STATE OF VERMONT

BEFORE THE PUBLIC SERVICE BOARD

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| **Green Mountain Power** | ) | |
| **Rate Increase Request** | ) | Docket No. 5983 |

# DIRECT TESTIMONY OF

# PAUL CHERNICK

**ON BEHALF OF**

**THE DEPARTMENT OF PUBLIC SERVICE**

Resource Insight, Inc.

OCTOBER 17, 1997

*The testimony of Mr. Chernick considers whether Green Mountain Power was prudent in the negotiation of the contract under which it is purchasing power form Hydro-Quebec and in managing that contract following its approval by the Public Service Board*

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## I. Identification and Qualifications

**Q: Please state your name, occupation, and business address.**

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

**Q: Are you the same Paul Chernick who filed testimony on October 7 in this proceeding?**

A: Yes. My resume is filed in this case as Exhibit ____ (DPS-PLC-DU-1).

**Q: Have you testified previously on utility resource planning?**

A: Yes. I have testified on the prudence of utility supply and DSM decisions 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, preapproval, 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 of load-management rates;
- Docket No. 5980, on avoided costs for statewide DSM programs; and

- this Docket No. 5983, on Green Mountain Power's distributed-utility planning and its decisions with respect to its purchases from Hydro Quebec.

**Q: On whose behalf are you testifying?**

A: This testimony is filed on behalf of the Vermont Department of Public Service ("DPS" or "the Department").

## II. Introduction

**Q: What is the purpose of this testimony?**

A: I address the prudence of Green Mountain Power (GMP) in its decisions regarding its purchases of power under Schedules B and C3 of the Vermont Joint Owners (VJO) contract with Hydro Quebec (HQ), which I will refer to as the HQ-VJO contract or the HQ contract. The chronology of major events related to these purchases are described in the testimony of Mr. Saintcross and Mr. Dutton in this proceeding. The Company's purchases from HQ under this contract are roughly $40 million annually, nearly a quarter of total revenue, and are expected to exceed a billion dollars over the period 1998–2015.

**Q: What decision points do you focus on?**

A: I focus on two time periods:

- The period from 1986 to 1990, while GMP and Central Vermont Public Service (CVPS) were negotiating the contract, first on their own behalf and subsequently for the Joint Owners, and securing approval of the contract.

- The period in 1991 leading to the decision to give up the right to terminate the contract without penalty, or "lock in" the contract, as of August 28.

**Q: Please summarize your testimony about GMP's behavior in these two periods.**

A: In the first period, GMP laid the foundation for its future errors by developing some biases, beliefs and assumptions that persisted through the premature decision in August 1991 to lock into the contract. In addition, GMP negotiated and signed a contract that did not allow the Vermont utilities to reduce their purchase commitments without renegotiating the entire contract. This feature of the contract put the Board in the uncomfortable position of approving or rejecting the entire firm contract.

The Integrated Resource Planning (IRP) report that GMP produced in 1991 was also the basis for other filings and, according to GMP, for the decision to lock in the contract. Considering the importance of the purchase, GMP's analyses of the contract's economics were inadequate, in terms of the range of analyses performed, the clarity of communications between management and analysts, and the tracking of changing conditions in the energy market. As I show below, the Company failed to comply with Board orders, and treated the HQ purchase more favorably and less skeptically than it did other purchases and especially DSM.

These errors culminated in GMP's failure to properly review the cost-effectiveness of the HQ purchase in the light of information it had available prior to the early lock-in. To make matters worse, GMP conducted no analysis of the costs and benefits of locking into the contract in August 1991, rather than waiting for the three additional months then available, even though the economics of the purchase were clearly deteriorating. The early lock-in decision was made on the spur of the moment, and rushed past the other VJO participants in a hastily-convened conference call.

At the time of the early lock-in, GMP planning staff were, or should have been, in possession of enough information to have justified delay of the lock-in. Specifically, GMP had realized that the fuel-price forecast it had been using to evaluate the purchase was at the high side of the plausible range. Lower fuel prices would cut heavily into the economics of the HQ contract. In short, a combination of inadequate direction from GMP management, inadequate monitoring of changing conditions, flawed analysis, and inadequate communications, lead GMP to lock into the contract prematurely.

**Q: What was the result of GMP's decision to lock in on August 28, rather than waiting to the end of November?**

A: By November, GMP's technical staff should have been able to do the necessary analyses, and should have found that the purchase was no longer clearly economic. If management had been made aware of this information, and had acted appropriately, GMP would have withdrawn from the project or insisted on another extension to the deadline. Any significant additional delay would have given the Vermont utilities time to reanalyze the purchase, and they would have found that it was no longer economic. Had GMP refrained from locking in early, the Company and, likely, the rest of the Vermont utilities that were purchasing power under the contract, would have far lower power-supply costs today, with either a better contract with HQ or none at all.

**Q: Were any of these GMP actions imprudent?**

A: Yes. The imprudent actions (or inactions) are as follows:

- Failing to specify in the contract the effect of partial approvals and withdrawal of participants.
- Structuring the contract so that GMP could not revise its contract elections after the PSB ruling without triggering renegotiation.
- Biasing the 1991 IRP analyses toward the HQ purchase.
- Failing to compare the purchase to the next-best alternative.
- Failing to adequately monitor changing market conditions.
- Inadequate communications between management and the analysts.
- Failure to analyze the costs and benefits of the early lock-in.
- Failure to update the economic analysis of HQ prior to the lock-in.
- Failure to develop the resource alternative to the contract, as required in Docket No. 5330-D.

**Q: Are you confident that GMP was imprudent in each of these areas?**

A: In some areas, all that can be determined from the documentary record is that GMP cannot show that it took appropriate actions. It may be that some of GMP's actions were prudent, but that GMP did not document those actions at the time, or has lost all the relevant documentation. In many cases, we have GMP's testimony confirming the inadequacy of GMP's actions. For example, GMP witnesses agree that there was no analysis of the contract specifically to support the early lock-in, and no analysis of the benefits of delay. We also have the deposition of Mr. Dutton, GMP's primary negotiator on the contract, in which he acknowledges that he does not know what would have happened if the Board or GMP had attempted to cancel a portion of the contract, because we do not know what HQ would have done.

In many cases, even if GMP did what it claims and far more than can be demonstrated on the record, its actions were inadequate to the point of imprudence. For example, it is possible that the analysts regularly met with and briefed management on their results, and received guidance on the questions that were most important for upcoming management decisions, but that all documentation (agendas, memos, handouts, slides, flip charts, meeting notes, and so on) have been mislaid. However, it is GMP's testimony that at least most of the alleged communication was oral. These complicated numerical analyses, dependent on many inputs and producing many outputs, could not have been successfully communicated orally, so whatever documentation might be missing would not establish the Company's prudence.

In any case, failure to document this decision, which the Board described as "the most important power purchase contract ever considered by this Board" (Docket No. 5330-E, Order of 4/22/91 at 3), and failure to retain whatever documentation existed, was in itself imprudent. The failure to maintain this documentation would hamper any subsequent attempts to update analyses to reflect changing circumstances (which GMP failed to conduct adequately) or to pursue any potential future suit against Hydro Quebec for misrepresentation or for damages resulting from any default.

**Q: Were there problems created by GMP's failure to provide documentation?**

A: Yes. Rather than identify and reference which documents were responsive to each discovery request, as is normal in practice, the Company chose to place all HQ documents in one room and direct he parties to search the boxes to find materials relevant to various questions. The Company has been slow to respond to discovery, even to identify and provide the documents and analyses it describes in direct testimony as the evidence for GMP's prudence in entering into the contract. For example, on August 14, the Department requested copies of materials presented to GMP's Board of Directors regarding the purchase; the documents were not provided until September 26. In response to many requests for the basis of its testimony, GMP directed the Department to review the entire docket in one or several proceedings, plus boxes of workpapers and personal files. Files accumulated slowly in the document room, without any indexing scheme. Identifying what documents have been provided, and which particular documents GMP might mean in a particular response, have been time consuming. Even when the Department was able to identify documents it wanted, GMP sometimes took inordinate periods of time to get those documents copied, and in some cases left the copies in GMP's document room, rather than delivering them to the Department. As a result, the parties have only recently received copies of important documents, limiting their ability to review and analyze the contents and conduct follow-up analysis.

I cannot recall a proceeding in which the utility was so reticent in providing historical documentation of a decision for which it was seeking cost recovery.

Q: **Have you been able to determine what GMP's analyses, had they been adequate, would have indicated about the economics of the purchase immediately prior to the lock-in, or between the lock-in date and the November deadline?**

A: Not exactly. Neither the 1991 IRP, which GMP generally describes as summarizing its analyses prior to the early lock-in, nor the materials made available on discovery, include any clear comparisons between a least-cost supply plan with HQ power and a least-cost supply plan without HQ power. The IRP describes only two comparisons of Schedule C3, or a portion thereof, to three other resources (none of which is a least-cost resource itself), and both these analyses use the high fuel-price forecast and arbitrary supply alternatives.

As described in §III.D.2 below, GMP's comparison of the HQ contract to the CoGen Lime Rock plant found that the HQ contract was more expensive than the alternative until 2010. Correcting this comparison to reflect alternative purchases that were less expensive than CoGen Lime Rock, and otherwise correcting GMP's errors, suggests that HQ power was more expensive than the least-cost alternative through the end of the contract. That information in itself should have been enough to cause GMP to decline to lock into the HQ purchase prematurely in August 1991.

Since market conditions were generally moving in directions unfavorable to the HQ contract proposal, waiting until the November 30 deadline to decide on whether to lock into the contract would likely have led to cancellation or modification of the contract. In particular, GMP started reviewing supply options using its low fuel-price forecast shortly after the lock-in (and perhaps even shortly before). With lower costs for oil and natural gas, the HQ contract would be even more clearly uneconomic.

**Q: If GMP had opposed the early lock-in, is it reasonable to believe that the lock-in would not have taken place in August?**

A: Yes. Based on CVPS's testimony in Docket 570, its support of the early lock-in appears to have been driven by a broad consensus among the Joint Owners. However, if GMP had opposed the early lock-in, and discussed the results of its cost-effectiveness analysis with the other participants, it is unlikely that the Joint Owners would have voted to lock in early, for two reasons. First, proceeding to an unnecessary early lock-in, in the face of unfavorable news, would have exposed the participants to prudence reviews. Second, most of the other Participants had opted for delivery of HQ power in the early 1990s, when it would clearly be less cost-effective than in 1995, when GMP's purchases were to start.

**Q: If the Joint Owners had waited until late November to decide on the lock-in, is it likely that the participants would have decided to lock in?**

A: No. In September, GMP apparently came to take the low fuel-price projection more seriously, which would make the purchase look worse against the most promising options, such as purchases from gas- and oil-fired utility plants and cogenerators, and participation in future gas-fired combined-cycle plants. Other participants' purchases started earlier than GMP's; if they had been afforded additional time to update their HQ analyses, those results would have looked even worse than GMP's.

Given the waning interest in HQ power from New York, the only other potential purchaser with a pending firm power contract, the Joint Owners would have known that their bargaining position with respect to HQ was improving, and should have been able to negotiate either a further delay in the commitment, or substantial long-term downward revisions in the purchase price. If these efforts had failed, GMP and the Joint Owners should have been in possession of sufficient information to cancel the contract at the November 30 deadline.

**Q: What would have been the basis for that cancellation?**

A: As I understand §1.3 of the contract, any party could back out of the contract if it was not satisfied with a regulatory approval. In the late summer and fall of 1991, GMP and the other VJO participants should have been aware that the cost-effectiveness of the contract—and hence the prospect for utilities' recovery of the contract costs—was very much in doubt. The utilities should therefore have concluded that certain of the conditions of the approval in VPSB Docket No. 5330 were no longer satisfactory, given the factual context. Mr. Dutton expressed his belief that changing facts, such as identification of additional DSM potential, would have allowed GMP or the Joint Owners to terminate the contract without liability (Deposition of C. L Dutton (included as Exhibit____DPS-PLC-P-3) at 68).[1]

**Q: How much less would GMP's power costs be today if it, or the Joint Owners as a whole, had not locked into the HQ contract?**

A: That would depend on what actions GMP, the Joint Owners, and HQ would have taken after August 1991. Predictions concerning the behavior of people in hypothetical alternative histories are always speculative. The continuing decline in load forecasts, fuel-price forecasts, and market power costs, plus likely re-examination of the contract by the Board, would probably have led to either the termination or reduction of Schedules B and C, or to steep reductions in the prices. In the event of termination, GMP might have opted to sign another long-term contract. However, few major long-term power-purchase commitments were made by New England utilities after the end of 1991.

[1]Mr. Dutton's deposition in this proceeding is attached as Exhibit____DPS-PLC-P-3, and Mr. Saintcross's deposition in this proceeding is attached as Exhibit____DPS-PLC-P-7. All references to depositions in this testimony are to those exhibits.

The Company would more likely have purchased power primarily on the short- and medium-term market. As a result, the rate-year cost of GMP's replacement power for HQ would probably have been close to the market value of that power, or roughly $20 million less than the cost of the purchase.

## III. Pre-1991: Laying the Foundation

**Q: Please describe the events relevant to this testimony that occurred prior to negotiation of the final contract.**

A: The HQ-VJO purchase started with GMP and CVPS efforts to develop a massive purchase from HQ. In January 1987, Mr. Dutton prepared the "Talking Points for Meeting Regarding 1,000-MW Project," attached as Exhibit____DPS-PLC-P-4, which describes the efforts of GMP and CVPS to arrange new transmission through western Vermont to import 1,000 MW of HQ power starting in 1995. This document (at 4)stresses the "Vermont utilities' leadership role" and suggests that the import would occur through "either joint venture, partnership or corporate enterprise of the Vermont utilities [with] supporting participation by NEPOOL members." The "Talking Points" also refers to

- the sale as being from HQ to the Vermont utilities, rather than a Vermont-led consortium of NEPOOL utilities.
- FERC regulation "with respect to rates," which would not apply to HQ's sales to US utilities, but would apply to subsequent wholesale transactions within the United States.

Both of these points suggest that GMP and CVPS were proposing that Vermont utilities—mostly GMP and CVPS—become wholesalers for a huge amount of power to the rest of New England.

The transmission plan failed, but the same utilities continued to work on a contract with HQ, eventually producing the VJO contract for up to 500 MW of Schedules B and C.[2] Vermont utilities actually elected 450 MW of this contract, of which 110 MW were cancelable by the purchasers by various dates. The Board approved the 340 MW of firm elections in Docket No. 5330 in October 1990, but told the purchasers to cancel the cancelable portions unless they received separate approval for those increments. No such permission was requested. Due to voter rejection of various municipal utility entitlements and the Rural Electrification Administration rejection of the Vermont Electric Cooperative's entitlement, the total VJO contract shrank to 310 MW, of which GMP has 114.2 MW, consisting of 67.6 MW of Schedule B and 46.6 MW of Schedule C3.

**Q: Why might GMP and CVPS have been interested in setting up a purchase as large as 1,000 MW?**

A: There are at least two potential reasons. First, the utilities were upset with what they saw as competition from the Department, in its role as the statewide purchaser of power from Quebec and Ontario. GMP was particularly concerned that the State would compete for wholesale customers. This concern is expressed in the memos to the GMP Board of Directors attached to the Board of Directors minutes from 1/27/87 (co-authored by Mr.

[2]This proposal is summarized in an attachment to the 6/2/87 Board of Directors minutes, attached as Exhibit____DPS-PLC-P-5.

Dutton) and 3/4/87, attached as Exhibit____DPS-PLC-P-5.[3] Using up all available transmission from the north and west, including the Highgate connection the Department was then using for its major import, would eliminate this potential. The 500-MW proposal would have used all available capacity through the Highgate and NEPOOL interconnections, and required an additional 100 MW of unidentified transmission, which may have been intended to be through New York, reducing the potential for imports from New York and Ontario Hydro.

Second, both GMP and CVPS appear to have been too optimistic regarding their ability to resell HQ power to other New England utilities at a profit. This assumption is implied in the "Talking Points." Potential wholesale purchasers for HQ power through the Highgate interconnection are also mentioned in the 9/8/86 BOD minutes in Exhibit____DPS-PLC-P-5. This belief persisted into 1990, when GMP testified in Docket No. 5330,

> From the early 1970's, GMP and other Vermont utilities have sold capacity and associated energy to other New England utilities from base-load sources, such as Vermont Yankee, at the full cost of service.... GMP consummated these transactions during a period of excess generating capacity in the New England area. We see a much stronger market available in the 1990s....
>
> GMP... is confident of its ability to sell any excess energy and capacity at full cost. (Thomas Boucher surrebuttal, February 16, 1990, at 4–5)

and CVPS testified,

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[3]The Board of Directors minutes, and their attachments, were heavily redacted before being provided to the Department, even with respect to HQ issues. At least one HQ-related attachment was not provided at all. The nature of these redactions has not been described, so we have no idea what else might have been provided to the BOD.

> Central Vermont's extensive experience in off-system sales demonstrates that such sales are made at least at the full cost of full capacity *and* energy. Ratemaking throughout the years in Vermont recognizes that fact. There is no reason to believe that trend will not continue in the future. To the contrary, the market for sellers in the Northeast should improve. (Bentley surrebuttal, February 16, 1990, 4)

**Q: How did these attitudes affect subsequent decisions?**

A: By 1991, GMP and CVPS had worked for as much as five years to secure the HQ purchase. The project had started as an attempt (among other objectives) to increase the utilities' prestige and position with respect to the Department and other New England utilities, and to produce profits on resale. The HQ-VJO contract as approved by the Board significantly limited the Department's ability to import power (by using all firm transmission capacity) and cemented the Companies' leadership role among the Vermont utilities. The Companies had long believed that HQ purchases were almost risk-free, since they assumed that they would be able to sell any excess at cost or better. These were to become an expensive set of preconceptions for GMP, CVPS, and their customers.

**Q: Aside from the later effects of preconceptions formed in this period, did GMP make any errors in this period?**

A: Yes. GMP did not understand the contract provisions regarding the effect of regulatory rejection of the contract, or approval on unsatisfactory terms (Dutton deposition (Exhibit____DPS-PLC-P-3) at 53–54).

The original contract provided that "each party" could withdraw from the contract if it did not receive satisfactory approvals (§1.3); this section appears to refer to only two parties, HQ and the Joint Owners.[4] Section 17.1 also stated that the Joint Owners will be treated as a single party for most purposes in the contract. In addition, the contract specified total MW values for all Vermont purchases, not utility-specific purchases.

The original contract had no drop-dead or lock-in date, no limits on the range of approvals that the parties could find unsatisfactory and use as a justification for terminating the contract, and no deadliness for determining that approvals were unsatisfactory. In Amendment 2, signed on September 19, 1990, the Joint Owners agreed to resolve any regulatory concerns by April 1991, to limit its opportunities to back out of the contract to conditions in Docket 5330 and the NEB proceeding, and to accept a 90-day deadline on terminating the contract following unsatisfactory orders.

The original contract appears to have allowed the Joint Owners to terminate the contract when the municipal and cooperative utilities failed to receive various approvals. Amendment 2 appears to have eliminated that option. In any case, the contract never gave the Joint Owners the option of reducing the size of the purchase to reflect these withdrawal of individual utilities, without renegotiating the entire contract. Mr. Dutton indicated in his deposition (at 53–54) that he believes that HQ decided to allow the municipals to withdraw without requiring either a step-up by other participants or a renegotiation of the contract, but that nothing in the contract required HQ to allow this sort of change. He did not know whether HQ

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[4]I am not offering this testimony as an expert on contract law. The contract language on this point appears to be in simple English, although there may be subtleties of which I am unaware. My reading is consistent with Mr. Dutton's testimony in his deposition at 52–55.

would have reacted the same way had GMP found its approval unsatisfactory.

The contract also does not provide for partial approvals. If the Board had approved Schedule B and Schedule C3, for example, but rejected Schedules C1, C2, and C4, the contract appears to require the Joint Owners to withdraw from the contract in full. Mr. Dutton (deposition at 54–55) does not know whether HQ would have allowed such a partial withdrawal or not. Withdrawal from the contract could have required renegotiation, unpredictable delays, and potential price increases.

While the Company at some times suggests that the Public Service Board could have partially approved and partially rejected the firm portion of the contracts (IR DPS 1-320, 1-321, and 2-52; cited Company responses to interrogatories are attached as Exhibit____DPS-PLC-P-6), the testimony of Mr. Dutton—GMP's principal negotiator for the contract and current Company president—is that no such right is inherent in the contract (deposition at 54–55).[5]

**Q: What was result of this lack of clarity regarding the effect of partial approvals?**

A: This confusion later tied the hands of the Public Service Board, which did not believe that it had any choice regarding the level of the purchases. The Public Service Board reduced the contract as far as it could, without requiring the Vermont utilities to withdraw, but found

[5]The Company's discovery responses in this docket are cited in this testimony as "IR DPS 1-__," "IR DPS 2-__," or "IR IBM 1-__," depending on whether they are from the Department's first set, the Department's second set, or IBM's first set. All cited responses from this case are attached in Exhibit____DPS-PLC-P-6.

> Because the 340 minimum has been presented legally as an "all or nothing" purchase, and because the evidence is clear that for Vermont as a whole, 340 MW is preferable to rejection of the entire proposal, we approve purchase of the minimum contractual amount. (Docket No. 5330, Order of 10/12/90, p. 34)

Towards the end of hearings in Docket No. 5330, HQ was threatening that negotiating any new contract would take at least three years, and that the new prices would not be as good as the old ones.[6] (Testimony of J. Guevremont, 2/30/90, at 104–107). Since the utilities had started taking service under Schedule A in 1990 and under Schedule C1 in 1991, and would lose 150 MW of Highgate power in 1995, the Public Service Board was under considerable pressure to approve at least some of the purchase. The Public Service Board believed that meant it had to approve the entire 340 MW of firm elections: it is not clear whether the Board actually had any choice between zero MW and 340 MW, or whether GMP believed at the time that the Board had any such choice.[7]

**Q: How could the contract have been clarified in this regard?**

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[6]The concern was that a "most-favored-nation" clause in the HQ–New York contract would require a reduction in those prices if HQ negotiated a lower-priced contract with any other utility after the signing of the HQ-NY contract. The HQ-NY contract was more expensive than the HQ-Vermont contract. To maintain the prices in the NY contract, HQ would have to increase the price to Vermont in any new contract.

This problem was not insurmountable. To work around similar problems, HQ and the Vermont utilities have reduced effective contract quantities and prices through creative side deals that do not change the contract itself. These side deals would not appear to trigger the most-favored-nation clause.

[7]If GMP believed during Docket 5330 that the Public Service Board had any such option, the Company does not appear to have made any effort to communicate that view to the parties and the Public Service Board.

A: I cannot suggest specific language, which would be a matter for contract lawyers. However, the provisions in §1.3 of the original Contract, or §1.4 of Amendment 2, which allow for opt-out, could have specified the effect on such a decision by one utility on the other Vermont utilities' obligations, and on the validity of the contract. The same section could have allowed a utility to reduce its take of HQ capacity, and the size of the contract, if the approvals of the remaining capacity were unsatisfactory. If HQ required limits on these reductions by schedule, utility, or (more likely) for the Joint Owners as a whole, the contract could still have specified that it would remain in force so long as Schedule B remained in full force, or so long as the contract remained above some specific amount satisfactory to the parties.

**Q: Was the problem caused by linkage between utilities and Schedules exacerbated by any other features of the contract?**

A: Yes. One was that the contract required that the elections for Schedule C be finalized by November 30, 1988.[8] This timetable did not give the VJO utilities time to seek prior approval from the Board. If the elections had been held open to the drop-dead date in the contract, the Board would have had the opportunity to review the economics of the purchase and approve or reject utility proposals. The Board would then have had the option of eliminating proposed firm commitments, down to the level of Schedule B, without jeopardizing the entire purchase.

The timetable for the contract (signed December 4, 1987) was laid out so that the VJO utilities first determined (by August 1988) their Schedule C elections, and then filed for Public Service Board approval. However, that

[8]This was a delay from the original August 1988 deadline.

filing—the most important supply planning decision ever put before the Public Service Board—did not occur until February 1989. Under these circumstances, the delay of the Public Service Board order beyond the start of purchases under the contract was almost inevitable, increasing pressure on the Board not to cancel the entire project. Simply allowing the election and review periods to run simultaneously might have avoided this problem.

**Q: How else could the problem of Schedule A starting during the Board's deliberations have been ameliorated?**

A: I see no reason that the contract could not have been two or even three separate contracts, so that the non-controversial Schedule A could have gone into effect on schedule on November 1, 1990, without being linked to the more-expensive and longer-term Schedules B and C.

**Q: Were the issues you have just discussed adjudicated in Docket No. 5330?**

A: No. This section has discussed the two sets of issues, neither of which was relevant to the forward-looking contract review in Docket No. 5330:

- The factors that may have contributed to GMP's failure to consider critically the economics of the HQ contract in 1991. Since that failure had not occurred at the time of Docket No. 5330, the Board was not in a position to review the precursor events.
- The prudence of the contract structure that limited the Board's options. While the Board complained about those limits in its order in Docket No. 5330, and explored the feasibility of relaxing them, I am not aware of any examination in that docket of the prudence of the contract structure.

The review of the prospective prudence of a power-supply option is rarely combined with any examination of the historical prudence of the failure to develop other options.

## IV. The 1991 IRP and the Early Lock-in Decision

**Q: Please describe the major events and activities related to the HQ contract in 1991.**

A: Two strands of events converged in 1991, one regarding GMP resource planning and the other directly related to the HQ contract. On the resource planning track, GMP developed its second IRP, replacing the version developed in 1989. In the analyses related to the 1991 IRP, GMP assumed that its shares of Schedules A & B were committed, and conducted only very limited analyses of potential alternatives to Schedule C3. That IRP was approved by the Public Service Board in 1994, long after GMP had waived its rights to terminate the HQ contract.

On the HQ track, the Board had already approved the overall VJO purchase. Most VJO utilities, including GMP, filed analyses justifying their shares of the VJO-HQ contract in Docket No. 5330-A on December 12, 1990. GMP used its limited analyses of Schedule C3 in that docket.

In September 1990, the Canadian National Energy Board (NEB) issued an export license to HQ for the VJO sale, but imposed Condition 10, which conditioned the approval on compliance with Canadian environmental law. This condition worried both HQ and the Joint Owners, due to uncertainties in how a future NEB revocation of HQ's export license (potentially many years into the contract) might interact with the contract's terms.

- Hydro-Quebec was concerned that revocation would be considered to be government action after the lock-in dates of the contract, which would render HQ (as the party whose government required termination) liable in damages for breach of contract.
- The Joint Owners was concerned that revocation under Condition 10 would be considered a pre-lock-in event (a "condition precedent"), even if it happened years later, in which case HQ would not be liable for damages from the cancellation, and would be able to keep the front-loaded payments under Schedules B and C without paying any compensation to the Joint Owners.

The Joint Owners and HQ first negotiated Amendment 3, which would have extended the deadline for withdrawing from the contract without liability on the basis of objections to regulatory approvals to April 1992, and compensated the VJO participants for their front-load overpayments. That Amendment was filed with the Board on April 5, 1991. On April 22, 1991, the Board issued an order in Docket No. 5330-E

- finding that Amendment 3 constituted a major change in the contract, which it could not consider while Docket No. 5330 was still on appeal;
- determining (at 5) that the proposed changes to the contract "favor Hydro-Quebec more than they do Vermont's utilities;"
- criticizing the Joint Owners for spending more than five months negotiating Amendment 3 and giving the Board only 25 days to review it;
- requesting remand of Docket 5330 from the Vermont Supreme Court;
- suggesting (three times, at 3, 11, and 13–14) that the parties negotiate "an amendment that *merely* preserved the status quo for a period of

forty-five days, in order to allow consideration of the merits of Amendment No. 3 following such remand" (original emphasis).

Instead of giving the Board the 45 days it requested, the Joint Owners instead filed a more limited Waiver and Release, and "announced that Hydro-Quebec was likely to cancel the Contract if the Waiver was not executed by April 30, 1991" (Docket No. 5330-E, Order of 4/30/91), four days after the Waiver came before the Board. The Board approved the Waiver and Release, which pushed the lock-in date to December 1, 1991, and required that the Joint Owners file any other necessary amendments to the Contract by September 15, 1991, which would give the Board the 45-day review period it had sought in the previous order.

In August, the Canadian appeals court overturned Condition 10, and HQ offered to waive its potential exemption from damages if Condition 10 were reinstated by the Canadian Supreme Court. HQ also concluded a sell-back agreement with CV and other VJO utilities (not including GMP), to reduce their costs in the first years of the contract. At this point, the Joint Owners agreed to give up its rights to cancel the contract based on regulatory approvals, and locked into the contract on August 28, 1991. I will refer to this event as the "early lock-in."

**Q: Why do you discuss the IRP and the early lock-in decision together?**

A: The IRP cannot be fully separated from the decision on early lock-in. While the IRP was not filed until October 1991, GMP has asserted that the IRP analyses were substantially complete before the lock-in, and formed the foundation and support of GMP's decision to lock in (IR DPS 1-251 and 2-37; Saintcross Deposition (attached as Exhibit____DPS-PLC-P-7) at 27–29 and 58–59 Exhibit____DPS-PLC-P-3 at 80). In GMP's view, the IRP demonstrates the adequacy and prudence of its monitoring of conditions relevant to the HQ contract and the lock-in decision.

Q: **Was the IRP analysis well structured to support management decision-making on the lock-in decision and on the HQ contract in general?**

A: No. As is discussed in §IV.D below, Mr. Saintcross considered the IRP to be a "snapshot" of GMP's planning, which was a process, always subject to later changes. If GMP was to produce the required IRP filing (which had already been delayed), at some point it had to stop changing inputs, complete the analyses, print final copies of the exhibits, and write up the process and the results. All of this is quite true of any IRP process.

Unfortunately, the question posed by the HQ lock-in was very different from that posed by an IRP. The lock-in was the result of a specific decision, not a continuing process. The opportunity to change the HQ contract was vastly more restricted after the lock-in than before. Rather than cutting off changes in the analysis to produce a readable IRP report, supporting the lock-in decision required GMP to identify critical inputs and monitor those closely as it approached the date at which the decision might be needed.

Q: **How is the remainder of this section organized?**

A: I discuss the problems with the Company's performance in this period in the following five pieces:

- failure to comply with board orders,
- errors in the IRP analyses,
- problems in documentation and communication,
- failure to prepare for the lock-in decision,
- errors in the lock-in decision itself.

Because these issues are closely interrelated, there is necessarily some overlap and redundancy between these sections.

### *A. Failure to Comply with Board Orders*

**Q: In what ways did the Company fail to comply with Board orders?**

A: As discussed in more detail below, the Company

- treated DSM differently and less favorably than supply, particularly the HQ purchase, a violation of Board instructions in Docket No. 5270 and Docket No. 5330.
- failed to develop a specific alternative supply plan for replacing the HQ purchase in the event of cancellation, as required by Board instructions in Dockets No. 5330 and No. 5330-E.
- failed to monitor adequately changing market conditions and HQ economics as required by Board instructions in Dockets No. 5330 and No. 5330-E.

**Q: How did GMP treat DSM differently from the HQ supply?**

A: The company treated DSM differently from HQ while conducting the analyses later published in the IRP, and again a few months later. In Section 6 of the IRP, GMP computed the cost-effectiveness of DSM under multiple sets of assumptions, including changing the order in which measures were selected, and computing cost-effectiveness in a "low fuel escalation" case. The IRP itself (not the appendices or workpapers) presented the results of these sensitivity analyses for the portfolio as a whole, and individually for each program, and in the C&I retrofit program, separately for fuel-switching and other measures. The low-fuel sensitivity analysis was considered so important that an entire page is given over to listing the annual low-fuel avoided energy costs by time period, even though no such tabulation was presented for the base fuel case.

The results are presented as annual values for nominal costs, cumulative net present value, and benefit:cost ratio, and as both tables and graphs. Altogether, this presentation of cost-effectiveness results and sensitivities takes up some 30 pages of the IRP, of which about a dozen are devoted to the low-fuel case. These analyses were all conducted in August 1991, prior to the lock-in (1991 IRP at 6–3).[9]

Section 7 of the IRP provides some analysis of from four to six (depending on the presentation) post-HQ supply alternatives under low-fuel, low-load, and high-load cases, but all these cases assume the presence of all schedules of the HQ contract. The presentation of the results of these sensitivity analyses takes only about eight pages, and provides only cumulative net present value of revenue requirements (CNPVRR).

The IRP does not discuss or consider any sensitivity analyses for the HQ contract. Most importantly, the purchase is never analyzed under the low-fuel case. No alternative is considered for Schedule B. Schedule C3 is compared to three alternatives, but only for base fuel and load conditions, and certainly not after all other cost-effective options have been screened into the plan, as was done for DSM. The entire discussion of the cost-effectiveness of the HQ purchase takes up less than two pages.

**Q: How did GMP treat DSM differently from HQ, a few months after the IRP?**

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[9]As discussed below, GMP adopted the low fuel-cost projection as base case forecast for DSM evaluation soon after the lock-in, without any new fuel price forecasts.

A: As discussed below, early in 1992 GMP reversed its position on using short-term fuel prices to determine long-term projections, and improved the modeling of economy energy. Both these changes were unfavorable to both DSM and HQ, but they were not applied to HQ analyses until after the early lock-in. After this change in perspective, GMP announced that the low-fuel results were correct after all, and that four of the nine DSM programs were not cost-effective.

**Q: Please describe GMP's failure to develop a specific alternative supply plan.**

A: In 5330-E, the Board instructed the VJO participants to

> seriously explore alternatives to the HQ contract, for use in the event that Hydro-Quebec does ultimately withdraw from the Contract.... [P]rudent utility managers must actively seek out other options and consider negotiations with potential alternative sources of efficiency and supply within the next few months (Order of 4/30/9 at 18).

Yet GMP never developed an alternative plan for use in the event of termination of the HQ contract. Indeed, neither the IRP nor GMP's other analyses in this period contains any computations of the cost of any plan without Schedule B. GMP had no criteria for the resources it would want to acquire in the event the HQ contract were terminated. In the Company's view, it was sufficient that it was confident that HQ could be replaced if necessary (IR DPS 2-31; Exhibit____DPS-PLC-P-7 at 80–83).

**Q: Why was seriously exploring alternatives to HQ and developing an alternative plan important?**

A: This omission was important for several reasons.

- The Company's obligation to its customers extends beyond meeting demand. If the HQ contract had been terminated, GMP would have needed to have some idea about the *least-cost* alternative to HQ power. Without this alternative plan, GMP was not prepared to move if the contract fell apart. If HQ canceled, GMP would have been out looking to replace some 35% of its energy requirements by 1995, without any plan or guidelines.

- Given the Joint Owners' stated concern that Condition 10 might result in cancellation of the contract, it was imprudent for GMP not to have constructed an alternative to HQ.
- Development of alternatives was one of the justifications for seeking the Waiver and Release. In Docket No. 5330-E, the utilities argued that the Waiver would permit an opportunity to search for alternatives and improve their negotiating position with respect to potential alternate suppliers (Order of 4/30/91 at 3). Yet GMP does not appear to have used the additional time provided by the Waiver and Release to develop alternatives or to negotiate with suppliers at all, whether from a better position or not.
- That same failure also affected GMP's attitude toward the inevitability of the purchase. If GMP had a feasible alternative plan available, the Company would have increased its freedom of maneuver and bargaining position with respect to HQ, and would have been able to seriously consider voting against the lock-in. GMP was concerned that if it did not lock in, it might lose the contract and be forced to rely on the second- or third-best alternative (Saintcross deposition at 31). Since the Company had not developed an alternative plan, it had no idea what the cost of losing the HQ contract would be, and therefore how much

risk it faced. The fear of the unnecessarily unknown drove GMP to accept the HQ contract as soon as feasible.

- The Company's failure to comply with the Board's order to prepare for the possibility of losing the contract implies that GMP was either negligent or overtaken by an attitude that the purchase was inevitable. The Company did not adequately explore the least-cost alternative to HQ power. The evidence suggests that GMP never had any intention or expectation of losing the contract.

**Q: Please describe GMP's failure to monitor changing conditions.**

A: The Public Service Board, in its Order in Docket No. 5330, required utilities to continually monitor contract economics, even after the lock-in, which was then expected to be much earlier, so that they would be ready to negotiate sellbacks (beyond those ordered by the Board) or take other actions if the contract were no longer cost-effective. As Mr. Saintcross summarized these requirements, "The Board also made it clear that utility management would have the ongoing obligation to address the possibility of unexpected change in market conditions...causing future surpluses of VJO Contract power that would in turn require mitigation" (prefiled. at 25).

As discussed below, GMP made little effort to track changing market conditions, or even to identify the critical parameters and the values at which re-evaluation of the contract was necessary. Nor did GMP approach the limited data it had collected in a manner reasonably calculated to produce the decision that would maximize ratepayer benefits. The Company repeatedly states that its analyses were directed to meeting specific Board requirements and perfecting the approval of the contract (IR DPS 1-244; Saintcross deposition (Exhibit____DPS-PLC-P-7) at 27–28, 49, 77). Providing specific analyses required by the Board is a necessary condition of compliance, but it is not sufficient to satisfy the requirement that utilities monitor market conditions.

### *B. The Flawed Analyses in the 1991 IRP*

**Q: What topics were covered by GMP's 1991 IRP?**

A: The important parts of the IRP for the purposes of my testimony are:

- Section 4, which considers alternative supply resources. The analysis starts with a plan consisting of existing resources, HQ Schedules A and B, and new gas turbines (GTs). It then compares alternative plans on the basis of CNPVRR, generally through 2004 or 2005, although occasionally for longer periods. This section screens and selects the HQ Schedule C3 purchase, as well as various amounts of CoGen Lime Rock starting in 1995,[10] purchases of NU oil capacity through 2005, and generic gas-fired combined-cycle capacity in 2001.
- Section 6, which screens nine DSM programs, under high and low fuel-price scenarios and for various order of commitment, as described above.
- Section 7, which provides sensitivity analyses of plans containing several supply resources under low fuel, low load, and high-load cases.

**Q: What were the problems in the analyses in the 1991 IRP?**

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[10]CoGen Lime Rock was a 68-MW gas-fired cogenerating combined-cycle power plant planned for Colchester, Vermont. The plant would have burned propane when gas was unavailable. GMP considered this project to be the most promising of non-utility projects, and signed up for 34 MW of the plant (and considered more), but it never attracted enough interest from other utilities.

A: The IRP analyses were biased toward HQ in the following ways:

- Use of only the high-end fuel price forecast for the HQ analyses.[11]
- Failure to compare the HQ contract to a least-cost alternative.
- Arbitrary limiting the range of alternatives to HQ power.
- Overstating the costs of GMP-owned resource additions.
- Inappropriate treatment of the NU purchase options.
- Differences in the treatment of supply- and demand-side resources, as discussed above.
- Errors in the treatment of economy energy, resulting in excessive use of peaking units and poor performance for potential competitors to HQ.

**Q: Please describe GMP's use of the high-end fuel price forecast for the HQ analyses.**

A: The Company based all the HQ analyses on its high-end assumptions about fuel prices. Since HQ prices were not indexed to fuel prices, but most alternative were, high fuel prices favored HQ. In addition, high running costs for existing units favored the HQ contract (and other baseload resources) over intermediate resources.

**Q: What is your basis for describing the fuel price forecast used in comparing HQ to other resources as "high-end?"**

A: The Company acknowledged that the fuel-price forecast referred to in the IRP as the "base" fuel case was at the high end of the reasonable range. According to the 1991 IRP (at 7-2), "GMP considers the current expected fuel forecast provided by WEFA to be conservatively high...." The "base"

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[11]GMP referred to the high fuel-price projection as the "base" price, but actually considered it to be at the high end of the plausible range (IRP at 7-2).

case was high enough that GMP felt that it did not have to test its IRP plan against a higher price forecast, only against a lower price forecast.

**Q: Is the choice of fuel-price projection important?**

A: Yes. As shown in Exhibit___DPS-PLC-P-9, taken from the 1991 IRP, the marginal energy costs with the high fuel-price forecast were 25–50% higher than those with the low fuel-price forecast.

**Q: Please describe GMP's failure to compare HQ to a least-cost alternative.**

A: The IRP analysis started by comparing the following three sets of expansion plans:

- The "base" plan with existing resources, Schedule B and gas turbines. This case was a starting point, not a serious candidate for a least-cost plan. This plan is represented by the first column of IR DPS 1-249.
- A set of cases in which 29, 34, 40, or 46 MW of GTs were replaced by Schedule C3.[12] The results of these cases are shown in the top portion of the second column of IR DPS 1-249.
- A set of cases in which 29, 34, 40, or 46 MW of GTs were replaced by a baseload purchase from NU (100% Connecticut Yankee in the winter, 70% Connecticut Yankee and 30% Norwalk Harbor 2 in the summer) from 1995 to 2006 and by coal gasification (IGCC) capacity thereafter.[13] The results of these cases are shown in the bottom portion of the second column of IR DPS 1-249.

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[12]Actually, the base plan did not have 46 MW of new GTs to replace until 2001.

[13]In an Integrated Gasification Combined-Cycle power plant, coal is gasified (partially oxidized to carbon monoxide, a flammable gas), the gas is burned, the hot gas turns a gas turbine (generating electricity), and the waste heat from the gas turbine is fed to a boiler that produces steam to turn a second turbine. Some of the steam is also used to run the gasifier; the

This analysis effectively compared Schedule C3 to the NU baseload plus IGCC. For both HQ and the alternative resource mix, replacing 46 MW of GTs produced the least present value.

The choice of the alternative mix of resources was arbitrary. NU, in its power supply offer (included as Exhibit____DPS-PLC-P-10) had offered GMP shares in five units and others were probably also available if GMP were interested. GMP selected its baseload NU mix without checking to ensure that the mix was least-cost, compared to (for example) an all- nuclear mix, or one with more oil, or a mix with oil in both the summer and winter. Nor does GMP have any coherent explanation of how it decided to use the IGCC as its long-term baseload resource (IR DPS 2-21).

**Q: What was the effect of using the NU baseload mix GMP selected, rather than an alternative?**

A: For baseload operation, at GMP's "base" fuel price, Connecticut Yankee would cost just about as much as NU's oil plants. With low fuel prices, or if off-peak economy energy is available, the oil plants would be less expensive than Connecticut Yankee.

**Q: Did GMP compare the costs of the HQ purchase to an optimized size and timing of the NU baseload purchase?**

A: No. GMP assumed that the NU purchase amount would be equal throughout the period 1995–2005, as the HQ purchase would be. Since GMP did not need capacity, the purchase would have been more cost-effective if it were phased in over time. Until 1998 (the end of the baseload Merrimack

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gasification and power production are thus "integrated." A few demonstration IGCCs have been built, but they have never been a commercially important utility option.

purchase), GMP's results indicate that 34 MW of NU baseload was superior to 46 MW of the same resource (IR 2-38). An even smaller amount of NU baseload might have been even better in 1995–97; GMP did not test that option. Nor did GMP check whether an NU intermediate mix might be more attractive than the baseload for those early years.

**Q: Please expand on the problem posed by the choice of the IGCC as the long-term baseload resource.**

A: This was a significant change in GMP's approach to resource planning. Gas-fired combined-cycle units were the baseload resources used in GMP's 1989 IRP, the Department's analysis in Docket 5330, and most contemporaneous analyses. GMP was not able to explain why it changed to IGCC as the baseload resource in the 1991 IRP, or as an alternative to HQ (IR DPS 2-21).

When asked for its justification for this choice, GMP first claimed that it was driven by environmental benefits of IGCC (IR DPS 2-21). This explanation made no sense, since the emissions of gas-fired combined-cycle plants are lower than those of IGCCs. GMP then claimed that it "picked the IGCC to be a proxy for long-term base load technology" because of its high capacity factor (Saintcross deposition at 43). This explanation also does not hold up to examination, since gas combined cycles were operating at "higher load factors as well" (Saintcross deposition at 42–43; this deposition is included as Exhibit____DPS-PLC-P-7).

Nor would the least-cost alternative to HQ necessarily be a base-load resource. The HQ contract had a 75% capacity factor, much lower than many fully baseload resources. In any case, the least-cost alternative to HQ would not necessarily be dispatched in the same way as the HQ contract.

Perhaps GMP's choice of IGCC as the resource to compare to HQ originated with the design of the contract as a discount from the cost of a coal-fired plant (9/3/87–9/4/87 minutes in Exhibit___DPS-PLC-P-5).

**Q: What was the effect of the choice of IGCC as the baseload proxy?**

A: There were three implications. First, the IGCC was more expensive than a gas-fired combined-cycle plant, even at base fuel prices and even if the gas-fired plant were required to operate baseloaded.

Second, the use of the capital-intensive IGCC made the error in the treatment of capital costs (discussed below) that much worse.

Third, when GMP reduced its fuel-price forecast, the IGCC was even more uneconomic compared to the gas combined-cycle and other resources.

**Q: Did GMP compare HQ to any resource other than the NU Base–IGCC combination?**

A: Yes. After the first set of IRP supply comparisons (which chose 46 MW of Schedule C3 over both GTs and the combination of the NU Base purchase with IGCC capacity), GMP determined the cost-effectiveness of adding various amounts of CoGen Lime Rock, replacing additional GTs.[14] The results (shown in the third column of IR DPS 1-249) indicated that adding up to 30 MW would reduce total costs.

As the third step of the IRP development, GMP compared (1)a plan that included Schedules A and B, 46 MW of Schedule C3, and 30 MW of CoGen Lime Rock, as well as existing resources and new GTs, to (2) a similar plan replacing 5 MW of Schedule C3 with 5 MW more of CoGen Lime Rock. The

[14]Once GMP had selected 46 MW of Schedule C, its plan did not have any new GTs until 2001 and had 30 MW of new CT only after 2003. CoGen Lime Rock was to be added in 1995.

results for this second plan are summarized in the solitary box at the top of the fourth column of IR DPS 1-249. Like all the analyses that constituted the IRP development, these analyses used the high "base" fuel-price forecast.

The plan with more CoGen Lime Rock capacity was less expensive (in CNPVRR) than the plan with more HQ through 2005, the cutoff date GMP had used in making other decisions in the IRP. The extra CoGen Lime Rock capacity reduced CNPVRR through 2009. Thereafter, the case with the full 46 MW of Schedule C3 became slightly less expensive than the additional CoGen Lime Rock. The Company relaxed its usual preference for selecting the alternative with the least cost over the first ten years (in this case, 1995–2004), to select HQ based on its small benefits from 2010 on.[15]

**Q: Had GMP verified that CoGen Lime Rock was the least-cost alternative to Schedule C3?**

A: No. In fact, other IRP analyses found that CoGen Lime Rock increased CNPVRR compared to an equivalent amount of an NU intermediate purchase in 1995-2005, followed by construction of a gas-fired combined-cycle plant in 2006 (collectively, I call this the "NU-NGCC" option). The

[15]Interestingly, the 1991 IRP states (at 4-14), "CoGen Lime Rock first broke even against HQ C3 in the year 2010" and produced "small and risky CNPVRR savings beyond 2010." The actual results of GMP's analysis were the opposite: Schedule C3 first broke even against CoGen Lime Rock in the year 2010, with small and risky CNPVRR savings from Schedule C3 beyond 2010. When GMP thought that CoGen Lime Rock's benefits were after 2010, it wrote that those savings "did not justify larger CNPVRR losses in the earlier years—$955,000 by the year 2000 and $560,000 by the year 2005. Therefore, the Company's HQ C3 election was left at 46 MW" (ibid.). In fact, those losses were the extra costs of HQ over CoGen Lime Rock. Following the reasoning in the text of the IRP, GMP should have selected the five MW of CoGen Lime Rock, and reduced its HQ share. Regardless of which way the numbers went, when the costs were close, GMP selected HQ.

superiority of the NU-NGCC plan to CoGen Lime Rock is shown in IR DPS 1-249. It appears that GMP would have found the five MW of the NU intermediate-combined-cycle combination to have been less expensive than the five MW of Schedule C3, throughout the life of the HQ contract, even with GMP's other errors. I will compare these cases further below.

**Q: How did GMP arbitrarily limit the range of alternatives to HQ?**

A: The Company limited the range of alternatives in a couple of ways. First, as described above, GMP selected only arbitrary examples from the range of alternatives it had identified. GMP never compared any part of the HQ purchase to a gas-fired combined cycle, or a purchase followed by a combined-cycle, or a purchase followed by a delayed cogeneration option, or a different mix of the plants that NU offered to sell power from.

Second, according to Mr. Dutton's deposition ( at 55–56, attached as Exhibit____DPS-PLC-P-3), GMP focused only on those alternatives to the HQ contract that looked like the HQ contract, including the long-term nature of that purchase. Mr. Dutton actually expressed a preference for HQ's front-loaded costs , although he agreed that front-loading was not really a benefit.[16] This essentially limited the alternatives to new construction or an equally long-term contract for baseload power, although GMP did construct one alternative based on a ten-year NU purchase. In short, while there were many realistic alternatives, few were adequately analyzed.

Third, as described in §III.D.1, below, GMP did not seek out additional options.

[16]The belief in the inevitability, and perhaps even desirability, of front-loading may have its origins in the negotiation of the contract as a discount from the cost of a utility-owned coal plant (1/3/87–1/4/87 minutes in Exhibit____DPS-PLC-P-5)).

**Q: How did GMP overstate the costs of GMP-owned resource additions?**

A: In modeling the carrying charge for plant additions, GMP computed the costs in a manner that increased the CNPVRR for new GMP-owned power plants in the period used in the analysis, particularly those competing with HQ. In computing the CNPVRR, GMP used the annual revenue requirements of the new plants, with heavily front-loaded costs of capital recovery (Saintcross deposition at 46). These front-loaded revenue requirements reflect the way that costs are actually recovered through cost-of-service ratemaking. However, the revenue-requirements approach overstates the costs of owning a plant that would still be operating at the end of the analysis period, by including the high ratemaking costs during the early years of its life (which are in the analysis), and ignores the low revenue requirements that would accrue after the analysis.

While the revenue-requirements approach models actual ratemaking, and is therefore useful in estimating annual rate effects, it must be corrected for use in economic planning analyses. Including the revenue requirements for the IGCC from 2006 to 2015, and ignoring the benefits of having a 10-year-old plant in 2016 (built in 2006 dollars and one-third depreciated), biases the comparison towards HQ, which would leave no such asset when the purchase ends in 2015.

**Q: How can this problem be avoided?**

A: There are two approaches to matching carrying costs to time periods. The end-effects approach adds an adjustment to reflect the value of the remaining resources (such as the IGCC) at the end of the analysis period, to reflect the value of the resource at that time. The other approach is to use the economic carrying charge, which levelizes the carrying charges in real (inflationadjusted) terms, so that the carrying cost of any type of capacity in a given year is the same, regardless of when the plant was built. In general, the value of the plant in a given year is independent of its construction date, so this approach matches costs and benefits over time.[17] The economic carrying charges for a plant over its full life will have the same CNPVRR as the revenue requirements. Over part of the plant's life, the CNPVRR should be equal to the revenue requirements, minus the residual value of the plant at the end of the analysis.

The Company was aware of the problems raised by end effects, and had struggled with eliminating those effects in its 1989 IRP. In the 1991 IRP, GMP used the economic carrying charge in some analyses (such as the determination of the market value of capacity, where it reduced the value of DSM and excess short-run supply resources), but not in the central comparisons of the CNPVRR of various resource options.

**Q: How much did this error affect GMP's analyses of alternatives to the HQ purchase?**

A: Exhibit___DPS-PLC-P-2 shows the overstatement of capital costs per MW for the IGCC and natural-gas combined-cycle units used in various GMP analyses. Using the revenue requirements, rather than the economic carrying charge, added $235/kW to the CNPVRR of the IGCC through 2015, or $11 million for 46 MW of IGCC.

[17]There may be minor differences in the annual availability of the plant, such as during the first few years of break-in, and due to maintenance schedules. The differences in availability will cause some changes in value for particular years, but these generally average out.

**Q: What errors did GMP make in its treatment of the NU purchase options?**

A: The NU option started with an unsolicited proposal from NU to GMP, and apparently all the VJO participants. In that proposal, NU offered GMP a specific mix of capacity from (1) Connecticut Yankee, (2) three oil-fired units (Norwalk Harbor 1 and 2, and West Springfield 3), and (3) the Northfield Mountain pumped-storage plant. (The proposal is included as Exhibit____DPS-PLC-P-10). From the prices in the proposal, GMP constructed two other combinations of the nuclear and fossil plants for total of three options:

- the NU-proposed mix,
- the NU base mix described above,
- an NU intermediate mix, comprising equal shares of the three oil units.

These options are developed in a memo from GMP's J. R. Letarte (attached as part of Exhibit____DPS-PLC-P-11, which also contains other GMP internal memos).

The first error was that GMP compared HQ Schedule C3 to the NU base mix, rather than the NU proposal, even though Letarte recommended that GMP include the NU proposal since NU "designed it specifically for [GMP's] needs." The Company compared the intermediate mix to CoGen Lime Rock, and included in the IRP resource portfolio, but never compared it to the HQ contract.

The second problem was that GMP never used any NU purchase option, for any purpose, that included Northfield, which was 20–25% of capacity in the NU proposal. As Letarte notes, "Northfield Mountain is available only as part of a package because its price is very low." Indeed, the

Northfield capacity costs are less than those of new GTs, even though Northfield provides substantial benefits in shifting energy from low-cost to high-cost periods. These benefits are estimated in Exhibit___DPS-PLC-P-1 as $400,000 in 1991 CNPVRR for each MW of Northfield.

**Q: What differences in the treatment of supply- and demand-side resources were important in biasing the analysis toward the HQ purchase?**

A: These differences are described in §IV.A above. The IRP describes only two comparisons of Schedule C3, or a portion thereof, to other resources, and both these analyses use the high fuel-price forecast and arbitrary supply alternatives.

**Q: How did GMP bias the analysis towards baseload resources and away from those with greater operating costs?**

A: The Company did not properly incorporate the effects of economy energy purchases. The more economy energy is available and the lower its cost, the better an intermediate plant will fare better compared to a baseload plant. The inexpensive economy energy will be dispatched more with the intermediate unit, with greater running costs, than with the baseload unit.

I do not know exactly how economy energy was modeled in the IRP, due to the lack of detailed documentation, but GMP assumed that less economy energy was available than in the April 1992 run, and GMP considered even the 1992 run to be understating economy energy (GMP 4/30/92 internal memo (Exhibit____DPS-PLC-P-11) at 2).[18] We also know

[18]The IRP assumed that 40 MW of winter economy purchases were available at $36/MWh, while the 4/92 avoided-cost runs assumed 40 MW at $25/MWh, and 30 MW at $36/MWh (but only dispatched when the marginal cost reached $54/MWh).

the GWhs of generation from GMP's peaking units (the GTs and diesels), which run only when economy energy is unavailable, in 1991–97 for some of the IRP runs and for the April 1992, and actual values for various years.

| | Actual | 1991 IRP 46-MW NU Base Run | 1992 Avoided Costs |
|---|---|---|---|
| 1991 | 3 | 117 | NA |
| 1992 | 1 | 87 | 5 |
| 1995 | | 172 | 25 |
| 1996 | | NA | 27 |
| 1997 | | 168 | 53 |

In the 1991 IRP runs, one of the diesels was assumed to run at a 50% capacity factor, while the Berlin combustion turbine was assumed to run at 30% capacity factors.[19] This unrealistically high level of modeled peaker operation further supports the belief that the treatment of economy energy purchases was unrealistically restrictive. This problem would favor HQ compared to CoGen Lime Rock; if GMP had compared HQ to other intermediate-base units, the treatment of opportunity energy would have favored HQ there, as well.

### C. *Problems in Documentation and Communication*

**Q: What problems have you identified in the Company's communications regarding the HQ lock-in decision?**

A: I have identified the following problems:

- The Company's documentation does not support its claims to have been actively monitoring market conditions and compiling data.
- The Company does not appear to have ever assigned specific monitoring tasks and schedules to specific individuals.

[19]The economy purchases were dispatched at a 30% capacity factor in the IRP runs.

- There is no record of reports to management on the results of monitoring.
- Management does not appear to have raised any questions or instructed staff to monitor conditions or report back.
- No presentations on HQ economics are reported in the minutes of the GMP Board of Directors between the announcement of the proposed contract in 1987 and the discussion of sellbacks in 1992.[20]
- The GMP decision-making process cannot be traced during this critical period.

**Q: Does the Company claim to have been monitoring changing events?**

A: The Company claims to have made a "conscious decision to monitor market conditions and to study alternatives to the VJO Contract..." (Saintcross prefiled at 4, lines 10–11). The Company also claims that it "compiled" information during the summer of 1991 (Saintcross prefiled at 30; DPS 2-39, DPS 1-252). The Company's direct testimony in this case seemed to describe the amassing of information.

**Q: Did GMP clarify the nature of this "conscious decision"?**

A: According to Saintcross's deposition (at 47; the deposition is included as Exhibit____DPS-PLC-P-7), this was not really a conscious decision on management's part. Rather, the monitoring was "a function of having to prepare the IRP and use the best information we had." Further, when Saintcross referred to "compiling" information, that could consist of many

[20]The minutes of the Board of Director's meetings provide no evidence of any discussion or presentations concerning the cost and benefits of HQ, deteriorating economics, downward trends in fuel price forecasts, market price and load, what Saintcross (prefiled at 4, lines 10–11) calls the "conscious decision" to monitor, or costs and benefits of the early lock-in.

items, or just one. (deposition at 45, 64–65). So the "conscious decision to monitor" was really an implicit decision to "use the best information we had," even if that was just one item. The comprehensive data-gathering effort for the HQ contract review turned out to be simply routine collection of inputs for the IRP.

As one example, fuel price was a crucial determinant of the benefits of HQ purchase. Yet GMP could provide only one fuel-price forecast it had acquired in 1991, and Mr. Saintcross did not know whether analysts working for him had acquired other fuel price forecasts (deposition at 55).

There were certainly many other fuel-price forecasts in use in 1991, and many projected much lower fuel prices than did GMP's high "base" forecast.

**Q: What have you found in your examination of Company documentation?**

A: Considering that GMP was making a billion-dollar commitment to HQ purchases, there is surprisingly little documentation of what was done and when. There is no documentation of any analysis of the lock-in decision, apparently because there was never any such analysis (Saintcross deposition (Exhibit____DPS-PLC-P-7) at 80–83). In addition, there is no documentation of the facts that were put before management to weigh in the weeks immediately before the lock-in decision.

As for the IRP analyses, the Company has been unable to establish the dates of particular analyses. We are therefore unable to pin down which analyses were available to management at the time of the lock-in decision. Had management requested an update, some evidence would probably exist, easing the dating problem. There is no evidence that management ever requested any update, or were aware of the latest analyses at the time.

The Company also cannot provide any of the following information:

- A complete list of the studies that were performed as part of the IRP or lock-in decision (IR DPS 2-30, Saintcross deposition at 3).
- A detailed description of the alternative supply cases tested against HQ Schedule C3 (IR DPS 2-32, 2-34).
- Any catalog of the information compiled to support the decision (IR DPS 2-39).
- The analyses and information gathered between the lock-in and December 1, 1991 (IR IBM 1-26).

The Company's technical staff has suggested that the Department search through boxes of files and printouts to locate materials that may be responsive to these requests. Had management made an adequate effort to confirm the solidity of the economic performance of the HQ contract, some more-concise documentation would almost certainly remain.

Given the absence of documentation, all the Board has is the Company's assurances that GMP made a careful decision that just turns out to have been wrong.

**Q: What is GMP's explanation for the lack of evidence supporting any attempt to gather information and transmit it within the Company?**

A: The Company has two basic responses. First, it asserts that the 1991 IRP "is ample evidence that the Company monitored the market place" (IR DPS 2-33b). In fact, the IRP provides little such evidence, beyond the following activities:

- taking note of the NU offer.
- requesting the usual annual fuel-price forecast from WEFA.
- reading the NEPOOL CELT.
- reviewing the NEPOOL Monthly Fuel Report for April 1991.

- consulting with GMP's Systems Operations staff on typical energy purchase prices for the winter 1990/91 and summer 1991.
- reviewing GMP's short-term purchases for January–March 1991.[21]

Only the first three activities deal with any forecast data.

The IRP demonstrates that GMP assembled enough data to produce the "snapshot" of its planning process (Saintcross deposition at 63; included as Exhibit____DPS-PLC-P-7), but that is not the same as monitoring the market. If any other information was "brought to bear" on the decision (IR DPS 2-33b), GMP did not find it important enough to write down, at least in any form that has survived.

**Q: What was GMP's second explanation?**

A: The second explanation for the lack of documentation was that "Communications within the Company...were informal, usually comprised of meetings and verbal briefings." GMP claims that its "communications while not documented often, were efficient nonetheless" (IR DPS 1-225).[22]

> Because a lot of our work, again, was verbally communicated in this organization.... It was a small company. Things would float to the top and float back down in that manner. (Saintcross deposition at 57–58)

**Q: Is this a plausible mechanism for responsibly making decisions of the magnitude of the HQ purchase?**

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[21]The last three items were used in creating forecasts of market prices for short-term economy energy purchases (7/8/91 memo in Exhibit____DPS-PLC-P-11). The same memo also forecast the value of peaking capacity sales, but failed to provide any data on actual market prices.

[22]IR DPS 1-225 was referred to by many other requests for documentation, such as IR DPS 1-226, 1-227, 1-228, 2-25, and 2-26, which are not included in Exhibit____DPS-PLC-P-6).

A: No. This management style might be adequate for such routine activities as authorizing T&D investments, but would not lend itself to careful consideration of a big, complex decision that is very much number-driven.

In this environment, internal communications would be inadequate at best. Without a clear road map of the analytical framework, tabulations of the effects of changed assumptions, and comparisons of those sensitivity cases to actual conditions, management could not be expected to understand the issues, or ask the right questions. They would be unlikely to have had the even best information available within the Company, let alone the data that were never gathered, when they approved the HQ purchase.

**Q: Was upper management closely involved in determining what information was needed from the monitoring of changes in market conditions?**

A: No. The analysts appear to have worked without any clear directives from above. According to Saintcross (deposition (Exhibit____DPS-PLC-P-7) at 27), upper management did not directly request that he analyze the economics of HQ in 1991. Rather management was "aware we were going to be doing those analyses" in preparation for the 1991 IRP. Saintcross' focus was the IRP (deposition at 33–34), and any information that management may have received about changes in HQ economics would have been largely coincidental.

**Q: Has GMP's informal communication style worked well in other parts of the Company's operations involving complex analyses?**

A: No. As discussed in my prefiled testimony on distributed utility planning in this docket, GMP expended a fair amount of high-profile effort on DU planning for the Mad River Valley, without the DU planners knowing that an interruptible rate was under negotiation, or understanding the engineers' explanations of the potential overloads that were driving the need for T&D capacity, or understanding the terminology used by the DSM planners. Even two years later, these communications failures persist in GMP's DU planning.

**Q: Is the lack of documentation on the HQ decision typical of GMP's approach to all planning?**

A: No. On decisions that GMP considers important, it can produce detailed comparisons and analyses. For example,

- As discussed in §IV.A above, the IRP engaged in exhaustive analysis and documentation of DSM cost-effectiveness, even for analyses that GMP did not intend to apply promptly. As input factors (or GMP's view of those factors) have changed, GMP has redone its extensive DSM analyses, as demonstrated by the April 30, 1992 memo in Exhibit___DPS-PLC-P-11.
- As illustrated in the 5/13/92 memo in Exhibit___DPS-PLC-P-11, GMP carefully documented its monitoring of changing conditions with respect to the WESNEEX non-utility project.[23]
- The Company has provided extensive contemporaneous materials describing the negotiations and analyses with respect to the HQ sell-backs.

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[23]WESNEEX was to be a combined-cycle cogeneration plant, located in Williston, Vermont, burning firm gas delivered through Vermont Gas Systems.

- The Company was able to produce a very clear flowchart of its IRP analyses (IR DPS 1-249) and a table of the numerical results of the cases in that flowchart (IR DPS 2-38).

Considering that the decision to lock into the HQ contract was the most important purchase GMP had ever made, the Company should have been especially careful in structuring (and communicating about) the monitoring of conditions affecting the contract, and the economics of the contract. Instead, the opposite was true: the record indicates that GMP's approach was more casual with regard to the HQ lock-in than with regard to many less-important decisions.

**Q: What can the Board conclude from the quality of GMP's documentation of the data-gathering and analysis underlying the lock-in decision?**

A: The documentation is inconsistent with GMP's assurance to the Board that the Company employed a very careful and rigorous decision-making process in locking into the HQ contract (Saintcross prefiled at 3–4, 32–34). As discovery and depositions have demonstrated, GMP did little organized data-gathering and analysis, and if there were any tangible fruits of those efforts, the results never got to the decision-makers.

Careful consideration of a complex decision in even a moderately large organization requires written communication and rigorous documentation of analyses. As the 1988 Statewide Electric Plan stated,

> [I]t is vital that an adequate flow of useful, timely information reach all decision-makers.... Utility managers and regulators...must have an adequate flow of information...to make appropriate decisions....

> At a minimum, an adequate strategic situation analysis must include...a formal planning process and documentation of the results for internal and external communication. (Vermont Twenty-Year Electric Plan, 1988 Revision, Vermont Department of Public Service, 10/15/88 at I.2-6 to I.2-7)

The Company appears to have achieved neither adequate communication between analysts and management, nor adequate documentation in making the critical HQ decisions.

### *D. Failures in Preparation for the Lock-in Decision*

#### *1. Monitoring Changing Circumstances*

**Q: What should GMP have been doing in preparation for the lock-in decision?**

A: The Company should have at least been doing what it says it had been doing: monitoring market conditions (including regional economic factors, regional load and supply, and fuel price), compiling data, and "continuously [studying] alternative supply and conservation ... resources using up-to-date integrated planning assumptions." (Saintcross prefiled at 3–4). As GMP explained in its 1991 IRP,

> Planning is not an event—it is a continuous process. Evaluation of analytical protocols must be diligently pursued so that the planning process absorbs lessons learned on implementation of decisions and *does not blindly pursue solutions rendered uneconomic or otherwise impractical by external developments*. In any sense, any "plan" for the future is always in draft form. (1991 IRP at 2-2, emphasis added)

Unfortunately, GMP did not follow its own advice. The Company did not recognize any trends in market conditions that would justify another look at the economics of HQ. In 1991, GMP was so convinced that the Contract was a good deal that it ignored the warning signs available to it, and pushed ahead with an early lock-in.

The 1988 Statewide Electric Plan (at I.2-6) also requires utilities to compile and utilize adequate information to support resource decisions, in the section I quoted above:

> [I]t is vital that an adequate flow of useful, timely information reach all decision-makers...Utility managers and regulators...must have an adequate flow of information...to make appropriate decisions....
>
> It is essential that management understand the operating environment in depth. This understanding must be thorough and current to allow quick and knowledgeable reaction to changes in the strategic environment. Lack of understanding has led to precipitous and ill-advised commitments...in reacting to...short-lived opportunities. At a minimum, an adequate strategic analysis must include...continual monitoring.

**Q: What should have tipped GMP off that future market prices would be lower than GMP used in the limited IRP analyses of HQ economics?**

A: The Company knew that

- fuel prices were expected to be lower than those used in the IRP analyses of HQ economics, at least through 2005 (1991 IRP at 7-2).
- NEPOOL was in an excess capacity situation, expected to last to 2001 (7/8/91 memo in Exhibit____DPS-PLC-P-11 at 1).
- The load forecasts of NEPOOL participants had fallen "substantially... because of present and anticipated recessionary effects" (7/8/91 memo of Baslow to Saintcross at 1).
- Lime Rock was having difficulty selling its remaining output (1991 IRP at 4-3, 4-4).

**Q: What justification has GMP offered for ignoring these changes in market conditions?**

A: The Company has offered the following explanations:

- These changes were bound to be counterbalanced by changes favorable to the HQ contract:

> ...there's a multitude of assumptions that go into the analysis. Some are going to work against making a long-term decision, others are going to say; you still should make that long-term decision (Saintcross deposition at 50)

- It is impractical for the Company to redo its analysis every time it receives new information.
- The Company cannot let late-breaking events control its long-run analysis and decisions:

> So, the Company made the decision that it wasn't going to gain much more knowledge of going out in the year 2005 and 2008 by waiting another month or so.... you can wait until the very last day and some of the information could come in. And you're making a decision..., 20 years of length, on the basis of one piece of information.
>
> So, I think the judgment was made that the analyses that we had done in the summertime were good enough, well-thought-out snapshot of the future world. (Saintcross deposition at 63)

**Q: Was this approach consistent with GMP's approach to updating fuel prices and market conditions at other times?**

A: No. In September, 1992, Mr. Saintcross asserted that "short-term events will strongly influence the cost-effectiveness of...any decision regarding power supply sources." (Saintcross deposition (Exhibit____DPS-PLC-P-7) at 1–2) That letter was attempting to justify GMP's major reduction in fuel prices and economy-energy costs for use in updated DSM avoided costs.

**Q: Why was the Company's snapshot approach to the analysis of the HQ Contract inappropriate?**

A: I agree that it is unreasonable to expect the utility to redo its analysis for every change in assumption, regardless of the nature of the change, the effect on the decision and the dollars involved. However, the Company's monitoring of HQ economics during 1991 was far from adequate. There were significant changes in *long-term* expectations all unfavorable to HQ, the economics of HQ were highly sensitive to market conditions, and HQ was an immense financial commitment for GMP and for Vermont as a whole.

The Company failed to adequately examine the effects of the changing electric-power market on the economics of HQ. Specifically,

- The Company did not actively seek new information on trends and uncertainty in market conditions.
- The Company failed to update its HQ cost-benefit analyses for significant changes in its own expectations. In particular, GMP did not adequately test HQ against the low-fuel-price forecast, even though it knew the base case was too high and even though it treated the low-fuel forecast very seriously for evaluating DSM.[24] Indeed, the IRP did not test any part of the HQ purchase for any situation other than the base case, despite the requirement in the 1988 Statewide Electric Plan ( at I.2-10) that planning consider multiple futures.
- The Company failed to perform a reasonable sensitivity analysis. In a rapidly changing environment, a sensitivity analysis would have given GMP some idea of how market conditions affected HQ economics and

[24]The discussion of fuel prices in the IRP suggests that GMP found the low fuel price to be as likely as the high fuel price, and the low price projection became GMP's best-estimate forecast less than six months after the IRP was filed, without any new long-term data (GMP memo of 4/30/92 in Exhibit___DPS-PLC-P-11).

an estimate of the threshold assumptions under which the Contract would become uneconomic. The Company would then be able to respond to changes in expectations even if it were not able to do a rigorous analysis at short notice.

For HQ, constituting such a large part of GMP's energy supply, these sensitivity analyses should have been very thorough:

> Any analysis must recognize all foreseeable opportunity costs associated with the proposed action. The scope and rigor of sensitivity analysis must be in proportion to the exposure associated with the project. For low-cost projects with limited, contained risk, simple analyses may suffice. For very large commitments (absolutely or in relation the size of the utility), the economics of the proposal must be tested and quantified for each factor to which they may be sensitive. (Statewide Energy Plan at I.2-9)

The opportunity costs of the HQ contract were the lost opportunities to purchase lower-cost supplies, to which GMP gave short shrift. The HQ purchase was the extreme example of a "very large commitment" for GMP. Yet GMP varied the "scope and rigor of sensitivity analysis" *inversely* with project exposure, lavishing sensitivity analysis on DSM and smaller, shorter purchases, while ignoring the risks of the HQ contract.

**Q: What fuel price data did GMP compile?**

A: For its best estimate of fuel prices, GMP relied on a single forecast, the May 1991 forecast prepared by WEFA.[25] The Company made no effort to obtain more up-to-date WEFA projections for the HQ analyses it performed in Summer 1991. At times, GMP requested updates and received fall, winter, or summer forecasts. It usually received late summer forecasts for budgeting

[25] WEFA was at that time also known as Wharton Economic Forecasting Associates.

purposes. But in 1991, the Company received only the May forecast (Saintcross deposition (Exhibit____DPS-PLC-P-7) at 53–54). Since WEFA produced a fuel-price forecast every quarter, GMP could have obtained at least one more update before the August lock-in decision, and two updates before December 1991.

Neither did GMP consider the views of any other forecasters at the time:

> We relied pretty much on WEFA. They were a sound economic forecasting firm. (Saintcross deposition at 53–54)

WEFA may have been a "sound economic forecasting firm," but its fuel-price forecast, was in conflict with the forecasts prepared by other "sound" forecasters. Given the poor track record of fuel-price forecasters, GMP should have familiarized itself with a broader range of opinion.

**Q: Were the Company's efforts to obtain information on supply alternatives any better?**

A: Judging from the 1991 IRP, the Company's efforts were half-hearted at best. The only alternatives for which we know GMP obtained cost estimates (other than for the proxy units) are power purchases from Northeast Utilities, CoGen Lime Rock and WESNEEX. GMP made no effort to solicit power from New York utilities, from other New England utilities, or from Ontario Hydro, or to negotiate with NU for better contract terms.

In his deposition, Mr. Saintcross asserted that analysts on his staff were monitoring the market and that if there was a long-run purchase comparable to HQ, they would have known about it.[26] However, GMP has not provided

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[26]As discussed elsewhere in this testimony, GMP's focus on long-run purchases directly comparable to the HQ purchase crippled GMP's analysis.

any internal memoranda or reports that support his claims. The monitoring of the market may have been limited to staying in touch with the remaining respondents to GMP's 1988 RFP for qualifying facilities (Saintcross deposition (Exhibit____DPS-PLC-P-7) at 148–150).

**Q: Did the Company compile any information on long-term trends in market prices?**

A: No. According to Mr. Saintcross (deposition at 56), the Company simply did not contemplate any future market price reductions.

**Q: Would a more active tracking of market conditions have revealed significant changes in long-term trends?**

A: Yes. The clear signs in 1991 of long-term changes that were unfavorable to HQ include the following:

- The reduced market interest in CoGen Lime Rock indicated that the market value was lower than the price of Lime Rock.
- New York was backing out of its HQ contract.
- The New England and New York load forecasts were declining.
- A surplus capacity situation was building on the NEPOOL system.
- There were sharp reductions in NY avoided costs as shown in Exhibit____DPS-PLC-P-12.
- Fuel-price forecasts were falling.

**Q: How did the reduced market interest in CoGen Lime Rock indicate that the market value was less than the price of Lime Rock?**

A: The most likely explanation for the lack of interest in CoGen Lime Rock was that, given the low cost of oil and the plentiful power supply, CoGen Lime Rock (and most other NUGs) were not least-cost options.

**Q: How did GMP interpret CoGen's difficulty in selling its capacity?**

A: The Company interpreted the problems with getting CoGen Lime Rock capacity sold to other utilities as indicating that CoGen Lime Rock was simply a riskier resource than the HQ purchase.[27] (1991 IRP at 4-14 to 4-15)

**Q: Please describe New York's backing off from its HQ contract.**

A: In 1989, some New York utilities had signed a 1,000 MW contract (through the New York Power Authority, or NYPA) with HQ for twenty years of purchases starting in 1995 and 1996, at prices only slightly greater than those in the VJO contract. The drop-dead or final-lock-in date for this contract was originally set for December 1991.[28]

The New York utilities were finding that DSM was more successful than they had anticipated, that load growth was likely to be slower than previously expected, and that the HQ contract would raise New York's 1999 reserve margin to 42%.[29]

This trend was clear as early as April 1991, when the Long Island Lighting Company announced that it was reconsidering its planned purchase of to 218 MW. The mayor of New York City had also requested that the utilities serving city loads (Con Ed and NYPA) reconsider the contract. In June 1991, VJO Counsel Richard Saudek, in a letter to Pierre Bolduc of HQ,

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[27]The Company offers a complicated rationale for why other utilities would not be interested in CoGen Lime Rock in IR IBM 1-84. This discovery response essentially argues that there were a lot of NUG projects available, and CoGen Lime Rock was not a particularly good deal. Of course, if CoGen Lime Rock was not the least-cost alternative to HQ, GMP should have been looking for a better one.

[28]New York's regulatory approval process was very different from Vermont's, in part because of NYPA's role.

[29]Without HQ, the reserve margin would be only a couple points lower.

mentioned the likelihood of a delay in the New York lock-in date, and the likelihood that the Vermont Board would want similar treatment for the Vermont utilities. (The letter is included as Exhibit___DPS-PLC-P-13.)

Agreement on delaying the New York decision from December 1991 to November 1992 was announced in August 1991, within a couple days of the VJO lock-in decision (Electric Utility Week article on the NY-HQ deal, attached as Exhibit___DPS-PLC-P-14).

**Q: How should the changing situation in New York have affected GMP's view of the HQ contract and the lock-in decision?**

A: New York's reluctance to lock into its purchase from HQ should have influenced GMP in several ways:

- Since the HQ–New York sale was very similar to the HQ-VJO sale, New York's reluctance should have caused GMP to question what the New York utilities might know that it did not.
- One basis for New York's reluctance to lock in was that DSM was proving more successful than expected (Electric Utility Week (Exhibit___DPS-PLC-P-14)). With all planned DSM, the HQ contract would be surplus to the utilities' needs past 2007 (Exhibit___DPS-PLC-P-12, Table 4-1). Since GMP was obligated to pursue all cost-effective DSM, it should have very carefully re-examined the long-term DSM potential before agreeing to lock into the contract.
- If GMP believed that the New York utilities had resource options more attractive than those directly available to GMP, as GMP has suggested (IR DPS 1-341; Dutton Deposition (Exhibit___DPS-PLC-P-3) at 48,

93), it should have approached the New York utilities to determine their interest in medium- to long-term sales to GMP.

- New York's declining interest in the HQ purchase greatly reduced the danger of HQ finding a better deal than the VJO sale and canceling its sale to Vermont. By the same token, the reduced interest from New York should have improved Vermont's bargaining position with HQ.

**Q: How should the sharp reductions in NY avoided costs have affected GMP's planning?**

A: In 1992, GMP used the low New York long-run avoided costs (LRACs) to justify its choice of a lower fuel-price projection (Letter from John Saintcross to William Steinhurst, included as Exhibit____DPS-PLC-P-15). In 1991, the same information should similarly have reminded GMP that fuel prices were falling, and that monitoring fuel prices was important. In addition, the New York Power Pool estimates of LRACs (released August 30, 1991) were lower than the HQ contract and other resources GMP had been considering, through at least 2004, as shown in Exhibit____DPS-PLC-P-12. If GMP had sought out purchases from the New York utilities in this time period, it probably would have received some very attractive offers.

*2. Comparison of HQ to a Least-Cost Alternative*

**Q: Have you been able to determine what GMP's analyses would have indicated about the economics of the purchase immediately prior to the lock-in?**

A: We do not have a GMP run that directly compares a least-cost supply plan with HQ and a least-cost supply plan without HQ. The best I have been able to do is to start with GMP's comparison of 5 MW of HQ Schedule C3 to 5 MW of CoGen Lime Rock, and correct that case.

As I discussed above, replacing HQ with CoGen Lime Rock reduced CNPVRR through 2009. For most decisions in the IRP, GMP did not consider costs and benefits more than ten years from the start of a resource, which for HQ and CoGen would have implied a 2005 cut-off. However, GMP chose HQ over CoGen based on CNPVRR benefits to 2010 and 2015, and did not analyze further alternatives to HQ.

Yet GMP also found in the IRP that the NU intermediate purchase, followed by a gas combined-cycle (or "NU-NGCC"), would be less expensive than CoGen. For example, 30 MW of NU-NGCC produces a CNPVRR that is lower than the CoGen CNPVRR by $6 million in 2005 and $5 million in 2010 and 2015 (IR DPS 1-249). Replacing 5 MW of CoGen with 5 MW of NU-NGCC would thus be expected to save about $1.2 million in 2005 and $0.8 million in 2010 and 2015. Correcting GMP's frontloading of the NGCC capital costs would reduce CNPVRR by $0.4 million in 2010 and $0.5 million in 2015. In addition, the NU purchase apparently would have allowed GMP to purchase a MW or so of Northfield Mountain, worth roughly $0.5 million in CNPVRR. These results can be summarized as: follows:

**CNPVRR Differences for 5 MW (Base Fuel)**

Millions of nominal dollars

| | HQ Benefit over CoGen | NU-NGCC Benefit over CoGen | Correction for NGCC Capital Costs | Northfield Value | Total Benefit of NU-NGCC over HQ |
|---|---|---|---|---|---|
| 2005 | $0.56 | $1.0 | | $0.3 | $2.0 |
| 2010 | (0.06) | 0.8 | 0.4 | 0.3 | 1.4 |
| 2015 | (0.6) | 0.8 | 0.4 | 0.3 | 0.09 |

Had GMP compared the HQ contract to the NU-NGCC case, even under its base-case assumptions, it would evidently have found that at least a portion of its planned purchase were uneconomic. Had GMP corrected its methodology for capital costs and included the value of some Northfield capacity, those benefits would have been quite clear.

The information that a portion (and perhaps all) of GMP's HQ entitlement was not cost-effective, even at high fuel prices, would need to be disclosed to the Board in Docket No. 5330-A. GMP could not have reasonably voted for an early lock-in while it was still committed to a purchase that it had found to be uneconomic. This one simple analysis should have been enough to delay the lock-in.

*3. Economics of HQ with the Low-Fuel-Price Forecast*

**Q: How did GMP develop the low fuel-price forecast?**

A: Recognizing that the "base" fuel-price case was too high to be considered a base case, GMP developed a low fuel-price projection by combining the WEFA May 1991 short-term low-price forecast with the long-term low escalation rates from the WEFA 1990 forecast. This forecast was available to GMP at the time of the lock-in, and GMP conducted extensive analyses of DSM and non-HQ resources under low fuel prices in the IRP.

**Q: How did GMP use the low-fuel-price case?**

A: In the IRP itself, the low fuel case is presented as a sensitivity, used in the following two areas:

- All nine collaboratively designed DSM programs were screened with the avoided costs from the low-fuel-price case. Four of them failed. Nonetheless, all nine DSM programs were included in the IRP.

- The NU intermediate purchase, already selected as part of the resource plan, was compared to CoGen Lime Rock, short-term opportunity purchases, and various hypothetical extensions of the RG&E purchase. The preferred option varied with the length of the analysis, the fuel forecast, and load growth.

Since GMP did not choose to sign up for any of the NU capacity during the development of the IRP, or afterwards, it appears that the sensitivity may have caused GMP to be more cautious about commitment to resources that were not least-cost for low fuel prices. Unfortunately, GMP did not apply that standard to HQ.

It is clearer that the low-fuel-price case affected DSM planning. The IRP included all of the collaboratively designed DSM programs. Within six months of the filing of the IRP (and five months after the HQ lock-in deadline), GMP decided that the low-fuel-price was its best estimate. GMP then produced new avoided energy costs, using the low fuel-price projection and lower market energy prices, which led to the determination that four of the DSM programs were not cost-effective (4/30/92 memo in Exhibit____DPS-PLC-P-11).

**Q: In terms of fuel prices, what had changed between the time of the IRP analysis, in August 1991, and the April 1992 analysis?**

A: Interestingly, GMP had not received any additional fuel-price forecasts in this period (Saintcross deposition (Exhibit____DPS-PLC-P-7) at 53–54; IR DPS 1-233, 1-235). In the April 1992 memo conveying the new avoided energy costs, the only explanation for the change in the fuel-price forecast was that the avoided costs had been

> 1992 fossil-fuel prices for GMP's units were updated to current levels.... A set of low-fuel escalation scenario escalators were applied to the 1992 base fuel prices. These low escalators were the same as had been used in the low-fuel escalation sensitivity analysis in the October 1991 IRP.

In his September 21, 1992 letter to Dr. Steinhurst (at 2; letter included as Exhibit____DPS-PLC-P-15), Mr. Saintcross claimed that

> This forecast, absent any consideration of...continued economic decline and depressed fuel prices, is the same low forecast of fuel prices employed in the October 1991 IRP, which to date has not been challenged by parties to Docket No. 5270-GMP-4.

In other words, GMP believed that the IRP's low fuel-price forecast was the important forecast, at least for DSM, and the high "base" forecast was irrelevant.

**Q: Did GMP offer any justification for the changes in fuel prices from October 1991 to April 1992?**

A: In his letter to Dr. Steinhurst (Exhibit____DPS-PLC-P-15), Mr. Saintcross cited four factors to justify the reduction in fuel prices from the IRP to April 1992:

- "[T]he current...price of fuel" was lower than in 1991, and "short-term events will strongly influence the cost-effectiveness of ... any decision regarding power supply sources."
- "The May 1991 WEFA fuel price forecast was based on WEFA's March 1991 national macroeconomic forecast. At that time the impact of the Persian Gulf War was not known."
- "[T]he economy was expected to recover from a mild recession during the first half of 1991."
- "[T]he breakup of the Soviet Union and the prospects for free market access to Soviet oil reserves had not occurred."

These explanations are contrary to GMP's other positions and contemporaneous reality. The first point is in direct contradiction to Mr. Saintcross's position (in his deposition (Exhibit____DPS-PLC-P-7) at 50) that he did not bother changing fuel prices prior to the lock-in because various factors might work in different directions.

The second point does not explain the change in GMP's perspective on prices for gas, which actually fell during the Gulf war. In addition, the cash prices (as opposed to forecasts) of both gas and oil fell in the spring and summer of 1991 (before August 1991), not in the period from August 1991 to April 1992 (Exhibit____DPS-PLC-P-16).

The third point does not explain why GMP was not aware in August or October 1991 that the recession had not ended in the spring.[30] In addition, the slow-down on a national level was essentially over by the summer of 1991; Exhibit____DPS-PLC-P-17.

The fourth point is essentially irrelevant. Neither the May 1991 or August 1993 WEFA fuel price forecast (GMP did not order any 1992 fuel forecast) mentions the supply of Soviet or post-Soviet oil as being important to world prices. In addition, in 1991, the supply of Soviet fuel to the West was generally assumed to be limited by technical competence and investment, rather than politics ( Exhibit____DPS-PLC-P-18).

**Q: Did GMP compare its new, lower fuel-price forecast to any external fuel-price forecast?**

[30]Actually, WEFA predicted a "growth recession" ending in the third quarter of 1991, which was over before the IRP was filed.

A: No. In his letter to Dr. Steinhurst (Exhibit___DPS-PLC-P-15), Saintcross did compare GMP's avoided costs to those of New England Power (NEPCo) and the New York utilities, but did not compare fuel prices. Mr. Saintcross seemed to find considerable significance in the fact that GMP's revised avoided costs were still higher than those of NEPCo and New York. Of course, those utilities' low avoided costs were due, in part, to their excess capacity.

**Q: If GMP had compared its fuel prices to those used by NEPCo or the New York utilities in the summer of 1991, what would it have found?**

A: Both NEPCo and the New York utilities were projecting much lower fuel prices than was GMP, as shown in Exhibit___DPS-PLC-P-19. Indeed, NEPCo's 1991 base-case fuel-cost projections were lower than GMP's low case. Their estimates of avoided costs were also much lower than GMP's in the summer of 1991. It is unfortunate that GMP chose to look to these utilities only after the lock-in of the HQ contract.

**Q: How was the low-fuel-price sensitivity analysis used in GMP's decision to lock in the HQ contract?**

A: There is no evidence that the sensitivity analysis was considered at all in the lock-in decision. The 1991 IRP contains no discussion of the cost-effectiveness of HQ under low-fuel-price (or low-load) conditions. Low fuel prices are applied only to DSM and intermediate supply options.

**Q: Did GMP examine the effect of the low-fuel-price forecast to the HQ purchase?**

A: The Company may not have even performed any low-fuel sensitivities of HQ economics before the early lock-in. The box of IRP workpapers contains limited summaries of two sets of additional UPLAN runs assuming a supply plan that does not contain Schedule C3. Both of these analyses use the low fuel-price forecast GMP developed shortly before the lock-in, and neither is mentioned in the IRP. The box of workpapers also provides the power supply costs for the IRP resource plan in the low fuel case, which can be compared to the no-HQ case.

Since these cases are not listed or discussed in the IRP, we do not know whether they were run before or after the lock-in. They are dated in early September, but Mr. Saintcross has pointed out that these dates may represent the date on which the archive version was printed, rather than the date the results were first available. In any case, these cases should have been run prior to the lock-in, since the low fuel-price forecast was available for the IRP, and essentially all the IRP computations were completed prior to the lock-in (Saintcross deposition (Exhibit____DPS-PLC-P-7) at 28–29, 58–59; Dutton deposition (Exhibit____DPS-PLC-P-3) at 80).

**Q: Did the two plans without Schedule C3 contain the best resources to compare to HQ with low fuel?**

A: No. Any comparison of the low-fuel price cases is likely to be biased against the non-HQ alternative plans, because they are not optimized supply plans. One plan replaces Schedule C3 with the NU base–IGCC combination, the other with WESNEEX.

The Company acknowledged that its low-fuel-price sensitivity analysis does not provide a reliable cost-benefit analysis of HQ after the date of a new capacity addition:

> If an actual low-fuel scenario continued to stretch out that far, we doubtlessly would re-optimize accordingly. We agreed with this, suggesting that a proper use of [the low fuel sensitivity case] would be to look at fuel sensitivities from the present out to the time of the first addition of a new unit-specific, non-embedded resource.
>
> In retrospect, we certainly knew the pitfalls of relying on a fuel sensitivity case beyond the intermediate term and probably should either have limited the term of the analyses or offered a caveat similar to that provided in the 1989 IRP's uncertainty analysis. In any event, this constitutes only a semantic omission—GMP would not have placed long-term reliance on such studies. (2/19/92 Baslow memo (in Exhibit____DPS-PLC-P-11) at 11)

In other words, GMP knew that it would need to re-examine its supply alternatives before making meaningful comparisons under low fuel prices. Unfortunately, GMP failed to do so in reviewing the HQ purchase.

**Q: What resources should GMP have compared to HQ for the low fuel-price case?**

A: Rather than using the NU Base purchase, followed by an IGCC, GMP should have compared HQ to a purchase of NU intermediate capacity, followed by a natural-gas combined-cycle plant. The oil-fired NU intermediate purchase is about 8% less expensive than the mostly nuclear NU base purchase for the low fuel case, even if the intermediate oil units were required to operate at the 70% capacity factor GMP assumed for the base purchase. Indeed, the cost of the intermediate purchase is essentially equivalent to that of the base purchase, even with the base fuel forecast.

The natural-gas combined-cycle plant is similarly significantly less expensive than the IGCC, for low fuel prices.

**Q: What should GMP have concluded if it had compared the HQ purchase to a least-cost alternative without HQ, with its low fuel prices?**

A: With these low fuel prices, the present value of revenue requirements would be lower with the NU intermediate purchase, followed by a gas-fired combined-cycle, than with Schedule C3. Other resources (e.g., purchases from New York) might have been even less expensive.

### *E. The Premature August Lock-in Decision*

**Q: Please describe the circumstances of the August lock-in decision.**

A: The lock-in decision was made with unseemly haste: through a 10-A.M. "hastily called" telephone conference call with notice by fax only the day before (Exhibit___DPS-PLC-P-20). The participants were provided no written explanation of the decision and no analysis of the advantages and disadvantages of an early lock-in, and no substantive discussion occurred among the participants.

**Q: Was there any significance to the date of the lock-in?**

A: The lock-in came some two weeks before the Board requirement for a filing of any additional Contract amendments. It also coincided with the announcement of an 11-month delay in New York's decision on locking in its own 1,000-MW contract. That contract had been in trouble for some time, as New York load forecasts fell and NUG purchases rose (Electric Utility Week (Exhibit___DPS-PLC-P-14)).

**Q: Could GMP have prevented the early lock-in?**

A: Yes. If GMP had opposed the early lock-in, and discussed the results of its cost-effectiveness analysis with the other participants, it is unlikely that the Joint Owners would have voted to lock in early, for three reasons. First, GMP was one of the two original proposers and negotiators of the contract, as well as the second-largest participant, with about a third of the capacity.

Second, proceeding to an unnecessary early lock-in, in the face of unfavorable news, would have exposed participants to prudence reviews. Third, most of the other participants had opted for delivery of HQ power in the early 1990s, when it would clearly be even less cost-effective than in 1995, when GMP's purchases were to start.

**Q: What did GMP give up when it agreed to an early lock-in?**

A: The Company gave up the benefits of delaying the final decision and an opportunity to negotiate better contract terms in exchange for its agreement to lock-in.

**Q: Before the lock-in, did GMP analyze the benefits of delaying the decision?**

A: No.

**Q: Did GMP recognize in other circumstances that delay had benefits?**

A: Yes. GMP recognized the value of delay earlier in 1991:

> We had time to decide on Hydro-Quebec, therefore, we had time to get new information to evaluate the value of entering into that contract. (Saintcross deposition at 47)

> It just so happens we have time now to evaluate Hydro-Quebec ... so it made sense for us to go back and say; okay what does the market look like now? We always update our assumptions as much as we possibly can. (ibid. at 48)

The Company should have realized that the value of delay was enhanced by the facts that forecasts of market conditions were changing in a direction that was unfavorable to HQ (Saintcross deposition at 59–60), and that forecasts could fall further (Saintcross deposition at 61). Unfortunately, GMP did not recognize that it would benefit from delaying the decision or gathering more information in the rapidly changing environment in August 1991.

**Q: Did the Company consider that further delay past August 28, 1991 had value?**

A: No. In the Company's view, nothing was likely to happen before December 1991 that would change its decision to purchase from Hydro-Quebec (Saintcross deposition (Exhibit____DPS-PLC-P-7) at 49–50, 62–63).

**Q: Did GMP give any consideration to renegotiating the Contract in exchange for its agreement to lock-in early?**

A: No. GMP did not attempt to renegotiate its allocation or obtain any other consideration whatsoever in exchange for its agreement to lock into the Contract (DPS 1-231, 2-28). In particular, it made no attempt to negotiate revisions in the front-end-loaded price in exchange for locking into the Contract early, even though this pricing structure was of serious concern to the Joint Owners (DPS 1-335 and 336).

**Q: Then what was the basis for GMP's decision to lock-in early?**

A: The potential cost of delay was that that HQ might back out of the contract, and that the contract would turn out to be cost-effective. However, HQ was unlikely to want to back out of the VJO contract in a declining market and with its only other customer (New York) backing away from a commitment. Hydro Quebec essentially had nowhere else to go.[31] In addition, had GMP

[31]Hydro-Quebec agreed to waive Condition 10 as a basis for terminating the Contract without paying damages, in order to secure the Joint Owners' agreement to lock in the Contract in August. Since it had no other customers for the power, and since the potential down-side to HQ from Condition 10 seems small (presumably paying the cost of replacing the power at market prices, in exchange for withdrawing its own supply, which could be resold at market

performed a good analysis of the HQ contract, it would have realized by then that the contract was marginal, at best, so the damages from termination would have been small or zero.

A more important consideration was that GMP seems to have been overly focused on finalizing the contract. The Company had decided long before that the HQ purchase was cost-effective (IR DPS 1-335) and had not looked very carefully at the decision since. In its view, the only obstacle to signing the contract was the disagreement with HQ over liability in the event of cancellation of the contract (IR DPS 1-231, 2-28, 1-334, 1-335):

> [T]he Company's objective in securing the lock-in was to ensure the availability of the benefits of the VJO Contract notwithstanding the potential uncertainties associated with condition No. 10.... When this uncertainty was resolved, the parties "locked into" the Contract. (IR DPS 1-231)

Finally, the Joint Owners (and presumably GMP) were concerned that any further delay or changes to the Contract would open the purchase decision to another Board review. In a June 4, 1991 letter to Pierre Bolduc of HQ regarding the possibility of another extension beyond November 30, 1991 (included as Exhibit____DPS-PLC-P-13), Richard H. Saudek, counsel for the Joint Owners expressed the following concern:

> If we go forward with [a further extension], there is little doubt the Board will revisit fundamental issues relating to the Contract. There is also no question that there will be new media attention focused on Hydro-Quebec's problems.

Indeed, in rejecting Amendment #3, the Board found that it raised significant substantive issues, which would require detailed Board review (Docket No.

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prices), HQ was likely to waive Condition 10 in November or whenever it could get the VJO to lock in.

5330-E, Order of 4/22/91 at 2).[32] The Joint Owners rather than renegotiating the Contract to reduce costs to ratepayers sought to complete the lock-in without further regulatory review of the contract.

It was imprudent of GMP to make a hasty commitment to a contract that it knew or should have known was economically doubtful. That imprudence would be compounded if the haste were motivated by an unwise reluctance to submit to the Board's regulatory authority.

## V. The Consequences of the Early Lock-In on GMP's Resource Planning

**Q: What would have happened to the HQ-VJO contract if the participants had delayed the lock-in decision from late August to the end of November, and used the intervening three months to continue analyzing their options?**

A: If the participants had prudently analyzed the costs and benefits of the HQ contract, they would have almost certainly rejected the contract as it then existed. The Burlington Electric Department had already determined that its HQ share was not cost-effective, and confirmed the same result for Washington Electric Cooperative's share in September (as shown in Exhibit___DPS-PLC-P-8). If the GMP low-fuel-price analyses had not been completed in August, they certainly could have been performed before the end of November. Since the low-fuel-price forecast became GMP's base forecast within a few months, without GMP having received any new fuel

[32]The Board also expressed concern that the proposed amendment did not allow the Joint Owners "to terminate the contract without liability if they find an opportunity to buy equivalent power at a cheaper price within the deferral year" (ibid. at 5).

price projections, GMP should have been giving greater weight to the low-fuel cases as time passed.

Most of the VJO participants were purchasing Schedule C power earlier than GMP was. The HQ power was less competitive in the early 1990s, when market purchases were particularly attractive, due to low fuel prices and large regional capacity surpluses.

If the participants were unwilling to cancel the contract by the end of November, prudent analysis of the contract economics should at least have lead the Joint Owners to seek to extend the lock-in deadline, perhaps to the April 30, 1992 date proposed in Amendment 3. As VJO Representative Saudek observed in his letter to HQ (Exhibit___DPS-PLC-P-13)), any further delay in the deadline was likely to trigger a reopening of the Board's analysis of the contract. The Board might also have forced this issue on CVPS in Docket 5491, a rate case that was pending in August 1991, had the lock-in not mooted further proceedings.

The avoidance of the lock-in in August would almost certainly have led to cancellation or major modifications of the contract, either prior to the November deadline or in a subsequent extension. By early 1992, even GMP knew that the Contract was uneconomic:

> In early 1992, the Company began seeing indications of the difficulties in selling wholesale on a competitive basis into certain parts of New England. (IR DPS 1-296)

**Q: What might those modifications have included?**

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 costs of new GT and CC 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-Quebec did not seem inclined to move quickly on any major price reductions.

## VI. The Effect of the Decision to Accept the HQ Contract on Current Costs

**Q: How much lower would GMP's power costs be today if it, or the Joint Owners as a whole, had not locked into the HQ contract?**

A: That would depend on what actions GMP, the Joint Owners, and HQ would have taken after August 1991, had GMP and the Joint Owners not agreed to the premature August lock-in. The continuing decline in load forecasts, fuel-price forecasts, and market power costs, plus likely re-examination of the contract by the Board, would probably have led to either the termination of Schedules B and C, or to steep reductions in the prices.

In the event of termination, GMP 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 GMP would have been able to contract for such a purchase and get it approved before falling market prices rendered it uneconomic. GMP would more likely have purchased power primarily on the short- and medium-term market. As a result, the cost of GMP's replacement power for HQ would probably have been close to the market value of that power, which GMP estimates to be $21.9 million less than the cost of the purchase in 1998 for its preferred "Alternate Low Market Price" (IR DPS 2-54). With GMP's market-price estimates, the annual excess cost of HQ actually rises over time. I believe that market prices will be higher, and the excess cost of the HQ contract lower, than GMP's projection. The "DPS Mid Market Price" table in IR DPS 2-54 reports an excess cost for the HQ purchase in 1998 of $16.7 million, at a more likely market price of $32.1/MWh. In the Mid Market case, the excess costs rise in 1999 and 2000, then fall gradually, but remain over $10 million annually through 2012.

**Q: Were any New England utilities net purchasers of power in the early 1990s?**

A: Yes. Some of the other Vermont utilities, such as Burlington Electric, rejected their HQ elections, or have been otherwise short on capacity since 1991. Unitil has also needed to acquire additional power supply in this period. These utilities have generally purchased power in the short and medium term, essentially at market prices.

Most or all of the above-market costs of the HQ purchase could have been avoided had GMP and the Joint Owners chosen not to lock into the HQ contract early.

## VII. Conclusions and Recommendations

**Q: Please summarize your conclusions on the prudence of GMP's purchase from HQ.**

A: The Company was imprudent in the negotiation of the contract, in failing to structure the contract to allow the Board to reject the purchases of particular schedules, or by particular utilities, without voiding the entire contract.

The Company was imprudent in its analyses during 1991 in

- violating the Board's order to prepare an alternative plan in the event that the HQ contract was terminated.
- using criteria for analyzing HQ that were substantially less rigorous than those used in analyzing DSM.
- failing to monitor prudently changing conditions in the markets for power and fuels.
- failing to maintain adequate communication within the Company to support the HQ contract decision, including clear assignments to staff analysts, regular written reports to management, queries and instructions from management to staff, or presentations to the Board of Directors.
- failing to document the data-gathering and decision-making processes.
- failing to construct a least-cost plan for comparison with HQ.

- failing to identify issues, inputs, and trends that were critical to the cost-effectiveness of the purchase.
- failing to review the cost-effectiveness of HQ with the low fuel-price forecast.
- biasing analyses toward HQ by pricing out GMP-owned alternatives with their front-loaded annual revenue requirements, without accounting for end effects.
- comparing HQ to a coal-fired combined-cycle plant, rather than a less-expensive gas-fired combined-cycle plant.
- using the predominantly nuclear NU base purchase rather the oil-based intermediate purchase, especially when low fuel prices were assumed.
- comparing HQ to CoGen Lime Rock rather than the less expensive NU intermediate purchase, followed by a gas combined-cycle.
- ignoring the benefits of the Northfield Mountain pumped-storage plant as part of an NU purchase.
- failing to analyze the costs and benefits of the early lock-in.
- failing to update the economic analysis of the HQ contract prior to the lock-in decision.

**Q: Does this conclude your testimony on the prudence of GMP's purchase from HQ?**

A: Yes, at this time.

# Exhibit DPS-PLC-7:
# Comparison of 1991-1992 Fuel-Price Forecasts

***Escalation in #6 Oil Price:***

| | Cumulative Nominal Escalation in #6 Oil Price | | | | Cumulative Real Escalation in #6 Oil Price | | | |
|---|---|---|---|---|---|---|---|---|
| | 5/91 WEFA | 91-92 WEFA | 1992 WEFA | GMP "Low" | 5/91 WEFA | 91-92 WEFA | 1992 WEFA | GMP "Low" |
| 1990 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| 1991 | 0.85 | 0.82 | 0.79 | 0.85 | 0.83 | 0.79 | 0.76 | 0.83 |
| 1992 | 0.89 | 0.82 | 0.76 | 0.85 | 0.84 | 0.77 | 0.71 | 0.80 |
| 1993 | 0.97 | 0.89 | 0.83 | 0.92 | 0.88 | 0.82 | 0.75 | 0.84 |
| 1994 | 1.04 | 0.96 | 0.89 | 0.97 | 0.92 | 0.85 | 0.79 | 0.86 |
| 1995 | 1.13 | 1.04 | 0.95 | 1.03 | 0.96 | 0.88 | 0.81 | 0.87 |
| 1996 | 1.24 | 1.10 | 0.96 | 1.08 | 1.01 | 0.90 | 0.79 | 0.88 |
| 1997 | 1.37 | 1.16 | 0.97 | 1.14 | 1.07 | 0.92 | 0.78 | 0.89 |
| 1998 | 1.50 | 1.22 | 0.99 | 1.20 | 1.13 | 0.93 | 0.76 | 0.90 |
| 1999 | 1.65 | 1.32 | 1.05 | 1.27 | 1.18 | 0.97 | 0.79 | 0.91 |
| 2000 | 1.80 | 1.43 | 1.13 | 1.34 | 1.24 | 1.01 | 0.81 | 0.92 |
| 2001 | 1.95 | 1.55 | 1.23 | 1.41 | 1.28 | 1.05 | 0.86 | 0.93 |
| 2002 | 2.11 | 1.68 | 1.33 | 1.48 | 1.34 | 1.10 | 0.89 | 0.94 |
| 2003 | 2.26 | 1.80 | 1.42 | 1.56 | 1.38 | 1.13 | 0.92 | 0.95 |
| 2004 | 2.43 | 1.93 | 1.52 | 1.65 | 1.42 | 1.17 | 0.95 | 0.97 |
| 2005 | 2.60 | 2.06 | 1.61 | 1.74 | 1.47 | 1.20 | 0.98 | 0.98 |
| 2006 | 2.78 | 2.20 | 1.72 | 1.83 | 1.51 | 1.24 | 1.01 | 1.00 |
| 2007 | 2.97 | 2.34 | 1.83 | 1.93 | 1.55 | 1.27 | 1.03 | 1.01 |
| 2008 | 3.15 | 2.48 | 1.94 | 2.03 | 1.59 | 1.30 | 1.06 | 1.02 |
| 2009 | 3.36 | 2.64 | 2.06 | 2.14 | 1.62 | 1.33 | 1.09 | 1.04 |
| 2010 | 3.56 | 2.80 | 2.18 | 2.26 | 1.66 | 1.36 | 1.11 | 1.05 |
| 2011 | 3.76 | 2.97 | 2.32 | 2.38 | 1.68 | 1.39 | 1.14 | 1.07 |
| 2012 | 3.95 | 3.12 | 2.45 | 2.51 | 1.70 | 1.42 | 1.17 | 1.08 |
| 2013 | 4.15 | 3.30 | 2.60 | 2.65 | 1.72 | 1.44 | 1.19 | 1.10 |
| 2014 | 4.37 | 3.48 | 2.75 | 2.79 | 1.74 | 1.47 | 1.22 | 1.11 |
| 2015 | 4.59 | 3.67 | 2.91 | 2.94 | 1.76 | 1.49 | 1.25 | 1.13 |

# Exhibit DPS-PLC-7:
# Comparison of 1991-1992 Fuel-Price Forecasts

***Escalation in #2 Oil Price:***

| | Cumulative Nominal Escalation in #2 Oil Price | | | | Cumulative Real Escalation in #2 Oil Price | | | |
|---|---|---|---|---|---|---|---|---|
| | 5/91 WEFA | 91-92 WEFA | 1992 WEFA | GMP "Low" | 5/91 WEFA | 91-92 WEFA | 1992 WEFA | GMP "Low" |
| 1990 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| 1991 | 0.82 | 0.91 | 0.88 | 0.82 | 0.80 | 0.88 | 0.85 | 0.80 |
| 1992 | 0.82 | 0.90 | 0.82 | 0.77 | 0.77 | 0.85 | 0.77 | 0.73 |
| 1993 | 0.87 | 0.93 | 0.87 | 0.82 | 0.80 | 0.85 | 0.79 | 0.75 |
| 1994 | 0.92 | 0.97 | 0.93 | 0.85 | 0.81 | 0.86 | 0.82 | 0.75 |
| 1995 | 0.99 | 1.03 | 0.98 | 0.89 | 0.84 | 0.88 | 0.84 | 0.76 |
| 1996 | 1.07 | 1.10 | 0.99 | 0.93 | 0.87 | 0.90 | 0.82 | 0.76 |
| 1997 | 1.18 | 1.18 | 1.00 | 0.97 | 0.92 | 0.93 | 0.80 | 0.76 |
| 1998 | 1.28 | 1.27 | 1.02 | 1.02 | 0.96 | 0.96 | 0.79 | 0.76 |
| 1999 | 1.39 | 1.36 | 1.07 | 1.06 | 1.00 | 0.99 | 0.80 | 0.76 |
| 2000 | 1.50 | 1.46 | 1.13 | 1.11 | 1.03 | 1.03 | 0.82 | 0.76 |
| 2001 | 1.62 | 1.55 | 1.21 | 1.16 | 1.07 | 1.05 | 0.84 | 0.77 |
| 2002 | 1.74 | 1.66 | 1.27 | 1.21 | 1.10 | 1.08 | 0.86 | 0.77 |
| 2003 | 1.86 | 1.75 | 1.35 | 1.27 | 1.13 | 1.10 | 0.88 | 0.77 |
| 2004 | 1.99 | 1.85 | 1.43 | 1.33 | 1.17 | 1.12 | 0.90 | 0.78 |
| 2005 | 2.12 | 1.95 | 1.51 | 1.38 | 1.20 | 1.14 | 0.92 | 0.78 |
| 2006 | 2.26 | 2.06 | 1.60 | 1.45 | 1.23 | 1.16 | 0.93 | 0.79 |
| 2007 | 2.41 | 2.17 | 1.68 | 1.51 | 1.26 | 1.18 | 0.95 | 0.79 |
| 2008 | 2.57 | 2.27 | 1.77 | 1.58 | 1.29 | 1.19 | 0.97 | 0.79 |
| 2009 | 2.73 | 2.37 | 1.87 | 1.65 | 1.32 | 1.20 | 0.99 | 0.80 |
| 2010 | 2.90 | 2.46 | 1.98 | 1.73 | 1.35 | 1.20 | 1.01 | 0.80 |
| 2011 | 3.05 | 2.58 | 2.08 | 1.80 | 1.37 | 1.21 | 1.03 | 0.81 |
| 2012 | 3.22 | 2.70 | 2.19 | 1.88 | 1.39 | 1.22 | 1.04 | 0.81 |
| 2013 | 3.38 | 2.83 | 2.31 | 1.97 | 1.40 | 1.24 | 1.06 | 0.82 |
| 2014 | 3.56 | 2.96 | 2.43 | 2.06 | 1.42 | 1.25 | 1.08 | 0.82 |
| 2015 | 3.74 | 3.10 | 2.56 | 2.15 | 1.43 | 1.26 | 1.10 | 0.82 |

# Exhibit DPS-PLC-7:
# Comparison of 1991-1992 Fuel-Price Forecasts

***Escalation in Interruptible Gas Price:***

| | Cumulative Nominal Escalation in Price of Interruptible Gas delivered to Stonybrook | | | | Cumulative Real Escalation in Price of Interruptible Gas delivered to Stonybrook | | | |
|---|---|---|---|---|---|---|---|---|
| | 5/91 WEFA | 91-92 WEFA | 1992 WEFA | GMP "Low" | 5/91 WEFA | 91-92 WEFA | 1992 WEFA | GMP "Low" |
| 1990 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| 1991 | 0.92 | 0.87 | 0.83 | 0.92 | 0.90 | 0.84 | 0.79 | 0.90 |
| 1992 | 0.95 | 0.92 | 0.89 | 0.93 | 0.90 | 0.86 | 0.83 | 0.88 |
| 1993 | 1.08 | 1.01 | 0.93 | 1.00 | 0.99 | 0.92 | 0.85 | 0.91 |
| 1994 | 1.20 | 1.09 | 0.99 | 1.06 | 1.06 | 0.96 | 0.87 | 0.94 |
| 1995 | 1.35 | 1.19 | 1.04 | 1.14 | 1.14 | 1.01 | 0.89 | 0.96 |
| 1996 | 1.47 | 1.28 | 1.10 | 1.21 | 1.20 | 1.05 | 0.91 | 0.99 |
| 1997 | 1.61 | 1.38 | 1.18 | 1.30 | 1.26 | 1.09 | 0.94 | 1.01 |
| 1998 | 1.75 | 1.49 | 1.25 | 1.38 | 1.31 | 1.13 | 0.96 | 1.04 |
| 1999 | 1.91 | 1.60 | 1.34 | 1.48 | 1.37 | 1.17 | 1.00 | 1.06 |
| 2000 | 2.07 | 1.73 | 1.43 | 1.58 | 1.43 | 1.22 | 1.03 | 1.09 |
| 2001 | 2.24 | 1.86 | 1.54 | 1.69 | 1.48 | 1.26 | 1.07 | 1.11 |
| 2002 | 2.46 | 2.02 | 1.65 | 1.80 | 1.56 | 1.32 | 1.11 | 1.14 |
| 2003 | 2.68 | 2.19 | 1.77 | 1.92 | 1.64 | 1.38 | 1.15 | 1.17 |
| 2004 | 2.91 | 2.36 | 1.90 | 2.05 | 1.71 | 1.43 | 1.19 | 1.21 |
| 2005 | 3.14 | 2.54 | 2.04 | 2.19 | 1.77 | 1.48 | 1.23 | 1.24 |
| 2006 | 3.37 | 2.72 | 2.17 | 2.34 | 1.83 | 1.53 | 1.27 | 1.27 |
| 2007 | 3.62 | 2.91 | 2.32 | 2.50 | 1.89 | 1.58 | 1.31 | 1.31 |
| 2008 | 3.89 | 3.11 | 2.46 | 2.67 | 1.95 | 1.63 | 1.35 | 1.34 |
| 2009 | 4.17 | 3.32 | 2.63 | 2.85 | 2.02 | 1.68 | 1.39 | 1.38 |
| 2010 | 4.48 | 3.55 | 2.80 | 3.05 | 2.08 | 1.73 | 1.43 | 1.42 |
| 2011 | 4.76 | 3.78 | 2.98 | 3.26 | 2.13 | 1.77 | 1.47 | 1.46 |
| 2012 | 5.04 | 4.00 | 3.16 | 3.48 | 2.17 | 1.81 | 1.50 | 1.50 |
| 2013 | 5.31 | 4.24 | 3.36 | 3.71 | 2.20 | 1.85 | 1.54 | 1.54 |
| 2014 | 5.60 | 4.49 | 3.57 | 3.97 | 2.23 | 1.89 | 1.59 | 1.58 |
| 2015 | 5.90 | 4.74 | 3.79 | 4.24 | 2.26 | 1.93 | 1.63 | 1.62 |

# Exhibit DPS-PLC-7:
# Comparison of 1991-1992 Fuel-Price Forecasts

***Inflation Indices:***

| | Cumulative GNPIPD Index | | | | Cumulative CCI Index | | | |
|---|---|---|---|---|---|---|---|---|
| | 5/91 WEFA | 91-92 WEFA | 1992 WEFA | GMP "Low" | 5/91 WEFA | 91-92 WEFA | 1992 WEFA | GMP "Low" |
| 1990 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| 1991 | 1.03 | 1.04 | 1.04 | 1.03 | 1.02 | 1.02 | 1.02 | 1.02 |
| 1992 | 1.06 | 1.06 | 1.07 | 1.06 | 1.04 | 1.04 | 1.04 | 1.04 |
| 1993 | 1.10 | 1.10 | 1.10 | 1.10 | 1.08 | 1.07 | 1.06 | 1.08 |
| 1994 | 1.13 | 1.13 | 1.13 | 1.13 | 1.12 | 1.10 | 1.09 | 1.12 |
| 1995 | 1.18 | 1.17 | 1.17 | 1.18 | 1.17 | 1.14 | 1.12 | 1.17 |
| 1996 | 1.23 | 1.22 | 1.21 | 1.23 | 1.22 | 1.19 | 1.16 | 1.22 |
| 1997 | 1.28 | 1.27 | 1.25 | 1.28 | 1.27 | 1.24 | 1.20 | 1.27 |
| 1998 | 1.33 | 1.32 | 1.30 | 1.33 | 1.33 | 1.29 | 1.25 | 1.33 |
| 1999 | 1.39 | 1.37 | 1.34 | 1.39 | 1.39 | 1.34 | 1.29 | 1.39 |
| 2000 | 1.45 | 1.42 | 1.39 | 1.45 | 1.46 | 1.40 | 1.34 | 1.46 |
| 2001 | 1.52 | 1.48 | 1.44 | 1.52 | 1.53 | 1.46 | 1.40 | 1.53 |
| 2002 | 1.58 | 1.53 | 1.49 | 1.58 | 1.60 | 1.52 | 1.45 | 1.60 |
| 2003 | 1.64 | 1.59 | 1.54 | 1.64 | 1.67 | 1.59 | 1.51 | 1.67 |
| 2004 | 1.70 | 1.65 | 1.59 | 1.70 | 1.75 | 1.65 | 1.57 | 1.75 |
| 2005 | 1.77 | 1.71 | 1.65 | 1.77 | 1.82 | 1.72 | 1.63 | 1.82 |
| 2006 | 1.84 | 1.77 | 1.71 | 1.84 | 1.90 | 1.79 | 1.69 | 1.90 |
| 2007 | 1.91 | 1.84 | 1.77 | 1.91 | 1.99 | 1.87 | 1.76 | 1.99 |
| 2008 | 1.99 | 1.91 | 1.83 | 1.99 | 2.07 | 1.95 | 1.83 | 2.07 |
| 2009 | 2.07 | 1.98 | 1.89 | 2.07 | 2.16 | 2.03 | 1.90 | 2.16 |
| 2010 | 2.15 | 2.05 | 1.96 | 2.15 | 2.26 | 2.11 | 1.98 | 2.26 |
| 2011 | 2.23 | 2.13 | 2.03 | 2.23 | 2.36 | 2.20 | 2.06 | 2.36 |
| 2012 | 2.32 | 2.21 | 2.10 | 2.32 | 2.46 | 2.29 | 2.14 | 2.46 |
| 2013 | 2.41 | 2.29 | 2.17 | 2.41 | 2.57 | 2.39 | 2.22 | 2.57 |
| 2014 | 2.51 | 2.38 | 2.25 | 2.51 | 2.68 | 2.49 | 2.31 | 2.68 |
| 2015 | 2.61 | 2.46 | 2.33 | 2.61 | 2.80 | 2.59 | 2.40 | 2.80 |

Pre-DSM 46 MW HQ C3 vs 46 MW NU Base/2006 Coal

| | GMP estimate of pre-DSM plan with C3 ($M) | GMP estimate of system Base rev req ($M) | diff | rev req for 46 MW of IGCC | ECC for 46 MW of NGCC | IGCC rev req vs. NGCC ECC diff |
|---|---|---|---|---|---|---|
| 1990 | - | - | | | | |
| 1991 | 80.191 | 80.191 | 0.000 | - | - | - |
| 1992 | 91.595 | 91.595 | 0.000 | - | - | - |
| 1993 | 98.939 | 98.939 | 0.000 | - | - | - |
| 1994 | 101.433 | 101.433 | 0.000 | - | - | - |
| 1995 | 118.875 | 118.638 | -0.237 | - | - | - |
| 1996 | 145.677 | 145.766 | 0.089 | - | - | - |
| 1997 | 142.999 | 144.460 | 1.461 | - | - | - |
| 1998 | 167.743 | 165.068 | -2.675 | - | - | - |
| 1999 | 176.163 | 178.613 | 2.450 | - | - | - |
| 2000 | 170.919 | 175.467 | 4.548 | - | - | - |
| 2001 | 197.693 | 204.293 | 6.600 | - | - | - |
| 2002 | 209.269 | 222.572 | 13.303 | - | - | - |
| 2003 | 203.850 | 219.845 | 15.995 | - | - | - |
| 2004 | 235.719 | 246.774 | 11.055 | - | - | - |
| 2005 | 247.303 | 261.688 | 14.385 | - | - | - |
| 2006 | 239.014 | 276.761 | 37.747 | 55.47 | 35.20 | 20.27 |
| 2007 | 275.369 | 311.303 | 35.934 | 55.14 | 37.39 | 17.75 |
| 2008 | 291.305 | 325.455 | 34.150 | 54.66 | 39.69 | 14.97 |
| 2009 | 279.941 | 312.800 | 32.859 | 54.20 | 42.03 | 12.17 |
| 2010 | 323.543 | 354.779 | 31.236 | 53.97 | 44.55 | 9.43 |
| 2011 | 329.280 | 359.356 | 30.076 | 53.81 | 46.96 | 6.85 |
| 2012 | 553.398 | 581.121 | 27.723 | 53.68 | 49.38 | 4.30 |
| 2013 | 588.839 | 615.372 | 26.533 | 53.61 | 51.80 | 1.80 |
| 2014 | 616.516 | 641.523 | 25.007 | 53.77 | 54.38 | (0.61) |
| 2015 | 678.064 | 689.529 | 11.465 | 53.80 | 57.07 | (3.28) |
| | | | | **63.71** | **51.25** | **12.46** |

| Cumul. NPVRR $M | | | Diff btwn 46 MW C3 and no C3 Base | IGCC vs NGCC ECC diff | Revised estimate of diff between HQ C3 plan and Base No C3 | |
|---|---|---|---|---|---|---|
| 1991 | 72.062 | 72.062 | 0.000 | - | - | |
| 1992 | 146.029 | 146.029 | 0.000 | - | - | |
| 1993 | 217.828 | 217.828 | 0.000 | - | - | |
| 1994 | 283.975 | 283.975 | 0.000 | - | - | |
| 1995 | 353.638 | 353.500 | -0.139 | - | (0.139) | |
| 1996 | 430.355 | 430.263 | -0.092 | - | (0.092) | |
| 1997 | 498.028 | 498.627 | 0.599 | - | 0.599 | |
| 1998 | 569.363 | 568.825 | -0.538 | - | (0.538) | |
| 1999 | 636.686 | 637.084 | 0.398 | - | 0.398 | |
| 2000 | 695.383 | 697.343 | 1.960 | - | 1.960 | |
| 2001 | 756.394 | 760.390 | 3.997 | - | 3.997 | |
| 2002 | 814.430 | 822.116 | 7.686 | - | 7.686 | |
| 2003 | 865.233 | 876.905 | 11.672 | - | 11.672 | |
| 2004 | 918.023 | 932.171 | 14.148 | - | 14.148 | |
| 2005 | 967.794 | 984.837 | 17.043 | - | 17.043 | |
| 2006 | 1011.020 | 1034.890 | 23.870 | 3.666 | 20.204 | |
| 2007 | 1055.773 | 1085.483 | 29.710 | 6.551 | 23.159 | |
| 2008 | 1098.317 | 1133.015 | 34.697 | 8.738 | 25.959 | |
| 2009 | 1135.058 | 1174.068 | 39.010 | 10.336 | 28.674 | |
| 2010 | 1173.216 | 1215.910 | 42.694 | 11.447 | 31.246 | |
| 2011 | 1208.114 | 1253.996 | 45.881 | 12.173 | 33.708 | |
| 2012 | 1260.821 | 1309.342 | 48.522 | 12.583 | 35.939 | |
| 2013 | 1311.217 | 1362.010 | 50.793 | 12.737 | 38.055 | |
| 2014 | 1358.634 | 1411.350 | 52.716 | 12.690 | 40.025 | |
| 2015 | 1405.499 | 1459.007 | **53.508** | 12.464 | **41.044** | 2.92% |

**Comparison of Pre-DSM revenue Requirements:**
**46 MW HQ C3 vs 46 MW NU Base/2006 Coal**

| | HQ C3 ($M) | NU base/ 2006 Coal ($M) | diff | rev req for 46 MW of IGCC | ECC for 46 MW of NGCC | IGCC rev req vs NGCC ECC |
|---|---|---|---|---|---|---|
| 1990 | - | - | | | | |
| 1991 | 80.191 | 80.191 | 0.000 | - | - | - |
| 1992 | 91.595 | 91.595 | 0.000 | - | - | - |
| 1993 | 98.939 | 98.939 | 0.000 | - | - | - |
| 1994 | 101.433 | 101.433 | 0.000 | - | - | - |
| 1995 | 118.875 | 118.638 | -0.237 | - | - | - |
| 1996 | 145.677 | 145.766 | 0.089 | - | - | - |
| 1997 | 142.999 | 144.460 | 1.461 | - | - | - |
| 1998 | 167.743 | 165.068 | -2.675 | - | - | - |
| 1999 | 176.163 | 178.613 | 2.450 | - | - | - |
| 2000 | 170.919 | 175.467 | 4.548 | - | - | - |
| 2001 | 197.693 | 204.293 | 6.600 | - | - | - |
| 2002 | 209.269 | 222.572 | 13.303 | - | - | - |
| 2003 | 203.850 | 219.845 | 15.995 | - | - | - |
| 2004 | 235.719 | 246.774 | 11.055 | - | - | - |
| 2005 | 247.303 | 261.688 | 14.385 | - | - | - |
| 2006 | 239.014 | 276.761 | 37.747 | 55.47 | 35.20 | 20.27 |
| 2007 | 275.369 | 311.303 | 35.934 | 55.14 | 37.39 | 17.75 |
| 2008 | 291.305 | 325.455 | 34.150 | 54.66 | 39.69 | 14.97 |
| 2009 | 279.941 | 312.800 | 32.859 | 54.20 | 42.03 | 12.17 |
| 2010 | 323.543 | 354.779 | 31.236 | 53.97 | 44.55 | 9.43 |
| 2011 | 329.280 | 359.356 | 30.076 | 53.81 | 46.96 | 6.85 |
| 2012 | 553.398 | 581.121 | 27.723 | 53.68 | 49.38 | 4.30 |
| 2013 | 588.839 | 615.372 | 26.533 | 53.61 | 51.80 | 1.80 |
| 2014 | 616.516 | 641.523 | 25.007 | 53.77 | 54.38 | (0.61) |
| 2015 | 678.064 | 689.529 | 11.465 | 53.80 | 57.07 | (3.28) |
| | | | | **63.71** | **51.25** | **12.46** |

| Cumul. NPVRR $M | | | Diff btwn 46 MW C3 and no C3 Base | IGCC vs NGCC ECC diff | estimate of diff between HQ C3 plan and Base No C3 |
|---|---|---|---|---|---|
| 1991 | 72.062 | 72.062 | 0.000 | - | - |
| 1992 | 146.029 | 146.029 | 0.000 | - | - |
| 1993 | 217.828 | 217.828 | 0.000 | - | - |
| 1994 | 283.975 | 283.975 | 0.000 | - | - |
| 1995 | 353.638 | 353.500 | -0.139 | - | (0.139) |
| 1996 | 430.355 | 430.263 | -0.092 | - | (0.092) |
| 1997 | 498.028 | 498.627 | 0.599 | - | 0.599 |
| 1998 | 569.363 | 568.825 | -0.538 | - | (0.538) |
| 1999 | 636.686 | 637.084 | 0.398 | - | 0.398 |
| 2000 | 695.383 | 697.343 | 1.960 | - | 1.960 |
| 2001 | 756.394 | 760.390 | 3.997 | - | 3.997 |
| 2002 | 814.430 | 822.116 | 7.686 | - | 7.686 |
| 2003 | 865.233 | 876.905 | 11.672 | - | 11.672 |
| 2004 | 918.023 | 932.171 | 14.148 | - | 14.148 |
| 2005 | 967.794 | 984.837 | 17.043 | - | 17.043 |
| 2006 | 1011.020 | 1034.890 | 23.870 | 3.666 | 20.204 |
| 2007 | 1055.773 | 1085.483 | 29.710 | 6.551 | 23.159 |
| 2008 | 1098.317 | 1133.015 | 34.697 | 8.738 | 25.959 |
| 2009 | 1135.058 | 1174.068 | 39.010 | 10.336 | 28.674 |
| 2010 | 1173.216 | 1215.910 | 42.694 | 11.447 | 31.246 |
| 2011 | 1208.114 | 1253.996 | 45.881 | 12.173 | 33.708 |
| 2012 | 1260.821 | 1309.342 | 48.522 | 12.583 | 35.939 |
| 2013 | 1311.217 | 1362.010 | 50.793 | 12.737 | 38.055 |
| 2014 | 1358.634 | 1411.350 | 52.716 | 12.690 | 40.025 |
| 2015 | 1405.499 | 1459.007 | **53.508** | 12.464 | **41.044** |

## Comparison of post-DSM Rev req: Benchmark plan versus No HQ C3 Base: Low fuel

| | HQ C3 ($M) | No HQ C3 Base With low fuel ($M) | diff | rev req for 46 MW of IGCC | ECC for 46 MW of NGCC | IGCC rev req vs NGCC ECC | CY vs Norwalk |
|---|---|---|---|---|---|---|---|
| 1991 | 74,823 | 74,823 | - | - | - | - | - |
| 1992 | 86,921 | 86,921 | - | - | - | - | - |
| 1993 | 91,164 | 91,164 | - | - | - | - | - |
| 1994 | 91,169 | 91,169 | - | - | - | - | - |
| 1995 | 109,095 | 108,895 | (200) | - | - | - | - |
| 1996 | 135,129 | 135,198 | 69 | - | - | - | 650 |
| 1997 | 131,540 | 132,800 | 1,260 | - | - | - | 2,148 |
| 1998 | 146,392 | 147,027 | 635 | - | - | - | 2,362 |
| 1999 | 151,971 | 154,544 | 2,573 | - | - | - | 3,749 |
| 2000 | 144,766 | 149,800 | 5,034 | - | - | - | 4,143 |
| 2001 | 166,152 | 169,363 | 3,211 | - | - | - | 3,944 |
| 2002 | 171,890 | 176,556 | 4,666 | - | - | - | 2,784 |
| 2003 | 165,565 | 172,406 | 6,841 | - | - | - | 4,263 |
| 2004 | 184,939 | 191,084 | 6,145 | - | - | - | 5,043 |
| 2005 | 191,012 | 195,650 | 4,638 | - | - | - | 5,278 |
| 2006 | 191,695 | 240,463 | 48,768 | 54,000 | 26,695 | 27,305 | 3,028 |
| 2007 | 213,208 | 264,390 | 51,182 | 53,524 | 28,038 | 25,486 | - |
| 2008 | 242,315 | 287,790 | 45,475 | 52,888 | 29,452 | 23,436 | - |
| 2009 | 231,916 | 275,143 | 43,227 | 52,280 | 30,943 | 21,338 | - |
| 2010 | 253,481 | 300,070 | 46,589 | 51,888 | 32,513 | 19,375 | - |
| 2011 | 256,675 | 300,298 | 43,623 | 51,526 | 34,168 | 17,359 | - |
| 2012 | 393,487 | 439,829 | 46,342 | 51,196 | 35,912 | 15,284 | - |
| 2013 | 399,642 | 444,276 | 44,634 | 50,899 | 37,750 | 13,148 | - |
| 2014 | 401,826 | 447,308 | 45,482 | 50,822 | 39,689 | 11,133 | - |
| 2015 | 410,770 | 455,958 | 45,188 | 50,594 | 41,733 | 8,862 | - |

| Cumul. NPVRR $M | | | Diff btwn benchmark and no C3 Base | IGCC/NGCC diff | Revised estimate of diff between HQ C3 plan and Base No C3 | NU Base CY vs Norwalk | Revised estimate of diff between HQ C3 plan and Base No C3 |
|---|---|---|---|---|---|---|---|
| 1991 | 67,238 | 67,238 | - | - | - | - | - |
| 1992 | 137,431 | 137,431 | - | - | - | - | - |
| 1993 | 203,587 | 203,587 | - | - | - | - | - |
| 1994 | 263,041 | 263,041 | - | - | - | - | - |
| 1995 | 326,973 | 326,856 | (117) | - | (117) | - | (117) |
| 1996 | 398,135 | 398,054 | (81) | - | (81) | - | (81) |
| 1997 | 460,385 | 460,900 | 515 | - | 515 | 381 | 135 |
| 1998 | 522,641 | 523,426 | 785 | - | 785 | 1,512 | (726) |
| 1999 | 580,718 | 582,487 | 1,769 | - | 1,769 | 2,630 | (861) |
| 2000 | 630,434 | 633,931 | 3,498 | - | 3,498 | 4,224 | (727) |
| 2001 | 681,710 | 686,199 | 4,488 | - | 4,488 | 5,808 | (1,319) |
| 2002 | 729,380 | 735,163 | 5,783 | - | 5,783 | 7,162 | (1,380) |
| 2003 | 770,642 | 778,129 | 7,487 | - | 7,487 | 8,021 | (534) |
| 2004 | 812,060 | 820,923 | 8,864 | - | 8,864 | 9,203 | (340) |
| 2005 | 850,502 | 860,299 | 9,797 | - | 9,797 | 10,460 | (663) |
| 2006 | 885,170 | 903,787 | 18,617 | 4,938 | 13,679 | 11,642 | 2,036 |
| 2007 | 919,821 | 946,756 | 26,935 | 9,080 | 17,855 | 12,252 | 5,603 |
| 2008 | 955,210 | 988,787 | 33,576 | 12,503 | 21,074 | 12,252 | 8,822 |
| 2009 | 985,647 | 1,024,897 | 39,250 | 15,303 | 23,946 | 12,252 | 11,695 |
| 2010 | 1,015,543 | 1,060,287 | 44,744 | 17,588 | 27,156 | 12,252 | 14,904 |
| 2011 | 1,042,746 | 1,092,114 | 49,368 | 19,428 | 29,940 | 12,252 | 17,688 |
| 2012 | 1,080,222 | 1,134,004 | 53,781 | 20,884 | 32,898 | 12,252 | 20,646 |
| 2013 | 1,114,426 | 1,172,028 | 57,601 | 22,009 | 35,592 | 12,252 | 23,341 |
| 2014 | 1,145,331 | 1,206,431 | 61,100 | 22,865 | 38,234 | 12,252 | 25,983 |
| 2015 | 1,173,722 | 1,237,944 | **64,223** | 23,478 | **40,745** | 12,252 | **28,493** |

**Comparison of post-DSM rev req: Benchmark vs No HQ C3 Base: Base fuel**

| | HQ C3 ($M) | system Base w/o C3 ($M) | diff | rev req for 46 MW of IGCC | ECC for 46 MW of NGCC | IGCC rev req vs NGCC ECC |
|---|---|---|---|---|---|---|
| 1991 | 75,773 | 75,773 | - | - | - | - |
| 1992 | 88,391 | 88,391 | - | - | - | - |
| 1993 | 92,944 | 92,944 | - | - | - | - |
| 1994 | 93,399 | 93,399 | - | - | - | - |
| 1995 | 112,075 | 111,965 | (110) | - | - | - |
| 1996 | 138,449 | 139,088 | 639 | - | - | - |
| 1997 | 135,160 | 137,160 | 2,000 | - | - | - |
| 1998 | 152,912 | 153,847 | 935 | - | - | - |
| 1999 | 160,001 | 163,754 | 3,753 | - | - | - |
| 2000 | 153,306 | 160,040 | 6,734 | - | - | - |
| 2001 | 176,362 | 180,233 | 3,871 | - | - | - |
| 2002 | 184,000 | 190,266 | 6,266 | - | - | - |
| 2003 | 177,435 | 186,516 | 9,081 | - | - | - |
| 2004 | 201,629 | 208,774 | 7,145 | - | - | - |
| 2005 | 210,522 | 217,490 | 6,968 | - | - | - |
| 2006 | 208,225 | 240,203 | 31,978 | 55,472 | 35,201 | 20,270 |
| 2007 | 236,658 | 267,040 | 30,382 | 55,140 | 37,386 | 17,754 |
| 2008 | 260,945 | 289,920 | 28,975 | 54,661 | 39,686 | 14,975 |
| 2009 | 247,956 | 276,603 | 28,647 | 54,200 | 42,028 | 12,172 |
| 2010 | 277,761 | 304,820 | 27,059 | 53,972 | 44,546 | 9,425 |
| 2011 | 277,275 | 304,078 | 26,803 | 53,808 | 46,959 | 6,849 |
| 2012 | 424,337 | 450,539 | 26,202 | 53,678 | 49,378 | 4,300 |
| 2013 | 433,242 | 458,596 | 25,354 | 53,607 | 51,802 | 1,805 |
| 2014 | 438,646 | 463,328 | 24,682 | 53,771 | 54,379 | (608) |
| 2015 | 465,070 | 478,538 | 13,468 | 53,797 | 57,073 | (3,276) |

| Cumul. NPVRR $M | | | Diff btwn benchmark and no C3 Base | IGCC/NGCC diff | Revised diff between HQ C3 plan and Base No C3 |
|---|---|---|---|---|---|
| 1991 | 68,092 | 68,092 | - | - | - |
| 1992 | 139,472 | 139,472 | - | - | - |
| 1993 | 206,920 | 206,920 | - | - | - |
| 1994 | 267,828 | 267,828 | - | - | - |
| 1995 | 333,506 | 333,442 | (64) | - | (64) |
| 1996 | 406,416 | 406,688 | 272 | - | 272 |
| 1997 | 470,379 | 471,598 | 1,219 | - | 1,219 |
| 1998 | 535,408 | 537,024 | 1,616 | - | 1,616 |
| 1999 | 596,554 | 599,604 | 3,050 | - | 3,050 |
| 2000 | 649,203 | 654,566 | 5,363 | - | 5,363 |
| 2001 | 703,630 | 710,188 | 6,558 | - | 6,558 |
| 2002 | 754,658 | 762,954 | 8,295 | - | 8,295 |
| 2003 | 798,878 | 809,437 | 10,559 | - | 10,559 |
| 2004 | 844,034 | 856,193 | 12,159 | - | 12,159 |
| 2005 | 886,402 | 899,963 | 13,561 | - | 13,561 |
| 2006 | 924,060 | 943,405 | 19,344 | 3,666 | 15,678 |
| 2007 | 962,522 | 986,804 | 24,282 | 6,551 | 17,731 |
| 2008 | 1,000,632 | 1,029,146 | 28,514 | 8,738 | 19,775 |
| 2009 | 1,033,175 | 1,065,448 | 32,273 | 10,336 | 21,938 |
| 2010 | 1,065,934 | 1,101,398 | 35,465 | 11,447 | 24,017 |
| 2011 | 1,095,320 | 1,133,626 | 38,305 | 12,173 | 26,132 |
| 2012 | 1,135,735 | 1,176,536 | 40,801 | 12,583 | 28,218 |
| 2013 | 1,172,814 | 1,215,785 | 42,971 | 12,737 | 30,234 |
| 2014 | 1,206,551 | 1,251,420 | 44,869 | 12,690 | 32,179 |
| 2015 | 1,238,694 | 1,284,495 | **45,800** | 12,464 | **33,336** |

## Comparison of Connecticut Yankee with Norwalk 2: low fuel case

| | ConnYke TOTAL | ConnYke fixed costs | | ConnYke variable costs | | | ConnYke capacity factor | | Norwalk 2 TOTAL | Norwalk 2 fixed costs | | Norwalk 2 variable cost | | Difference in Rev Req | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | cost/MWh | year starting 11/1 | year starting 1/1 | $/MWh | annualized change | WEFA 1991 esc | adj | UPLAN | cost/MWh | year starting 11/1 | year starting 1/1 | | #6 oil low esc | CY | N2 | diff | 85% of diff |
| 1994 | | 323 | | | | 1.6% | | | | 91 | | | | | | | |
| 1995 | 62.33 | 331 | 55 | 8.35 | | 6.2% | 62% | 10.37% | 51.83 | 112 | 19 | 33.57 | | 2.93 | 2.17 | 0.76 | 0.65 |
| 1996 | *63.45* | 372 | 338 | *8.35* | | 4.3% | | | *54.49* | 143 | 117 | 35.38 | 5.40% | 17.90 | 15.37 | 2.53 | 2.15 |
| 1997 | 69.68 | 396 | 376 | 8.36 | 0.06% | 4.3% | 59% | 50.25% | 59.82 | 114 | 138 | 37.29 | 5.40% | 19.65 | 16.87 | 2.78 | 2.36 |
| 1998 | 73.48 | 417 | 400 | 8.33 | -0.36% | 4.3% | 77% | 65.10% | 57.84 | 112 | 114 | 39.31 | 5.40% | 20.73 | 16.32 | 4.41 | 3.75 |
| 1999 | *77.14* | 438 | 421 | *8.56* | | 4.3% | | | *59.86* | 118 | 113 | 41.43 | 5.40% | 21.76 | 16.88 | 4.87 | 4.14 |
| 2000 | 80.85 | 461 | 442 | 8.80 | 2.78% | 4.4% | 64% | 54.20% | 64.40 | 173 | 127 | 43.67 | 5.40% | 22.81 | 18.17 | 4.64 | 3.94 |
| 2001 | 85.00 | 484 | 465 | 9.20 | 4.55% | 4.4% | 77% | 65.46% | 73.39 | 142 | 168 | 46.02 | 5.40% | 23.98 | 20.70 | 3.28 | 2.78 |
| 2002 | *89.20* | 509 | 488 | *9.59* | | 4.0% | | | *71.42* | 133 | 141 | 48.51 | 5.40% | 25.16 | 20.15 | 5.02 | 4.26 |
| 2003 | 93.71 | 535 | 513 | 10.00 | 4.26% | 4.0% | 64% | 54.47% | 72.68 | 128 | 132 | 51.13 | 5.40% | 26.43 | 20.50 | 5.93 | 5.04 |
| 2004 | 98.41 | 563 | 540 | 10.40 | 4.00% | 4.0% | 77% | 65.72% | 76.39 | 188 | 138 | 53.89 | 5.40% | 27.76 | 21.55 | 6.21 | 5.28 |
| 2005 | 102.61 | | 469 | 10.80 | 3.85% | 4.0% | 72% | 55.03% | 87.46 | | 157 | 56.80 | 5.40% | 24.12 | 20.56 | 3.56 | 3.03 |
| | $472.95 | | | | | | | | $386.82 | | | | | | | | $12.25 |
| | | | | | | | 70% | | | | | | | | | | |

Assumptions:

| | |
|---|---|
| number of winter months | 6 |
| ConnYke winter % | 100% |
| ConnYke summer % | 70% |
| ConnYke cap facotr | 70% |
| Norwalk cap factor | 70% |
| capacity | 46 |

Derivation of 1995 Norwalk fuel cost/MWh
from base case 1997 cost of: 44.84

| | *base case escalation* | *base case cost/MWh* | *low case escalation* | *low case cost/MWh* |
|---|---|---|---|---|
| 1991 | | 27.92 | | 27.92 |
| 1992 | 4.1% | 29.07 | -0.9% | 27.67 |
| 1993 | 8.7% | 31.60 | 9.2% | 30.22 |
| 1994 | 7.6% | 34.00 | 5.4% | 31.85 |
| 1995 | 9.1% | 37.09 | 5.4% | 33.57 |
| 1996 | 9.7% | 40.69 | 5.4% | 35.38 |
| 1997 | 10.2% | 44.84 | 5.4% | 37.29 |

NU contract starting date 11/1/95; ending date 10/31/05

## Comparison of the Costs of Purchasing Power from Connecticut Yankee versus Norwalk 2

| | ConnYke | | | | | | | | Norwalk 2 | | | | | | Difference in Rev Req | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | TOTAL | fixed costs | | variable costs | | | capacity factor | | TOTAL | fixed costs | | variable costs | | | | | | |
| | cost/MWh | year starting 11/1 | year starting 1/1 [1] | $/MWh | annualized change | WEFA 1991 esc | adj. | UPLAN | cost/MWh | year starting 11/1 | year starting 1/1 | $/MWh | annualized change | WEFA 1991 #6 oil | CY | N2 | diff | 85% of diff |
| 1994 | | 323 | | | | 1.6% | | | | 91 | | | | | | | | |
| 1995 | 62.33 | 331 | 55 | 8.35 | | 6.2% | | 10.37% | 55.36 | 112 | 19 | *37.09* | | 9.10% | 2.93 | 2.60 | 0.33 | 0.28 |
| 1996 | *63.45* | 372 | 338 | *8.35* | | 4.3% | | | 59.80 | 143 | 117 | *40.69* | | 9.70% | 17.90 | 16.87 | 1.03 | 0.88 |
| 1997 | 69.68 | 396 | 376 | 8.36 | 0.06% | 4.3% | 59% | 50.25% | 67.37 | 114 | 138 | 44.84 | | 10.20% | 19.65 | 19.00 | 0.65 | 0.55 |
| 1998 | 73.48 | 417 | 400 | 8.33 | -0.36% | 4.3% | 77% | 65.10% | 67.75 | 112 | 114 | 49.21 | 9.75% | 9.80% | 20.73 | 19.11 | 1.62 | 1.37 |
| 1999 | *77.14* | 438 | 421 | *8.56* | | 4.3% | | | 72.20 | 118 | 113 | *53.77* | | 9.30% | 21.76 | 20.36 | 1.39 | 1.18 |
| 2000 | 80.85 | 461 | 442 | 8.80 | 2.78% | 4.4% | 64% | 54.20% | 79.49 | 173 | 127 | 58.75 | 9.26% | 9.20% | 22.81 | 22.42 | 0.39 | 0.33 |
| 2001 | 85.00 | 484 | 465 | 9.20 | 4.55% | 4.4% | 77% | 65.46% | 91.05 | 142 | 168 | 63.68 | 8.39% | 8.40% | 23.98 | 25.68 | -1.71 | -1.45 |
| 2002 | *89.20* | 509 | 488 | *9.59* | | 4.0% | | | 91.55 | 133 | 141 | *68.64* | | 8.20% | 25.16 | 25.82 | -0.66 | -0.56 |
| 2003 | 93.71 | 535 | 513 | 10.00 | 4.26% | 4.0% | 64% | 54.47% | 95.54 | 128 | 132 | 73.99 | 7.79% | 7.40% | 26.43 | 26.95 | -0.52 | -0.44 |
| 2004 | 98.41 | 563 | 540 | 10.40 | 4.00% | 4.0% | 77% | 65.72% | 101.81 | 188 | 138 | 79.31 | 7.19% | 7.20% | 27.76 | 28.72 | -0.96 | -0.82 |
| 2005 | 102.61 | | 469 | 10.80 | 3.85% | 4.0% | 72% | 55.03% | 115.64 | | 157 | 84.98 | 7.15% | 7.20% | 24.12 | 27.18 | -3.06 | -2.60 |
| NPV | $472.95 | | | | | | | | $464.46 | | | | | | | | | **$0.94** |
| | | | | | | | 70% | | | | | | | | | | | |

Assumptions:

| | | |
|---|---|---|
| number of winter months | 6 | |
| ConnYke winter % | 100% | |
| ConnYke summer % | 70% | |
| ConnYke cap facotr | 70% | |
| Norwalk cap factor | 70% | |
| capacity | 46 | MW |

Notes:

## Comparison of HQ C3 and Norwalk 2: low fuel case

| | Norwalk 2 | | | | | HQ C3 | | | | | | Difference in Rev Req | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | TOTAL | ixed costs/kW-yr [1 | | variable costs | | TOTAL | fixed costs/kW-yr | | variable costs/MWh | | | | | |
| | cost/MWh | year starting 11/1 | year starting 1/1 | $/MWh [2] | #6 oil low esc [3] | | year starting 11/1 [3] | year starting 1/1 [3] | year starting 11/1 [3] | year starting 1/1 | GNPIPD [3] | N2 | HQ C3 | diff |
| 1994 | | 91 | | | | | | | | | | | | |
| 1995 | 50.62 | 112 | 19 | 33.57 | | 68.87 | 277.83 | 46.31 | 26.58 | 26.58 | | | | |
| 1996 | 53.22 | 143 | 117 | 35.38 | 5.40% | 69.06 | 277.83 | 277.83 | 27.71 | 26.77 | 4.25% | 16.08 | 20.87 | 4.79 |
| 1997 | 58.32 | 114 | 138 | 37.29 | 5.40% | 70.20 | 277.83 | 277.83 | 28.90 | 27.91 | 4.31% | 17.63 | 21.21 | 3.59 |
| 1998 | 56.61 | 112 | 114 | 39.31 | 5.40% | 71.40 | 277.83 | 277.83 | 30.16 | 29.11 | 4.33% | 17.11 | 21.58 | 4.47 |
| 1999 | 58.63 | 118 | 113 | 41.43 | 5.40% | 72.66 | 277.83 | 277.83 | 31.47 | 30.37 | 4.35% | 17.72 | 21.96 | 4.24 |
| 2000 | 63.02 | 173 | 127 | 43.67 | 5.40% | 73.99 | 277.83 | 277.83 | 32.85 | 31.70 | 4.39% | 19.05 | 22.36 | 3.31 |
| 2001 | 71.57 | 142 | 168 | 46.02 | 5.40% | 75.35 | 277.83 | 277.83 | 34.15 | 33.06 | 3.95% | 21.63 | 22.77 | 1.14 |
| 2002 | 69.89 | 133 | 141 | 48.51 | 5.40% | 76.66 | 277.83 | 277.83 | 35.49 | 34.37 | 3.95% | 21.12 | 23.17 | 2.04 |
| 2003 | 71.25 | 128 | 132 | 51.13 | 5.40% | 78.02 | 277.83 | 277.83 | 36.90 | 35.73 | 3.95% | 21.53 | 23.58 | 2.05 |
| 2004 | 74.89 | 188 | 138 | 53.89 | 5.40% | 79.43 | 277.83 | 277.83 | 38.35 | 37.14 | 3.95% | 22.63 | 24.00 | 1.37 |
| 2005 | 85.41 | | 188 | 56.80 | 5.40% | 80.89 | 277.83 | 277.83 | 39.87 | 38.61 | 3.95% | 25.81 | 24.45 | -1.37 |
| NPV to 1994 | $370.18 | | | | | $428.57 | | | | | | | | $17.65 |
| NPV to 1990 | | | | | | | | | | | | | | $10.34 |

Assumptions:
HQ C3 and NU contract starting date 11/1/95
NU contract will be available for the last 2 months of 2005 at the same price/kW-mo
HQ capacity factor 75%

## Comparison of Connecticut Yankee with Norwalk 2: low fuel case

| | ConnYke TOTAL | ConnYke fixed costs | | ConnYke variable costs | | | ConnYke capacity factor | | Norwalk 2 TOTAL | Norwalk 2 fixed costs | | Norwalk 2 variable cost | | Difference in Rev Req | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | cost/MWh | year starting 11/1 | year starting 1/1 | $/MWh | annualized change | WEFA 1991 esc | adj | UPLAN | cost/MWh | year starting 11/1 | year starting 1/1 | | #6 oil low esc | CY | N2 | diff | 85% of diff |
| 1994 | | 323 | | | | 1.6% | | | | 91 | | | | | | | |
| 1995 | 62.33 | 331 | 55 | 8.35 | | 6.2% | 62% | 10.37% | 51.83 | 112 | 19 | 33.57 | | 2.93 | 2.17 | 0.76 | 0.65 |
| 1996 | *63.45* | 372 | 338 | *8.35* | | 4.3% | | | *54.49* | 143 | 117 | 35.38 | 5.40% | 17.90 | 15.37 | 2.53 | 2.15 |
| 1997 | 69.68 | 396 | 376 | 8.36 | 0.06% | 4.3% | 59% | 50.25% | 59.82 | 114 | 138 | 37.29 | 5.40% | 19.65 | 16.87 | 2.78 | 2.36 |
| 1998 | 73.48 | 417 | 400 | 8.33 | -0.36% | 4.3% | 77% | 65.10% | 57.84 | 112 | 114 | 39.31 | 5.40% | 20.73 | 16.32 | 4.41 | 3.75 |
| 1999 | *77.14* | 438 | 421 | *8.56* | | 4.3% | | | *59.86* | 118 | 113 | 41.43 | 5.40% | 21.76 | 16.88 | 4.87 | 4.14 |
| 2000 | 80.85 | 461 | 442 | 8.80 | 2.78% | 4.4% | 64% | 54.20% | 64.40 | 173 | 127 | 43.67 | 5.40% | 22.81 | 18.17 | 4.64 | 3.94 |
| 2001 | 85.00 | 484 | 465 | 9.20 | 4.55% | 4.4% | 77% | 65.46% | 73.39 | 142 | 168 | 46.02 | 5.40% | 23.98 | 20.70 | 3.28 | 2.78 |
| 2002 | *89.20* | 509 | 488 | *9.59* | | 4.0% | | | *71.42* | 133 | 141 | 48.51 | 5.40% | 25.16 | 20.15 | 5.02 | 4.26 |
| 2003 | 93.71 | 535 | 513 | 10.00 | 4.26% | 4.0% | 64% | 54.47% | 72.68 | 128 | 132 | 51.13 | 5.40% | 26.43 | 20.50 | 5.93 | 5.04 |
| 2004 | 98.41 | 563 | 540 | 10.40 | 4.00% | 4.0% | 77% | 65.72% | 76.39 | 188 | 138 | 53.89 | 5.40% | 27.76 | 21.55 | 6.21 | 5.28 |
| 2005 | 102.61 | | 469 | 10.80 | 3.85% | 4.0% | 72% | 55.03% | 87.46 | | 157 | 56.80 | 5.40% | 24.12 | 20.56 | 3.56 | 3.03 |
| | $472.95 | | | | | | | | $386.82 | | | | | | | | $12.25 |
| | | | | | | | 70% | | | | | | | | | | |

Assumptions:

| | |
|---|---|
| number of winter months | 6 |
| ConnYke winter % | 100% |
| ConnYke summer % | 70% |
| ConnYke cap facotr | 70% |
| Norwalk cap factor | 70% |
| capacity | 46 |
| Derivation of 1995 Norwalk fuel cost/MWh from base case 1997 cost of: | 44.84 |

| | *base case escalation* | *base case cost/MWh* | *low case escalation* | *low case cost/MWh* |
|---|---|---|---|---|
| 1991 | | 27.92 | | 27.92 |
| 1992 | 4.1% | 29.07 | -0.9% | 27.67 |
| 1993 | 8.7% | 31.60 | 9.2% | 30.22 |
| 1994 | 7.6% | 34.00 | 5.4% | 31.85 |
| 1995 | 9.1% | 37.09 | 5.4% | 33.57 |
| 1996 | 9.7% | 40.69 | 5.4% | 35.38 |
| 1997 | 10.2% | 44.84 | 5.4% | 37.29 |

NU contract starting date 11/1/95; ending date 10/31/05

## Comparison of the Costs of Purchasing Power from Connecticut Yankee versus Norwalk 2

| | ConnYke | | | | | | | | Norwalk 2 | | | | | | Difference in Rev Req | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | TOTAL | fixed costs | | variable costs | | | capacity factor | | TOTAL | fixed costs | | variable costs | | | | | | |
| | cost/MWh | year starting 11/1 | year starting 1/1 [1] | $/MWh | annualized change | WEFA 1991 esc | adj. | UPLAN | cost/MWh | year starting 11/1 | year starting 1/1 | $/MWh | annualized change | WEFA 1991 #6 oil | CY | N2 | diff | 85% of diff |
| 1994 | | 323 | | | | 1.6% | | | | 91 | | | | | | | | |
| 1995 | 62.33 | 331 | 55 | 8.35 | | 6.2% | | 10.37% | 55.36 | 112 | 19 | *37.09* | | 9.10% | 2.93 | 2.60 | 0.33 | 0.28 |
| 1996 | *63.45* | 372 | 338 | *8.35* | | 4.3% | | | 59.80 | 143 | 117 | *40.69* | | 9.70% | 17.90 | 16.87 | 1.03 | 0.88 |
| 1997 | 69.68 | 396 | 376 | 8.36 | 0.06% | 4.3% | 59% | 50.25% | 67.37 | 114 | 138 | 44.84 | | 10.20% | 19.65 | 19.00 | 0.65 | 0.55 |
| 1998 | 73.48 | 417 | 400 | 8.33 | -0.36% | 4.3% | 77% | 65.10% | 67.75 | 112 | 114 | 49.21 | 9.75% | 9.80% | 20.73 | 19.11 | 1.62 | 1.37 |
| 1999 | *77.14* | 438 | 421 | *8.56* | | 4.3% | | | 72.20 | 118 | 113 | *53.77* | | 9.30% | 21.76 | 20.36 | 1.39 | 1.18 |
| 2000 | 80.85 | 461 | 442 | 8.80 | 2.78% | 4.4% | 64% | 54.20% | 79.49 | 173 | 127 | 58.75 | 9.26% | 9.20% | 22.81 | 22.42 | 0.39 | 0.33 |
| 2001 | 85.00 | 484 | 465 | 9.20 | 4.55% | 4.4% | 77% | 65.46% | 91.05 | 142 | 168 | 63.68 | 8.39% | 8.40% | 23.98 | 25.68 | -1.71 | -1.45 |
| 2002 | *89.20* | 509 | 488 | *9.59* | | 4.0% | | | 91.55 | 133 | 141 | *68.64* | | 8.20% | 25.16 | 25.82 | -0.66 | -0.56 |
| 2003 | 93.71 | 535 | 513 | 10.00 | 4.26% | 4.0% | 64% | 54.47% | 95.54 | 128 | 132 | 73.99 | 7.79% | 7.40% | 26.43 | 26.95 | -0.52 | -0.44 |
| 2004 | 98.41 | 563 | 540 | 10.40 | 4.00% | 4.0% | 77% | 65.72% | 101.81 | 188 | 138 | 79.31 | 7.19% | 7.20% | 27.76 | 28.72 | -0.96 | -0.82 |
| 2005 | 102.61 | | 469 | 10.80 | 3.85% | 4.0% | 72% | 55.03% | 115.64 | | 157 | 84.98 | 7.15% | 7.20% | 24.12 | 27.18 | -3.06 | -2.60 |
| NPV | $472.95 | | | | | | | | $464.46 | | | | | | | | | **$0.94** |
| | | | | | | | 70% | | | | | | | | | | | |

Assumptions:

| | | |
|---|---|---|
| number of winter months | 6 | |
| ConnYke winter % | 100% | |
| ConnYke summer % | 70% | |
| ConnYke cap facotr | 70% | |
| Norwalk cap factor | 70% | |
| capacity | 46 | MW |

Notes:

**Comparison of revenue requirements**

| | |
|---|---|
| Nominal discount rate | 11.28% |
| Inflation rate | 3.95% |
| Real discount rate | 7.05% |
| 2006 Gas CC capital cost ($/kW) | 1506 |
| 2006 Coal-Gasification capital cost ($/kW) | 4052 |
| Coal Capacity Factor | 75% |
| CC Capacity Factor | 75% |
| 1991 Gas Price/MMBtu | $2.35 |
| 1991 #2 oil price/Bbl | $25.97 |
| Heat content of #2 oil | 5.82 |
| Number of months of gas use | 7 |
| CC Heat Rate | 8214 |
| 1991 Coal Price | $48.55 |
| Heat content of coal | 25 |
| IGCC heat rate | 8855 |

| | | | | | | Combined-Cycle Costs | | | | | | | Coal-Gasification Combined-Cycle Costs | | | | | Total Cost for 46 MW | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | GNP Implicit Price Deflators | 30-Year Fixed Charge Factors | Coal Price Escalation | Gas Price Escalation | #2 Oil Price Escalation | CC Fixed Charge ($/kWyr) | CC Fixed O&M ($/kWyr) | CC Variable O&M ($/MWh) | CC Gas ($/MWh) | CC Oil ($/MWh) | CC Fuel ($/MWh) | Total Cost ($/MWh) | IGCC Fixed Charge ($/kWyr) | IGCC Fixed O&M ($/kWyr) | IGCC Variable O&M ($/MWh) | IGCC Fuel ($/MWh) | Total Cost ($/MWh) | CC (1000$) | IGCC (1000$) |
| 1990 | 4.56% | | | | | | 11.39 | | | | | | | 46.39 | | | | | |
| 1991 | 2.98% | | | | | | 11.73 | 2.06 | 19.30 | 36.65 | 26.53 | | | 47.77 | 3.63 | 17.20 | | | |
| 1992 | 2.98% | | 4.59% | 3.12% | -0.77% | | 12.08 | 2.12 | 19.91 | 36.37 | 26.77 | | | 49.20 | 3.74 | 17.99 | | | |
| 1993 | 3.28% | | 4.43% | 13.63% | 6.46% | | 12.48 | 2.19 | 22.62 | 38.72 | 29.33 | | | 50.81 | 3.86 | 18.78 | | | |
| 1994 | 3.48% | | 6.15% | 11.00% | 5.49% | | 12.91 | 2.27 | 25.11 | 40.85 | 31.66 | | | 52.58 | 4.00 | 19.94 | | | |
| 1995 | 3.95% | | 5.58% | 12.38% | 7.21% | | 13.42 | 2.36 | 28.21 | 43.79 | 34.70 | | | 54.65 | 4.15 | 21.05 | | | |
| 1996 | 4.15% | | 5.15% | 8.84% | 8.68% | | 13.98 | 2.45 | 30.71 | 47.59 | 37.74 | | | 56.92 | 4.33 | 22.13 | | | |
| 1997 | 4.25% | | 5.03% | 9.56% | 9.86% | | 14.57 | 2.56 | 33.64 | 52.28 | 41.41 | | | 59.34 | 4.51 | 23.25 | | | |
| 1998 | 4.21% | | 5.06% | 9.14% | 8.79% | | 15.18 | 2.67 | 36.72 | 56.88 | 45.12 | | | 61.84 | 4.70 | 24.42 | | | |
| 1999 | 4.33% | | 5.21% | 8.94% | 8.34% | | 15.84 | 2.78 | 40.00 | 61.62 | 49.01 | | | 64.52 | 4.90 | 25.70 | | | |
| 2000 | 4.35% | | 5.30% | 8.37% | 8.13% | | 16.53 | 2.90 | 43.35 | 66.63 | 53.05 | | | 67.32 | 5.12 | 27.06 | | | |
| 2001 | 4.39% | | 5.11% | 8.13% | 7.92% | | 17.26 | 3.03 | 46.87 | 71.91 | 57.31 | | | 70.28 | 5.34 | 28.44 | | | |
| 2002 | 3.95% | | 5.21% | 9.70% | 7.40% | | 17.94 | 3.15 | 51.42 | 77.23 | 62.18 | | | 73.06 | 5.55 | 29.92 | | | |
| 2003 | 3.95% | | 5.02% | 9.29% | 7.03% | | 18.65 | 3.27 | 56.20 | 82.66 | 67.22 | | | 75.94 | 5.77 | 31.42 | | | |
| 2004 | 3.95% | | 4.86% | 8.44% | 7.07% | | 19.38 | 3.40 | 60.94 | 88.51 | 72.43 | | | 78.94 | 6.00 | 32.95 | | | |
| 2005 | 3.95% | | 5.15% | 7.72% | 6.69% | | 20.15 | 3.54 | 65.65 | 94.43 | 77.64 | | | 82.06 | 6.24 | 34.65 | | | |
| 2006 | 3.95% | 0.207 | 5.10% | 7.59% | 6.24% | 311.74 | 20.94 | 3.68 | 70.63 | 100.32 | 83.00 | 137.32 | 838.76 | 85.30 | 6.48 | 36.42 | 183.55 | 41,499 | 55,472 |
| 2007 | 3.95% | 0.201 | 5.04% | 7.30% | 6.94% | 302.71 | 21.77 | 3.82 | 75.78 | 107.28 | 88.91 | 142.12 | 814.45 | 88.67 | 6.74 | 38.25 | 182.45 | 42,951 | 55,140 |
| 2008 | 3.95% | 0.194 | 5.05% | 7.42% | 6.61% | 292.16 | 22.63 | 3.97 | 81.41 | 114.37 | 95.14 | 147.03 | 786.09 | 92.17 | 7.00 | 40.18 | 180.86 | 44,436 | 54,661 |
| 2009 | 3.95% | 0.187 | 4.88% | 7.26% | 6.03% | 281.62 | 23.52 | 4.13 | 87.32 | 121.27 | 101.46 | 152.04 | 757.72 | 95.81 | 7.28 | 42.14 | 179.34 | 45,950 | 54,200 |
| 2010 | 3.95% | 0.181 | 4.94% | 7.32% | 6.17% | 272.59 | 24.45 | 4.29 | 93.71 | 128.75 | 108.31 | 157.82 | 733.41 | 99.60 | 7.57 | 44.23 | 178.58 | 47,695 | 53,972 |
| 2011 | 3.95% | 0.175 | 5.11% | 6.40% | 5.48% | 263.55 | 25.42 | 4.46 | 99.71 | 135.81 | 114.75 | 163.20 | 709.10 | 103.53 | 7.87 | 46.49 | 178.04 | 49,321 | 53,808 |
| 2012 | 3.95% | 0.169 | 5.03% | 5.84% | 5.31% | 254.51 | 26.42 | 4.64 | 105.53 | 143.02 | 121.15 | 168.55 | 684.79 | 107.62 | 8.18 | 48.82 | 177.61 | 50,940 | 53,678 |
| 2013 | 3.95% | 0.163 | 5.11% | 5.45% | 5.03% | 245.48 | 27.47 | 4.82 | 111.28 | 150.21 | 127.50 | 173.87 | 660.48 | 111.87 | 8.50 | 51.32 | 177.38 | 52,547 | 53,607 |
| 2014 | 3.95% | 0.158 | 5.10% | 5.41% | 5.24% | 237.95 | 28.55 | 5.01 | 117.30 | 158.08 | 134.29 | 179.87 | 640.22 | 116.29 | 8.84 | 53.94 | 177.92 | 54,361 | 53,771 |
| 2015 | 3.95% | 0.152 | 5.08% | 5.35% | 5.24% | 228.91 | 29.68 | 5.21 | 123.58 | 166.37 | 141.41 | 185.98 | 615.90 | 120.89 | 9.19 | 56.68 | 178.01 | 56,207 | 53,797 |
| 2016 | 3.95% | 0.146 | 5.06% | 5.88% | 5.03% | 219.88 | 30.85 | 5.42 | 130.84 | 174.74 | 149.13 | 192.71 | 591.59 | 125.66 | 9.55 | 59.54 | 178.26 | 58,242 | 53,875 |
| 2017 | 3.95% | 0.141 | 5.09% | 5.64% | 5.16% | 212.35 | 32.07 | 5.63 | 138.22 | 183.75 | 157.19 | 200.03 | 571.33 | 130.62 | 9.93 | 62.58 | 179.34 | 60,453 | 54,201 |
| 2018 | 3.95% | 0.135 | 5.06% | 5.60% | 5.04% | 203.31 | 33.34 | 5.86 | 145.96 | 193.01 | 165.57 | 207.44 | 547.02 | 135.78 | 10.32 | 65.74 | 179.99 | 62,693 | 54,396 |
| 2019 | 3.95% | 0.130 | 5.13% | 5.55% | 5.03% | 195.78 | 34.66 | 6.09 | 154.07 | 202.72 | 174.34 | 215.50 | 526.76 | 141.15 | 10.73 | 69.11 | 181.50 | 65,128 | 54,853 |
| 2020 | 3.95% | 0.124 | 5.08% | 5.33% | 5.24% | 186.74 | 36.02 | 6.33 | 162.28 | 213.34 | 183.55 | 223.79 | 502.45 | 146.72 | 11.15 | 72.63 | 182.58 | 67,633 | 55,180 |

| Year | GNP Implicit Price Deflator | 30-Year Fixed Charge Factors | Coal Price Escalation | Gas Price Escalation | #2 Oil Price Escalation | Combined-Cycle Costs: CC Fixed Charge ($/kWyr) | CC Fixed O&M ($/kWyr) | CC Variable O&M ($/MWh) | CC Gas ($/MWh) | CC Oil ($/MWh) | CC Fuel ($/MWh) | Total Cost ($/MWh) | Coal-Gasification Combined-Cycle Costs: IGCC Fixed Charge ($/kWyr) | IGCC Fixed O&M ($/kWyr) | IGCC Variable O&M ($/MWh) | IGCC Fuel ($/MWh) | Total Cost ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1990 | 4.56% | | | | | | 11.39 | | | | | | | 46.39 | | | |
| 1991 | 2.98% | | | | | | 11.73 | 2.06 | 19.30 | 36.65 | 26.53 | | | 47.77 | 3.63 | 17.20 | |
| 1992 | 2.98% | | 4.59% | 3.12% | -0.77% | | 12.08 | 2.12 | 19.91 | 36.37 | 26.77 | | | 49.20 | 3.74 | 17.99 | |
| 1993 | 3.28% | | 4.43% | 13.63% | 6.46% | | 12.48 | 2.19 | 22.62 | 38.72 | 29.33 | | | 50.81 | 3.86 | 18.78 | |
| 1994 | 3.48% | | 6.15% | 11.00% | 5.49% | | 12.91 | 2.27 | 25.11 | 40.85 | 31.66 | | | 52.58 | 4.00 | 19.94 | |
| 1995 | 3.95% | | 5.58% | 12.38% | 7.21% | | 13.42 | 2.36 | 28.21 | 43.79 | 34.70 | | | 54.65 | 4.15 | 21.05 | |
| 1996 | 4.15% | | 5.15% | 8.84% | 8.68% | | 13.98 | 2.45 | 30.71 | 47.59 | 37.74 | | | 56.92 | 4.33 | 22.13 | |
| 1997 | 4.25% | | 5.03% | 9.56% | 9.86% | | 14.57 | 2.56 | 33.64 | 52.28 | 41.41 | | | 59.34 | 4.51 | 23.25 | |
| 1998 | 4.21% | | 5.06% | 9.14% | 8.79% | | 15.18 | 2.67 | 36.72 | 56.88 | 45.12 | | | 61.84 | 4.70 | 24.42 | |
| 1999 | 4.33% | | 5.21% | 8.94% | 8.34% | | 15.84 | 2.78 | 40.00 | 61.62 | 49.01 | | | 64.52 | 4.90 | 25.70 | |
| 2000 | 4.35% | | 5.30% | 8.37% | 8.13% | | 16.53 | 2.90 | 43.35 | 66.63 | 53.05 | | | 67.32 | 5.12 | 27.06 | |
| 2001 | 4.39% | | 5.11% | 8.13% | 7.92% | | 17.26 | 3.03 | 46.87 | 71.91 | 57.31 | | | 70.28 | 5.34 | 28.44 | |
| 2002 | 3.95% | | 5.21% | 9.70% | 7.40% | | 17.94 | 3.15 | 51.42 | 77.23 | 62.18 | | | 73.06 | 5.55 | 29.92 | |
| 2003 | 3.95% | | 5.02% | 9.29% | 7.03% | | 18.65 | 3.27 | 56.20 | 82.66 | 67.22 | | | 75.94 | 5.77 | 31.42 | |
| 2004 | 3.95% | | 4.86% | 8.44% | 7.07% | | 19.38 | 3.40 | 60.94 | 88.51 | 72.43 | | | 78.94 | 6.00 | 32.95 | |
| 2005 | 3.95% | | 5.15% | 7.72% | 6.69% | | 20.15 | 3.54 | 65.65 | 94.43 | 77.64 | | | 82.06 | 6.24 | 34.65 | |
| 2006 | 3.95% | 0.207 | 5.10% | 7.59% | 6.24% | 311.74 | 20.94 | 3.68 | 70.63 | 100.32 | 83.00 | 137.32 | 838.76 | 85.30 | 6.48 | 36.42 | 183.55 |
| 2007 | 3.95% | 0.201 | 5.04% | 7.30% | 6.94% | 302.71 | 21.77 | 3.82 | 75.78 | 107.28 | 88.91 | 142.12 | 814.45 | 88.67 | 6.74 | 38.25 | 182.45 |
| 2008 | 3.95% | 0.194 | 5.05% | 7.42% | 6.61% | 292.16 | 22.63 | 3.97 | 81.41 | 114.37 | 95.14 | 147.03 | 786.09 | 92.17 | 7.00 | 40.18 | 180.86 |
| 2009 | 3.95% | 0.187 | 4.88% | 7.26% | 6.03% | 281.62 | 23.52 | 4.13 | 87.32 | 121.27 | 101.46 | 152.04 | 757.72 | 95.81 | 7.28 | 42.14 | 179.34 |
| 2010 | 3.95% | 0.181 | 4.94% | 7.32% | 6.17% | 272.59 | 24.45 | 4.29 | 93.71 | 128.75 | 108.31 | 157.82 | 733.41 | 99.60 | 7.57 | 44.23 | 178.58 |
| 2011 | 3.95% | 0.175 | 5.11% | 6.40% | 5.48% | 263.55 | 25.42 | 4.46 | 99.71 | 135.81 | 114.75 | 163.20 | 709.10 | 103.53 | 7.87 | 46.49 | 178.04 |
| 2012 | 3.95% | 0.169 | 5.03% | 5.84% | 5.31% | 254.51 | 26.42 | 4.64 | 105.53 | 143.02 | 121.15 | 168.55 | 684.79 | 107.62 | 8.18 | 48.82 | 177.61 |
| 2013 | 3.95% | 0.163 | 5.11% | 5.45% | 5.03% | 245.48 | 27.47 | 4.82 | 111.28 | 150.21 | 127.50 | 173.87 | 660.48 | 111.87 | 8.50 | 51.32 | 177.38 |
| 2014 | 3.95% | 0.158 | 5.10% | 5.41% | 5.24% | 237.95 | 28.55 | 5.01 | 117.30 | 158.08 | 134.29 | 179.87 | 640.22 | 116.29 | 8.84 | 53.94 | 177.92 |
| 2015 | 3.95% | 0.152 | 5.08% | 5.35% | 5.24% | 228.91 | 29.68 | 5.21 | 123.58 | 166.37 | 141.41 | 185.98 | 615.90 | 120.89 | 9.19 | 56.68 | 178.01 |
| 2016 | 3.95% | 0.146 | 5.06% | 5.88% | 5.03% | 219.88 | 30.85 | 5.42 | 130.84 | 174.74 | 149.13 | 192.71 | 591.59 | 125.66 | 9.55 | 59.54 | 178.26 |
| 2017 | 3.95% | 0.141 | 5.09% | 5.64% | 5.16% | 212.35 | 32.07 | 5.63 | 138.22 | 183.75 | 157.19 | 200.03 | 571.33 | 130.62 | 9.93 | 62.58 | 179.34 |
| 2018 | 3.95% | 0.135 | 5.06% | 5.60% | 5.04% | 203.31 | 33.34 | 5.86 | 145.96 | 193.01 | 165.57 | 207.44 | 547.02 | 135.78 | 10.32 | 65.74 | 179.99 |
| 2019 | 3.95% | 0.130 | 5.13% | 5.55% | 5.03% | 195.78 | 34.66 | 6.09 | 154.07 | 202.72 | 174.34 | 215.50 | 526.76 | 141.15 | 10.73 | 69.11 | 181.50 |
| 2020 | 3.95% | 0.124 | 5.08% | 5.33% | 5.24% | 186.74 | 36.02 | 6.33 | 162.28 | 213.34 | 183.55 | 223.79 | 502.45 | 146.72 | 11.15 | 72.63 | 182.58 |
| 2021 | 3.95% | 0.119 | *5.08%* | *5.33%* | *5.24%* | 179.21 | 37.45 | 6.58 | 170.93 | 224.52 | 193.26 | 232.81 | 482.19 | 152.52 | 11.59 | 76.31 | 184.51 |
| 2022 | 3.95% | 0.113 | *5.08%* | *5.33%* | *5.24%* | 170.18 | 38.93 | 6.84 | 180.04 | 236.29 | 203.47 | 242.14 | 457.88 | 158.54 | 12.05 | 80.19 | 186.06 |
| 2023 | 3.95% | 0.108 | *5.08%* | *5.33%* | *5.24%* | 162.65 | 40.46 | 7.11 | 189.63 | 248.67 | 214.23 | 252.25 | 437.62 | 164.81 | 12.52 | 84.26 | 188.48 |
| 2024 | 3.95% | 0.102 | *5.08%* | *5.33%* | *5.24%* | 153.61 | 42.06 | 7.39 | 199.74 | 261.70 | 225.56 | 262.73 | 413.30 | 171.32 | 13.02 | 88.55 | 190.55 |
| 2025 | 3.95% | 0.097 | *5.08%* | *5.33%* | *5.24%* | 146.08 | 43.72 | 7.68 | 210.39 | 275.41 | 237.48 | 274.05 | 393.04 | 178.08 | 13.53 | 93.04 | 193.50 |
| 2026 | 3.95% | 0.092 | *5.08%* | *5.33%* | *5.24%* | 138.55 | 45.45 | 7.98 | 221.60 | 289.84 | 250.04 | 286.02 | 372.78 | 185.12 | 14.07 | 97.77 | 196.75 |
| 2027 | 3.95% | 0.088 | *5.08%* | *5.33%* | *5.24%* | 132.53 | 47.25 | 8.30 | 233.41 | 305.03 | 263.25 | 298.91 | 356.58 | 192.43 | 14.62 | 102.74 | 200.92 |
| 2028 | 3.95% | 0.085 | *5.08%* | *5.33%* | *5.24%* | 128.01 | 49.11 | 8.63 | 245.85 | 321.02 | 277.17 | 312.76 | 344.42 | 200.03 | 15.20 | 107.96 | 206.02 |
| 2029 | 3.95% | 0.082 | *5.08%* | *5.33%* | *5.24%* | 123.49 | 51.05 | 8.97 | 258.96 | 337.84 | 291.82 | 327.36 | 332.26 | 207.93 | 15.80 | 113.44 | 211.46 |
| 2030 | 3.95% | 0.079 | *5.08%* | *5.33%* | *5.24%* | 118.97 | 53.07 | 9.32 | 272.76 | 355.54 | 307.25 | 342.76 | 320.11 | 216.14 | 16.42 | 119.20 | 217.25 |
| 2031 | 3.95% | 0.076 | *5.08%* | *5.33%* | *5.24%* | 114.46 | 55.17 | 9.69 | 287.30 | 374.17 | 323.49 | 359.00 | 307.95 | 224.68 | 17.07 | 125.26 | 223.40 |
| 2032 | 3.95% | 0.073 | *5.08%* | *5.33%* | *5.24%* | 109.94 | 57.34 | 10.07 | 302.61 | 393.78 | 340.60 | 376.13 | 295.80 | 233.56 | 17.75 | 131.62 | 229.94 |
| 2033 | 3.95% | 0.070 | *5.08%* | *5.33%* | *5.24%* | 105.42 | 59.61 | 10.47 | 318.74 | 414.41 | 358.60 | 394.19 | 283.64 | 242.78 | 18.45 | 138.31 | 236.88 |
| 2034 | 3.95% | 0.067 | *5.08%* | *5.33%* | *5.24%* | 100.90 | 61.96 | 10.88 | 335.73 | 436.13 | 377.56 | 413.23 | 271.48 | 252.37 | 19.18 | 145.33 | 244.25 |
| 2035 | 3.95% | 0.064 | *5.08%* | *5.33%* | *5.24%* | 96.38 | 64.41 | 11.31 | 353.62 | 458.98 | 397.52 | 433.31 | 259.33 | 262.34 | 19.93 | 152.72 | 252.05 |
| | | | | | | $2,076.20 | | | | | | $1,587 | | | | | $1,562 |

**Comparison of revenue requirements of IGCC and CGCC: low fuel case**

| | | | | | | Combined-Cycle Costs | | | | | | | Coal-Gasification Combined-Cycle Costs | | | | | Total Cost for 46 MW | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | GNP Implicit Price Deflators | Year Fixed Charge Factors | Coal Price Escalation | Gas Price Escalation | #2 Oil Price Escalation | CC Fixed Charge ($/kWyr) | CC Fixed O&M ($/kWyr) | CC Variable O&M ($/MWh) | CC Gas ($/MWh) | CC Oil ($/MWh) | CC Fuel ($/MWh) | Total Cost ($/MWh) | IGCC Fixed Charge ($/kWyr) | IGCC Fixed O&M ($/kWyr) | IGCC Variable O&M ($/MWh) | IGCC Fuel ($/MWh) | Total Cost ($/MWh) | CC (1000$) | IGCC (1000$) |
| 1990 | 4.56% | | | | | | 11.39 | | | | | | | 46.39 | | | | | |
| 1991 | 2.98% | | | | | | 11.73 | 2.06 | 19.14 | 36.20 | 26.25 | | | 47.77 | 3.63 | 16.86 | | | |
| 1992 | 2.98% | | 4.10% | 1.20% | -6.30% | | 12.08 | 2.12 | 19.37 | 33.92 | 25.43 | | | 49.20 | 3.74 | 17.55 | | | |
| 1993 | 3.28% | | 4.00% | 6.80% | 5.70% | | 12.48 | 2.19 | 20.69 | 35.85 | 27.01 | | | 50.81 | 3.86 | 18.25 | | | |
| 1994 | 3.48% | | 4.30% | 6.80% | 4.50% | | 12.91 | 2.27 | 22.09 | 37.47 | 28.50 | | | 52.58 | 4.00 | 19.03 | | | |
| 1995 | 3.95% | | 4.30% | 6.80% | 4.50% | | 13.42 | 2.36 | 23.59 | 39.15 | 30.08 | | | 54.65 | 4.15 | 19.85 | | | |
| 1996 | 4.15% | | 4.30% | 6.80% | 4.50% | | 13.98 | 2.45 | 25.20 | 40.91 | 31.75 | | | 56.92 | 4.33 | 20.71 | | | |
| 1997 | 4.25% | | 4.30% | 6.80% | 4.50% | | 14.57 | 2.56 | 26.91 | 42.76 | 33.51 | | | 59.34 | 4.51 | 21.60 | | | |
| 1998 | 4.21% | | 4.30% | 6.80% | 4.50% | | 15.18 | 2.67 | 28.74 | 44.68 | 35.38 | | | 61.84 | 4.70 | 22.53 | | | |
| 1999 | 4.33% | | 4.30% | 6.80% | 4.50% | | 15.84 | 2.78 | 30.70 | 46.69 | 37.36 | | | 64.52 | 4.90 | 23.49 | | | |
| 2000 | 4.35% | | 4.30% | 6.80% | 4.50% | | 16.53 | 2.90 | 32.78 | 48.79 | 39.45 | | | 67.32 | 5.12 | 24.50 | | | |
| 2001 | 4.39% | | 4.30% | 6.80% | 4.50% | | 17.26 | 3.03 | 35.01 | 50.99 | 41.67 | | | 70.28 | 5.34 | 25.56 | | | |
| 2002 | 3.95% | | 4.30% | 6.80% | 4.50% | | 17.94 | 3.15 | 37.39 | 53.28 | 44.01 | | | 73.06 | 5.55 | 26.66 | | | |
| 2003 | 3.95% | | 4.30% | 6.80% | 4.50% | | 18.65 | 3.27 | 39.94 | 55.68 | 46.50 | | | 75.94 | 5.77 | 27.80 | | | |
| 2004 | 3.95% | | 4.30% | 6.80% | 4.50% | | 19.38 | 3.40 | 42.65 | 58.19 | 49.12 | | | 78.94 | 6.00 | 29.00 | | | |
| 2005 | 3.95% | | 4.30% | 6.80% | 4.50% | | 20.15 | 3.54 | 45.55 | 60.80 | 51.91 | | | 82.06 | 6.24 | 30.25 | | | |
| 2006 | 3.95% | 0.207 | 4.30% | 6.80% | 4.50% | 311.74 | 20.94 | 3.68 | 48.65 | 63.54 | 54.85 | 109.17 | 838.76 | 85.30 | 6.48 | 31.55 | 178.68 | 32,993 | 54,000 |
| 2007 | 3.95% | 0.201 | 4.30% | 6.80% | 4.50% | 302.71 | 21.77 | 3.82 | 51.96 | 66.40 | 57.98 | 111.19 | 814.45 | 88.67 | 6.74 | 32.90 | 177.10 | 33,603 | 53,524 |
| 2008 | 3.95% | 0.194 | 4.30% | 6.80% | 4.50% | 292.16 | 22.63 | 3.97 | 55.49 | 69.39 | 61.28 | 113.17 | 786.09 | 92.17 | 7.00 | 34.32 | 175.00 | 34,202 | 52,888 |
| 2009 | 3.95% | 0.187 | 4.30% | 6.80% | 4.50% | 281.62 | 23.52 | 4.13 | 59.27 | 72.51 | 64.78 | 115.36 | 757.72 | 95.81 | 7.28 | 35.79 | 172.99 | 34,864 | 52,280 |
| 2010 | 3.95% | 0.181 | 4.30% | 6.80% | 4.50% | 272.59 | 24.45 | 4.29 | 63.30 | 75.77 | 68.49 | 118.00 | 733.41 | 99.60 | 7.57 | 37.33 | 171.69 | 35,662 | 51,888 |
| 2011 | 3.95% | 0.175 | 4.30% | 6.80% | 4.50% | 263.55 | 25.42 | 4.46 | 67.60 | 79.18 | 72.43 | 120.87 | 709.10 | 103.53 | 7.87 | 38.94 | 170.49 | 36,530 | 51,526 |
| 2012 | 3.95% | 0.169 | 4.30% | 6.80% | 4.50% | 254.51 | 26.42 | 4.64 | 72.20 | 82.75 | 76.59 | 123.99 | 684.79 | 107.62 | 8.18 | 40.61 | 169.40 | 37,473 | 51,196 |
| 2013 | 3.95% | 0.163 | 4.30% | 6.80% | 4.50% | 245.48 | 27.47 | 4.82 | 77.11 | 86.47 | 81.01 | 127.38 | 660.48 | 111.87 | 8.50 | 42.36 | 168.42 | 38,495 | 50,899 |
| 2014 | 3.95% | 0.158 | 4.30% | 6.80% | 4.50% | 237.95 | 28.55 | 5.01 | 82.35 | 90.36 | 85.69 | 131.26 | 640.22 | 116.29 | 8.84 | 44.18 | 168.16 | 39,671 | 50,822 |
| 2015 | 3.95% | 0.152 | 4.30% | 6.80% | 4.50% | 228.91 | 29.68 | 5.21 | 87.95 | 94.43 | 90.65 | 135.22 | 615.90 | 120.89 | 9.19 | 46.08 | 167.41 | 40,866 | 50,594 |
| 2016 | 3.95% | 0.146 | 4.30% | 6.80% | 4.50% | 219.88 | 30.85 | 5.42 | 93.93 | 98.68 | 95.91 | 139.49 | 591.59 | 125.66 | 9.55 | 48.06 | 166.78 | 42,156 | 50,404 |
| 2017 | 3.95% | 0.141 | 4.30% | 6.80% | 4.50% | 212.35 | 32.07 | 5.63 | 100.32 | 103.12 | 101.48 | 144.32 | 571.33 | 130.62 | 9.93 | 50.13 | 166.90 | 43,616 | 50,439 |
| 2018 | 3.95% | 0.135 | 4.30% | 6.80% | 4.50% | 203.31 | 33.34 | 5.86 | 107.14 | 107.76 | 107.40 | 149.27 | 547.02 | 135.78 | 10.32 | 52.28 | 166.53 | 45,112 | 50,328 |
| 2019 | 3.95% | 0.130 | 4.30% | 6.80% | 4.50% | 195.78 | 34.66 | 6.09 | 114.42 | 112.60 | 113.67 | 154.83 | 526.76 | 141.15 | 10.73 | 54.53 | 166.92 | 46,792 | 50,445 |
| 2020 | 3.95% | 0.124 | 4.30% | 6.80% | 4.50% | 186.74 | 36.02 | 6.33 | 122.20 | 117.67 | 120.32 | 160.55 | 502.45 | 146.72 | 11.15 | 56.88 | 166.83 | 48,521 | 50,420 |
| 2021 | 3.95% | 0.119 | *4.30%* | *6.80%* | *4.50%* | 179.21 | 37.45 | 6.58 | 130.51 | 122.97 | 127.37 | 166.92 | 482.19 | 152.52 | 11.59 | 59.32 | 167.52 | 50,448 | 50,627 |
| 2022 | 3.95% | 0.113 | *4.30%* | *6.80%* | *4.50%* | 170.18 | 38.93 | 6.84 | 139.39 | 128.50 | 134.85 | 173.52 | 457.88 | 158.54 | 12.05 | 61.87 | 167.74 | 52,440 | 50,695 |
| 2023 | 3.95% | 0.108 | *4.30%* | *6.80%* | *4.50%* | 162.65 | 40.46 | 7.11 | 148.87 | 134.28 | 142.79 | 180.81 | 437.62 | 164.81 | 12.52 | 64.53 | 168.75 | 54,645 | 50,999 |
| 2024 | 3.95% | 0.102 | *4.30%* | *6.80%* | *4.50%* | 153.61 | 42.06 | 7.39 | 158.99 | 140.33 | 151.21 | 188.38 | 413.30 | 171.32 | 13.02 | 67.31 | 169.31 | 56,933 | 51,168 |
| 2025 | 3.95% | 0.097 | *4.30%* | *6.80%* | *4.50%* | 146.08 | 43.72 | 7.68 | 169.80 | 146.64 | 160.15 | 196.72 | 393.04 | 178.08 | 13.53 | 70.20 | 170.66 | 59,453 | 51,578 |
| 2026 | 3.95% | 0.092 | *4.30%* | *6.80%* | *4.50%* | 138.55 | 45.45 | 7.98 | 181.35 | 153.24 | 169.64 | 205.63 | 372.78 | 185.12 | 14.07 | 73.22 | 172.20 | 62,144 | 52,043 |
| 2027 | 3.95% | 0.088 | *4.30%* | *6.80%* | *4.50%* | 132.53 | 47.25 | 8.30 | 193.68 | 160.14 | 179.70 | 215.36 | 356.58 | 192.43 | 14.62 | 76.37 | 174.55 | 65,087 | 52,753 |
| 2028 | 3.95% | 0.085 | *4.30%* | *6.80%* | *4.50%* | 128.01 | 49.11 | 8.63 | 206.85 | 167.34 | 190.39 | 225.97 | 344.42 | 200.03 | 15.20 | 79.65 | 177.72 | 68,294 | 53,711 |
| 2029 | 3.95% | 0.082 | *4.30%* | *6.80%* | *4.50%* | 123.49 | 51.05 | 8.97 | 220.92 | 174.87 | 201.73 | 237.26 | 332.26 | 207.93 | 15.80 | 83.08 | 181.10 | 71,706 | 54,732 |
| 2030 | 3.95% | 0.079 | *4.30%* | *6.80%* | *4.50%* | 118.97 | 53.07 | 9.32 | 235.94 | 182.74 | 213.77 | 249.28 | 320.11 | 216.14 | 16.42 | 86.65 | 184.69 | 75,337 | 55,818 |
| 2031 | 3.95% | 0.076 | *4.30%* | *6.80%* | *4.50%* | 114.46 | 55.17 | 9.69 | 251.98 | 190.96 | 226.56 | 262.06 | 307.95 | 224.68 | 17.07 | 90.38 | 188.52 | 79,201 | 56,974 |
| 2032 | 3.95% | 0.073 | *4.30%* | *6.80%* | *4.50%* | 109.94 | 57.34 | 10.07 | 269.12 | 199.56 | 240.13 | 275.67 | 295.80 | 233.56 | 17.75 | 94.26 | 192.58 | 83,312 | 58,202 |
| 2033 | 3.95% | 0.070 | *4.30%* | *6.80%* | *4.50%* | 105.42 | 59.61 | 10.47 | 287.42 | 208.54 | 254.55 | 290.14 | 283.64 | 242.78 | 18.45 | 98.32 | 196.89 | 87,686 | 59,504 |
| 2034 | 3.95% | 0.067 | *4.30%* | *6.80%* | *4.50%* | 100.90 | 61.96 | 10.88 | 306.96 | 217.92 | 269.86 | 305.53 | 271.48 | 252.37 | 19.18 | 102.54 | 201.45 | 92,338 | 60,883 |
| 2035 | 3.95% | 0.064 | *4.30%* | *6.80%* | *4.50%* | 96.38 | 64.41 | 11.31 | 327.83 | 227.73 | 286.12 | 321.91 | 259.33 | 262.34 | 19.93 | 106.95 | 206.29 | 97,288 | 62,344 |
| | | | | | | $2,076.20 | | | | | | $1,178 | $5,586 | | | | $1,469 | 355,902 | ###### |

1991 low fuel price

| quarter | #2 oil | coal |
|---|---|---|
| 1 | 29.47 | 48.28 |
| 2 | 24.53 | 46.99 |
| 3 | 24.34 | 47.55 |
| 4 | 24.24 | 47.54 |
| | **25.65** | **47.59** |

| | |
|---|---|
| apr | 2.2 |
| may | 2.17 |
| jun | 2.26 |
| jul | 2.32 |
| aug | 2.38 |
| sep | 2.45 |
| oct | 2.56 |
| | **2.33** |

**Comparison of economic carrying charges of IGCC and CGCC: base fuel case**

| | GNP Implicit Price Deflators | 30-Year Fixed Charge Factors | Coal Price Escalation | Gas Price Escalation | #2 Oil Price Escalation | Combined-Cycle Costs: CC Fixed Charge ($/kWyr) | CC Fixed O&M ($/kWyr) | CC Variable O&M ($/MWh) | CC Gas ($/MWh) | CC Oil ($/MWh) | CC Fuel ($/MWh) | Total Cost ($/MWh) | Coal-Gasification Combined-Cycle Costs: IGCC Fixed Charge ($/kWyr) | IGCC Fixed O&M ($/kWyr) | IGCC Variable O&M ($/MWh) | IGCC Fuel ($/MWh) | Total Cost ($/MWh) | Total Cost for 46 MW Unit: CC (M$) | IGCC (M$) | diff |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1990 | 4.56% | | | | | | 11.39 | | | | | | | 46.39 | | | | | | |
| 1991 | 2.98% | | | | | | 11.73 | 2.06 | 19.30 | 36.65 | 26.53 | | | 47.77 | 3.63 | 17.20 | | | | |
| 1992 | 2.98% | | 4.59% | 3.12% | -0.77% | | 12.08 | 2.12 | 19.91 | 36.37 | 26.77 | | | 49.20 | 3.74 | 17.99 | | | | |
| 1993 | 3.28% | | 4.43% | 13.63% | 6.46% | | 12.48 | 2.19 | 22.62 | 38.72 | 29.33 | | | 50.81 | 3.86 | 18.78 | | | | |
| 1994 | 3.48% | | 6.15% | 11.00% | 5.49% | | 12.91 | 2.27 | 25.11 | 40.85 | 31.66 | | | 52.58 | 4.00 | 19.94 | | | | |
| 1995 | 3.95% | | 5.58% | 12.38% | 7.21% | | 13.42 | 2.36 | 28.21 | 43.79 | 34.70 | | | 54.65 | 4.15 | 21.05 | | | | |
| 1996 | 4.15% | | 5.15% | 8.84% | 8.68% | | 13.98 | 2.45 | 30.71 | 47.59 | 37.74 | | | 56.92 | 4.33 | 22.13 | | | | |
| 1997 | 4.25% | | 5.03% | 9.56% | 9.86% | | 14.57 | 2.56 | 33.64 | 52.28 | 41.41 | | | 59.34 | 4.51 | 23.25 | | | | |
| 1998 | 4.21% | | 5.06% | 9.14% | 8.79% | | 15.18 | 2.67 | 36.72 | 56.88 | 45.12 | | | 61.84 | 4.70 | 24.42 | | | | |
| 1999 | 4.33% | | 5.21% | 8.94% | 8.34% | | 15.84 | 2.78 | 40.00 | 61.62 | 49.01 | | | 64.52 | 4.90 | 25.70 | | | | |
| 2000 | 4.35% | | 5.30% | 8.37% | 8.13% | | 16.53 | 2.90 | 43.35 | 66.63 | 53.05 | | | 67.32 | 5.12 | 27.06 | | | | |
| 2001 | 4.39% | | 5.11% | 8.13% | 7.92% | | 17.26 | 3.03 | 46.87 | 71.91 | 57.31 | | | 70.28 | 5.34 | 28.44 | | | | |
| 2002 | 3.95% | | 5.21% | 9.70% | 7.40% | | 17.94 | 3.15 | 51.42 | 77.23 | 62.18 | | | 73.06 | 5.55 | 29.92 | | | | |
| 2003 | 3.95% | | 5.02% | 9.29% | 7.03% | | 18.65 | 3.27 | 56.20 | 82.66 | 67.22 | | | 75.94 | 5.77 | 31.42 | | | | |
| 2004 | 3.95% | | 4.86% | 8.44% | 7.07% | | 19.38 | 3.40 | 60.94 | 88.51 | 72.43 | | | 78.94 | 6.00 | 32.95 | | | | |
| 2005 | 3.95% | | 5.15% | 7.72% | 6.69% | | 20.15 | 3.54 | 65.65 | 94.43 | 77.64 | | | 82.06 | 6.24 | 34.65 | | | | |
| 2006 | 3.95% | 0.116 | 5.10% | 7.59% | 6.24% | 174.82 | 20.94 | 3.68 | 70.63 | 100.32 | 83.00 | 116.48 | 470.37 | 85.30 | 6.48 | 36.42 | 127.48 | 35.20 | 38.53 | (3.32) |
| 2007 | 3.95% | 0.121 | 5.04% | 7.30% | 6.94% | 181.73 | 21.77 | 3.82 | 75.78 | 107.28 | 88.91 | 123.71 | 488.95 | 88.67 | 6.74 | 38.25 | 132.91 | 37.39 | 40.17 | (2.78) |
| 2008 | 3.95% | 0.125 | 5.05% | 7.42% | 6.61% | 188.91 | 22.63 | 3.97 | 81.41 | 114.37 | 95.14 | 131.32 | 508.27 | 92.17 | 7.00 | 40.18 | 138.58 | 39.69 | 41.88 | (2.19) |
| 2009 | 3.95% | 0.130 | 4.88% | 7.26% | 6.03% | 196.37 | 23.52 | 4.13 | 87.32 | 121.27 | 101.46 | 139.07 | 528.34 | 95.81 | 7.28 | 42.14 | 144.43 | 42.03 | 43.65 | (1.62) |
| 2010 | 3.95% | 0.136 | 4.94% | 7.32% | 6.17% | 204.12 | 24.45 | 4.29 | 93.71 | 128.75 | 108.31 | 147.40 | 549.21 | 99.60 | 7.57 | 44.23 | 150.55 | 44.55 | 45.50 | (0.95) |
| 2011 | 3.95% | 0.141 | 5.11% | 6.40% | 5.48% | 212.19 | 25.42 | 4.46 | 99.71 | 135.81 | 114.75 | 155.38 | 570.91 | 103.53 | 7.87 | 46.49 | 157.01 | 46.96 | 47.45 | (0.49) |
| 2012 | 3.95% | 0.146 | 5.03% | 5.84% | 5.31% | 220.57 | 26.42 | 4.64 | 105.53 | 143.02 | 121.15 | 163.39 | 593.46 | 107.62 | 8.18 | 48.82 | 163.71 | 49.38 | 49.48 | (0.10) |
| 2013 | 3.95% | 0.152 | 5.11% | 5.45% | 5.03% | 229.28 | 27.47 | 4.82 | 111.28 | 150.21 | 127.50 | 171.41 | 616.90 | 111.87 | 8.50 | 51.32 | 170.74 | 51.80 | 51.60 | 0.20 |
| 2014 | 3.95% | 0.158 | 5.10% | 5.41% | 5.24% | 238.34 | 28.55 | 5.01 | 117.30 | 158.08 | 134.29 | 179.93 | 641.27 | 116.29 | 8.84 | 53.94 | 178.08 | 54.38 | 53.82 | 0.56 |
| 2015 | 3.95% | 0.165 | 5.08% | 5.35% | 5.24% | 247.75 | 29.68 | 5.21 | 123.58 | 166.37 | 141.41 | 188.85 | 666.60 | 120.89 | 9.19 | 56.68 | 185.72 | 57.07 | 56.13 | 0.94 |
| 2016 | 3.95% | 0.171 | 5.06% | 5.88% | 5.03% | 257.54 | 30.85 | 5.42 | 130.84 | 174.74 | 149.13 | 198.45 | 692.93 | 125.66 | 9.55 | 59.54 | 193.69 | 59.97 | 58.54 | 1.44 |
| 2017 | 3.95% | 0.178 | 5.09% | 5.64% | 5.16% | 267.71 | 32.07 | 5.63 | 138.22 | 183.75 | 157.19 | 208.46 | 720.30 | 130.62 | 9.93 | 62.58 | 202.02 | 63.00 | 61.05 | 1.95 |
| 2018 | 3.95% | 0.185 | 5.06% | 5.60% | 5.04% | 278.29 | 33.34 | 5.86 | 145.96 | 193.01 | 165.57 | 218.85 | 748.75 | 135.78 | 10.32 | 65.74 | 210.69 | 66.14 | 63.68 | 2.47 |
| 2019 | 3.95% | 0.192 | 5.13% | 5.55% | 5.03% | 289.28 | 34.66 | 6.09 | 154.07 | 202.72 | 174.34 | 229.73 | 778.33 | 141.15 | 10.73 | 69.11 | 219.79 | 69.43 | 66.42 | 3.00 |
| 2020 | 3.95% | 0.200 | 5.08% | 5.33% | 5.24% | 300.71 | 36.02 | 6.33 | 162.28 | 213.34 | 183.55 | 241.13 | 809.07 | 146.72 | 11.15 | 72.63 | 229.25 | 72.88 | 69.28 | 3.59 |
| 2021 | 3.95% | 0.208 | 5.08% | 5.33% | 5.24% | 312.58 | 37.45 | 6.58 | 170.93 | 224.52 | 193.26 | 253.11 | 841.03 | 152.52 | 11.59 | 76.31 | 239.13 | 76.50 | 72.27 | 4.23 |
| 2022 | 3.95% | 0.216 | 5.08% | 5.33% | 5.24% | 324.93 | 38.93 | 6.84 | 180.04 | 236.29 | 203.47 | 265.69 | 874.25 | 158.54 | 12.05 | 80.19 | 249.44 | 80.30 | 75.38 | 4.91 |
| 2023 | 3.95% | 0.224 | 5.08% | 5.33% | 5.24% | 337.76 | 40.46 | 7.11 | 189.63 | 248.67 | 214.23 | 278.91 | 908.78 | 164.81 | 12.52 | 84.26 | 260.20 | 84.29 | 78.64 | 5.66 |
| 2024 | 3.95% | 0.233 | 5.08% | 5.33% | 5.24% | 351.11 | 42.06 | 7.39 | 199.74 | 261.70 | 225.56 | 292.79 | 944.68 | 171.32 | 13.02 | 88.55 | 271.42 | 88.49 | 82.03 | 6.46 |
| 2025 | 3.95% | 0.242 | 5.08% | 5.33% | 5.24% | 364.98 | 43.72 | 7.68 | 210.39 | 275.41 | 237.48 | 307.37 | 981.99 | 178.08 | 13.53 | 93.04 | 283.15 | 92.89 | 85.57 | 7.32 |
| 2026 | 3.95% | 0.252 | 5.08% | 5.33% | 5.24% | 379.39 | 45.45 | 7.98 | 221.60 | 289.84 | 250.04 | 322.68 | 1020.78 | 185.12 | 14.07 | 97.77 | 295.38 | 97.52 | 89.27 | 8.25 |
| 2027 | 3.95% | 0.262 | 5.08% | 5.33% | 5.24% | 394.38 | 47.25 | 8.30 | 233.41 | 305.03 | 263.25 | 338.77 | 1061.10 | 192.43 | 14.62 | 102.74 | 308.15 | 102.38 | 93.13 | 9.25 |
| 2028 | 3.95% | 0.272 | 5.08% | 5.33% | 5.24% | 409.96 | 49.11 | 8.63 | 245.85 | 321.02 | 277.17 | 355.67 | 1103.02 | 200.03 | 15.20 | 107.96 | 321.49 | 107.49 | 97.16 | 10.33 |
| 2029 | 3.95% | 0.283 | 5.08% | 5.33% | 5.24% | 426.15 | 51.05 | 8.97 | 258.96 | 337.84 | 291.82 | 373.42 | 1146.58 | 207.93 | 15.80 | 113.44 | 335.41 | 112.86 | 101.37 | 11.49 |
| 2030 | 3.95% | 0.294 | 5.08% | 5.33% | 5.24% | 442.98 | 53.07 | 9.32 | 272.76 | 355.54 | 307.25 | 392.07 | 1191.87 | 216.14 | 16.42 | 119.20 | 349.94 | 118.49 | 105.76 | 12.73 |
| 2031 | 3.95% | 0.306 | 5.08% | 5.33% | 5.24% | 460.48 | 55.17 | 9.69 | 287.30 | 374.17 | 323.49 | 411.67 | 1238.95 | 224.68 | 17.07 | 125.26 | 365.11 | 124.41 | 110.34 | 14.07 |
| 2032 | 3.95% | 0.318 | 5.08% | 5.33% | 5.24% | 478.67 | 57.34 | 10.07 | 302.61 | 393.78 | 340.60 | 432.25 | 1287.89 | 233.56 | 17.75 | 131.62 | 380.94 | 130.64 | 115.13 | 15.51 |
| 2033 | 3.95% | 0.330 | 5.08% | 5.33% | 5.24% | 497.58 | 59.61 | 10.47 | 318.74 | 414.41 | 358.60 | 453.88 | 1338.76 | 242.78 | 18.45 | 138.31 | 397.48 | 137.17 | 120.13 | 17.05 |
| 2034 | 3.95% | 0.343 | 5.08% | 5.33% | 5.24% | 517.23 | 61.96 | 10.88 | 335.73 | 436.13 | 377.56 | 476.60 | 1391.64 | 252.37 | 19.18 | 145.33 | 414.74 | 144.04 | 125.34 | 18.69 |
| 2035 | 3.95% | 0.357 | 5.08% | 5.33% | 5.24% | 537.66 | 64.41 | 11.31 | 353.62 | 458.98 | 397.52 | 500.47 | 1446.61 | 262.34 | 19.93 | 152.72 | 432.77 | 151.25 | 130.79 | 20.46 |
| | | | | | | $2,076.20 | | | | | | $1,587.46 | | | | | $1,562.18 | | | |

| | |
|---|---|
| ECONOMIC CARRYING CHARGE | 11.61% |
| ECONOMIC CARRYING CHARGE FOR IGCC | 11.61% |

GMPXX2.XLS ecc 11/6/97 4:22 AM

**Comparison of economic carrying charges of IGCC and CGCC: low fuel case**

| | | | | | | Combined-Cycle Costs | | | | | | | Coal-Gasification Combined-Cycle Costs | | | | | Total Cost for 46 MW Unit | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | GNP Implicit Price Deflators | 30-Year Fixed Charge Factors | Coal Price Escalation | Gas Price Escalation | #2 Oil Price Escalation | CC Fixed Charge ($/kWyr) | CC Fixed O&M ($/kWyr) | CC Variable O&M ($/MWh) | CC Gas ($/MWh) | CC Oil ($/MWh) | CC Fuel ($/MWh) | Total Cost ($/MWh) | IGCC Fixed Charge ($/kWyr) | IGCC Fixed O&M ($/kWyr) | IGCC Variable O&M ($/MWh) | IGCC Fuel ($/MWh) | Total Cost ($/MWh) | CC (M$) | IGCC (M$) | diff |
| 1990 | 4.56% | | | | | | 11.39 | | | | | | | 46.39 | | | | | | |
| 1991 | 2.98% | | | | | | 11.73 | 2.06 | 19.14 | 36.20 | 26.25 | | | 47.77 | 3.63 | 16.86 | | | | |
| 1992 | 2.98% | | 4.10% | 1.20% | -6.30% | | 12.08 | 2.12 | 19.37 | 33.92 | 25.43 | | | 49.20 | 3.74 | 17.55 | | | | |
| 1993 | 3.28% | | 4.00% | 6.80% | 5.70% | | 12.48 | 2.19 | 20.69 | 35.85 | 27.01 | | | 50.81 | 3.86 | 18.25 | | | | |
| 1994 | 3.48% | | 4.30% | 6.80% | 4.50% | | 12.91 | 2.27 | 22.09 | 37.47 | 28.50 | | | 52.58 | 4.00 | 19.03 | | | | |
| 1995 | 3.95% | | 4.30% | 6.80% | 4.50% | | 13.42 | 2.36 | 23.59 | 39.15 | 30.08 | | | 54.65 | 4.15 | 19.85 | | | | |
| 1996 | 4.15% | | 4.30% | 6.80% | 4.50% | | 13.98 | 2.45 | 25.20 | 40.91 | 31.75 | | | 56.92 | 4.33 | 20.71 | | | | |
| 1997 | 4.25% | | 4.30% | 6.80% | 4.50% | | 14.57 | 2.56 | 26.91 | 42.76 | 33.51 | | | 59.34 | 4.51 | 21.60 | | | | |
| 1998 | 4.21% | | 4.30% | 6.80% | 4.50% | | 15.18 | 2.67 | 28.74 | 44.68 | 35.38 | | | 61.84 | 4.70 | 22.53 | | | | |
| 1999 | 4.33% | | 4.30% | 6.80% | 4.50% | | 15.84 | 2.78 | 30.70 | 46.69 | 37.36 | | | 64.52 | 4.90 | 23.49 | | | | |
| 2000 | 4.35% | | 4.30% | 6.80% | 4.50% | | 16.53 | 2.90 | 32.78 | 48.79 | 39.45 | | | 67.32 | 5.12 | 24.50 | | | | |
| 2001 | 4.39% | | 4.30% | 6.80% | 4.50% | | 17.26 | 3.03 | 35.01 | 50.99 | 41.67 | | | 70.28 | 5.34 | 25.56 | | | | |
| 2002 | 3.95% | | 4.30% | 6.80% | 4.50% | | 17.94 | 3.15 | 37.39 | 53.28 | 44.01 | | | 73.06 | 5.55 | 26.66 | | | | |
| 2003 | 3.95% | | 4.30% | 6.80% | 4.50% | | 18.65 | 3.27 | 39.94 | 55.68 | 46.50 | | | 75.94 | 5.77 | 27.80 | | | | |
| 2004 | 3.95% | | 4.30% | 6.80% | 4.50% | | 19.38 | 3.40 | 42.65 | 58.19 | 49.12 | | | 78.94 | 6.00 | 29.00 | | | | |
| 2005 | 3.95% | | 4.30% | 6.80% | 4.50% | | 20.15 | 3.54 | 45.55 | 60.80 | 51.91 | | | 82.06 | 6.24 | 30.25 | | | | |
| 2006 | 3.95% | 0.116 | 4.30% | 6.80% | 4.50% | 174.82 | 20.94 | 3.68 | 48.65 | 63.54 | 54.85 | 88.33 | 470.37 | 85.30 | 6.48 | 31.55 | 122.61 | 26.70 | 37.05 | (10.36) |
| 2007 | 3.95% | 0.121 | 4.30% | 6.80% | 4.50% | 181.73 | 21.77 | 3.82 | 51.96 | 66.40 | 57.98 | 92.77 | 488.95 | 88.67 | 6.74 | 32.90 | 127.56 | 28.04 | 38.55 | (10.51) |
| 2008 | 3.95% | 0.125 | 4.30% | 6.80% | 4.50% | 188.91 | 22.63 | 3.97 | 55.49 | 69.39 | 61.28 | 97.45 | 508.27 | 92.17 | 7.00 | 34.32 | 132.71 | 29.45 | 40.11 | (10.66) |
| 2009 | 3.95% | 0.130 | 4.30% | 6.80% | 4.50% | 196.37 | 23.52 | 4.13 | 59.27 | 72.51 | 64.78 | 102.38 | 528.34 | 95.81 | 7.28 | 35.79 | 138.07 | 30.94 | 41.73 | (10.79) |
| 2010 | 3.95% | 0.136 | 4.30% | 6.80% | 4.50% | 204.12 | 24.45 | 4.29 | 63.30 | 75.77 | 68.49 | 107.58 | 549.21 | 99.60 | 7.57 | 37.33 | 143.65 | 32.51 | 43.42 | (10.90) |
| 2011 | 3.95% | 0.141 | 4.30% | 6.80% | 4.50% | 212.19 | 25.42 | 4.46 | 67.60 | 79.18 | 72.43 | 113.06 | 570.91 | 103.53 | 7.87 | 38.94 | 149.46 | 34.17 | 45.17 | (11.00) |
| 2012 | 3.95% | 0.146 | 4.30% | 6.80% | 4.50% | 220.57 | 26.42 | 4.64 | 72.20 | 82.75 | 76.59 | 118.83 | 593.46 | 107.62 | 8.18 | 40.61 | 155.50 | 35.91 | 46.99 | (11.08) |
| 2013 | 3.95% | 0.152 | 4.30% | 6.80% | 4.50% | 229.28 | 27.47 | 4.82 | 77.11 | 86.47 | 81.01 | 124.91 | 616.90 | 111.87 | 8.50 | 42.36 | 161.78 | 37.75 | 48.89 | (11.14) |
| 2014 | 3.95% | 0.158 | 4.30% | 6.80% | 4.50% | 238.34 | 28.55 | 5.01 | 82.35 | 90.36 | 85.69 | 131.32 | 641.27 | 116.29 | 8.84 | 44.18 | 168.32 | 39.69 | 50.87 | (11.18) |
| 2015 | 3.95% | 0.165 | 4.30% | 6.80% | 4.50% | 247.75 | 29.68 | 5.21 | 87.95 | 94.43 | 90.65 | 138.09 | 666.60 | 120.89 | 9.19 | 46.08 | 175.12 | 41.73 | 52.93 | (11.19) |
| 2016 | 3.95% | 0.171 | 4.30% | 6.80% | 4.50% | 257.54 | 30.85 | 5.42 | 93.93 | 98.68 | 95.91 | 145.22 | 692.93 | 125.66 | 9.55 | 48.06 | 182.20 | 43.89 | 55.07 | (11.18) |
| 2017 | 3.95% | 0.178 | 4.30% | 6.80% | 4.50% | 267.71 | 32.07 | 5.63 | 100.32 | 103.12 | 101.48 | 152.74 | 720.30 | 130.62 | 9.93 | 50.13 | 189.57 | 46.16 | 57.29 | (11.13) |
| 2018 | 3.95% | 0.185 | 4.30% | 6.80% | 4.50% | 278.29 | 33.34 | 5.86 | 107.14 | 107.76 | 107.40 | 160.68 | 748.75 | 135.78 | 10.32 | 52.28 | 197.23 | 48.56 | 59.61 | (11.05) |
| 2019 | 3.95% | 0.192 | 4.30% | 6.80% | 4.50% | 289.28 | 34.66 | 6.09 | 114.42 | 112.60 | 113.67 | 169.06 | 778.33 | 141.15 | 10.73 | 54.53 | 205.21 | 51.09 | 62.02 | (10.92) |
| 2020 | 3.95% | 0.200 | 4.30% | 6.80% | 4.50% | 300.71 | 36.02 | 6.33 | 122.20 | 117.67 | 120.32 | 177.90 | 809.07 | 146.72 | 11.15 | 56.88 | 213.50 | 53.76 | 64.52 | (10.76) |
| 2021 | 3.95% | 0.208 | *4.30%* | 6.80% | *4.50%* | 312.58 | 37.45 | 6.58 | 130.51 | 122.97 | 127.37 | 187.22 | 841.03 | 152.52 | 11.59 | 59.32 | 222.13 | 56.58 | 67.13 | (10.55) |
| 2022 | 3.95% | 0.216 | *4.30%* | 6.80% | *4.50%* | 324.93 | 38.93 | 6.84 | 139.39 | 128.50 | 134.85 | 197.07 | 874.25 | 158.54 | 12.05 | 61.87 | 231.12 | 59.56 | 69.85 | (10.29) |
| 2023 | 3.95% | 0.224 | *4.30%* | 6.80% | *4.50%* | 337.76 | 40.46 | 7.11 | 148.87 | 134.28 | 142.79 | 207.47 | 908.78 | 164.81 | 12.52 | 64.53 | 240.46 | 62.70 | 72.67 | (9.97) |
| 2024 | 3.95% | 0.233 | *4.30%* | 6.80% | *4.50%* | 351.11 | 42.06 | 7.39 | 158.99 | 140.33 | 151.21 | 218.44 | 944.68 | 171.32 | 13.02 | 67.31 | 250.19 | 66.02 | 75.61 | (9.59) |
| 2025 | 3.95% | 0.242 | *4.30%* | 6.80% | *4.50%* | 364.98 | 43.72 | 7.68 | 169.80 | 146.64 | 160.15 | 230.04 | 981.99 | 178.08 | 13.53 | 70.20 | 260.30 | 69.52 | 78.67 | (9.15) |
| 2026 | 3.95% | 0.252 | *4.30%* | 6.80% | *4.50%* | 379.39 | 45.45 | 7.98 | *181.35* | *153.24* | *169.64* | *242.28* | 1020.78 | 185.12 | 14.07 | *73.22* | *270.83* | 73.22 | 81.85 | (8.63) |
| 2027 | 3.95% | 0.262 | *4.30%* | 6.80% | *4.50%* | 394.38 | 47.25 | 8.30 | *193.68* | *160.14* | *179.70* | *255.22* | 1061.10 | 192.43 | 14.62 | *76.37* | *281.79* | 77.13 | 85.16 | (8.03) |
| 2028 | 3.95% | 0.272 | *4.30%* | 6.80% | *4.50%* | 409.96 | 49.11 | 8.63 | *206.85* | *167.34* | *190.39* | *268.89* | 1103.02 | 200.03 | 15.20 | *79.65* | *293.18* | 81.26 | 88.61 | (7.34) |
| 2029 | 3.95% | 0.283 | *4.30%* | 6.80% | *4.50%* | 426.15 | 51.05 | 8.97 | *220.92* | *174.87* | *201.73* | *283.33* | 1146.58 | 207.93 | 15.80 | *83.08* | *305.04* | 85.63 | 92.19 | (6.56) |
| 2030 | 3.95% | 0.294 | *4.30%* | 6.80% | *4.50%* | 442.98 | 53.07 | 9.32 | *235.94* | *182.74* | *213.77* | *298.60* | 1191.87 | 216.14 | 16.42 | *86.65* | *317.38* | 90.24 | 95.92 | (5.68) |
| 2031 | 3.95% | 0.306 | *4.30%* | 6.80% | *4.50%* | 460.48 | 55.17 | 9.69 | *251.98* | *190.96* | *226.56* | *314.73* | 1238.95 | 224.68 | 17.07 | *90.38* | *330.22* | 95.12 | 99.80 | (4.68) |
| 2032 | 3.95% | 0.318 | *4.30%* | 6.80% | *4.50%* | 478.67 | 57.34 | 10.07 | *269.12* | *199.56* | *240.13* | *331.79* | 1287.89 | 233.56 | 17.75 | *94.26* | *343.58* | 100.27 | 103.84 | (3.56) |
| 2033 | 3.95% | 0.330 | *4.30%* | 6.80% | *4.50%* | 497.58 | 59.61 | 10.47 | *287.42* | *208.54* | *254.55* | *349.83* | 1338.76 | 242.78 | 18.45 | *98.32* | *357.49* | 105.72 | 108.04 | (2.31) |
| 2034 | 3.95% | 0.343 | *4.30%* | 6.80% | *4.50%* | 517.23 | 61.96 | 10.88 | *306.96* | *217.92* | *269.86* | *368.90* | 1391.64 | 252.37 | 19.18 | *102.54* | *371.95* | 111.49 | 112.41 | (0.92) |
| 2035 | 3.95% | 0.357 | *4.30%* | 6.80% | *4.50%* | 537.66 | 64.41 | 11.31 | *327.83* | *227.73* | *286.12* | *389.08* | 1446.61 | 262.34 | 19.93 | *106.95* | *387.00* | 117.59 | 116.96 | 0.63 |
| | | | | | | $2,076.20 | $249 | $43.68 | $769 | $795 | $780 | $1,178 | $5,586 | $1,013 | $77 | $387 | $1,469 | | | |