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ANALYSIS OF NATURAL GAS SUPPLY STRATEGIES AT FORT DRUM

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PREFACE

The goal of the U.S. Department of Energy Federal Energy Management Program (DOE-FEMP) is to facilitate energy-efficiency improvements at federal facilities. This is accomplished by a balanced program of technology development, energy efficiency resource and energy supply assessment, and facility modernization. Technology development focuses upon the tools and procedures used to identify and evaluate efficiency improvements, such as the federal life-cycle cost analyses. For efficiency resource and energy supply assessment, FEMP provides metering equipment and trained analysts to federal agencies exhibiting a commitment to understand and improve energy use efficiency and reduce energy costs.

The U.S. Army Forces Command (FORSCOM) has tasked Pacific Northwest Laboratory (PNL), as the lead laboratory supporting the FEMP mission, to provide technical assistance to modernize energy systems at FORSCOM installations. Under this task, PNL has undertaken an evaluation of the supply options to provide natural gas to Fort Drum. The analysis examined several options for natural gas supply, and the results will be used by decision makers to determine the most cost-effective strategy for future natural gas supply to the site.

EXECUTIVE SUMMARY

Fort Drum, an Army Forces Command (FORSCOM) installation near Watertown, New York, consumed over 2.4 million therms of natural gas in fiscal year 1991, at a cost of nearly $1 million. Fort Drum staff have been aggressive in securing least-cost gas supply strategies, as evidenced by the fact that their current gas supply configuration reduced costs by nearly 30% from the next-best alternative offered by Niagara Mohawk Power Corporation (NMPC). This analysis investigates strategies for Fort Drum to acquire a reliable natural gas supply while reducing its gas supply costs still further.

The analysis results indicate that Fort Drum can reduce its gas supply costs significantly while maintaining a reliable supply. The following is a summary of the results.

- The *best immediately implementable* strategy is for Fort Drum to purchase its gas from the Defense Fuel Supply Center (DFSC) and transport it under the large volume interruptible rate (the SC5-I rate), use NMPC SC6 supplemental service when the DFSC is curtailed, and build a propane-air mixing station to provide supplemental gas service during NMPC interruptions. This strategy will be referred to as <u>Strategy 11</u>. Strategy 11 has an estimated net present value of $7.4 million, and estimated annual energy cost savings of $288,000 at current fuel and electricity prices.

- The strategy with the *largest net present value* (NPV) is to move gas through the Iroquois pipeline to NMPC, and to switch to NMPC's large volume interruptible transportation rate (the SC5-I rate). Fort Drum should build a propane-air mixing station to provide supplemental gas service during interruptions. This strategy will be referred to as <u>Strategy 2</u>. This strategy has an NPV of $8.4 million and annual energy cost savings of $353,000 at current fuel and electricity prices. However, this strategy is not immediately available since Iroquois will not complete its pipeline hookup with NMPC until 1994. Iroquois is also not accepting new customers until November 1993.

- We recommend that Fort Drum implement <u>Strategy 11</u> by building the propane-air station and switching to the NMPC SC5-I rate as soon as contractual obligations allows it to do so, while beginning the process of implementing <u>Strategy 2</u>, so that once Iroquois is accepting customers and the Iroquois-NMPC pipeline is open, Fort Drum will be able to switch easily to the largest NPV strategy.

It should be noted that the costs and savings given above are for gas supply to the New Fort only and that conversion of the Old Fort to natural gas is not included. The analysis was also performed for the Entire Fort, which assumes that conversion of the Old Fort to natural gas occurs.

The analysis proceeded by defining the components of supply (gas purchase, gas transport, supplemental fuel supply); identifying alternative options for each supply component; constructing gas supply strategies from different combinations of the options available for each supply component; and calculating the life-cycle costs of each supply strategy under a set of different scenarios reflecting the uncertainty of future events. This complex procedure is illustrated in a flowchart in Figure S.1.

Table S.1 gives the analysis results for Strategies 11 and 2 as well as for the additional strategies analyzed. The results reported in Table S.1 are for the Base Case-New Fort scenario, which assumes that the conversion of the Old Fort to natural gas does not occur; that real energy prices escalate in accordance with the Department of Energy's (DOE's) price forecasts ("Energy Prices and Discount Factors," NISTIR 85-3273-5, 10/91); and that NMPC is able to continue to supply its interruptible gas customers without any interruptions. Section 4 contains more details regarding all of the scenarios explored and the assumptions incorporated within them.

The analysis was also performed for two additional gas pricing scenarios. The High Gas Price Forecast scenario assumes that real gas prices escalate at a rate double that assumed by DOE, based on a recent Gas Research Institute (GRI) gas price forecast. Electricity prices are assumed to escalate at the DOE escalation rate.

Under the NMPC Interruption scenario, gas prices are assumed to escalate according to the DOE escalation rate, but NMPC curtails gas use to its interruptible customers, forcing them to utilize their supplemental fuels. Under this scenario, it is assumed that NMPC interrupts its gas service for a total of 264 hours in the peak demand period of October through January.

Both the High Gas Price Forecast scenario and the NMPC Interruption scenario are run for the New Fort and the Entire Fort. The analysis scenarios are described in detail in Section 4.

Table S.2 gives the analysis results for all of the strategies under the High Gas Price Forecast scenario for the New Fort, and Table S.3 gives the results for the NMPC Interruption scenario for the New Fort. In Table S.2, the estimated NPV of Strategy 11 rises to $9.1 million from the $7.4 million for the base case. Strategy 2 likewise shows an increase in NPV. Note that the annual energy cost savings are the same as in the base case. This is because this scenario refers to a higher rate of escalation of <u>future</u> prices, but assumes the same <u>current</u> gas price as the base case. In Table S.3, the estimated net present value of Strategy 11 decreases from the base case to $5.6 million, but the estimated net present value of Strategy 2 remains the same as for the base case.

For the Entire Fort, the analysis includes the planned conversion of the Old Fort from propane and fuel oil to natural gas, resulting in approximately a 140% increase in gas consumption over current use.

Under the High Gas Price Forecast scenario, the estimated NPV of Strategy 11 would rise to over $25 million. Under the NMPC Interruption scenario, the estimated NPV of Strategy 11 would fall to approximately $18 million, and the annual fuel cost savings would be $791,000. Tables S.4 through S.6 present the analysis results for all of the strategies for the Entire Fort. Strategy 2 remains the highest NPV strategy, with an NPV of almost $24 million and annual energy cost savings of over $1.1 million. Strategy 11 remains the best immediately implementable strategy, with an NPV of over $21 million and annual energy cost savings of $1 million. (Note that neither Strategies 2, 3, nor Strategy 8 can be implemented until Iroquois Gas Transmission Corporation is accepting new customers. It is possible that Strategy 8 could never be implemented, due to possible regulatory constraints.)

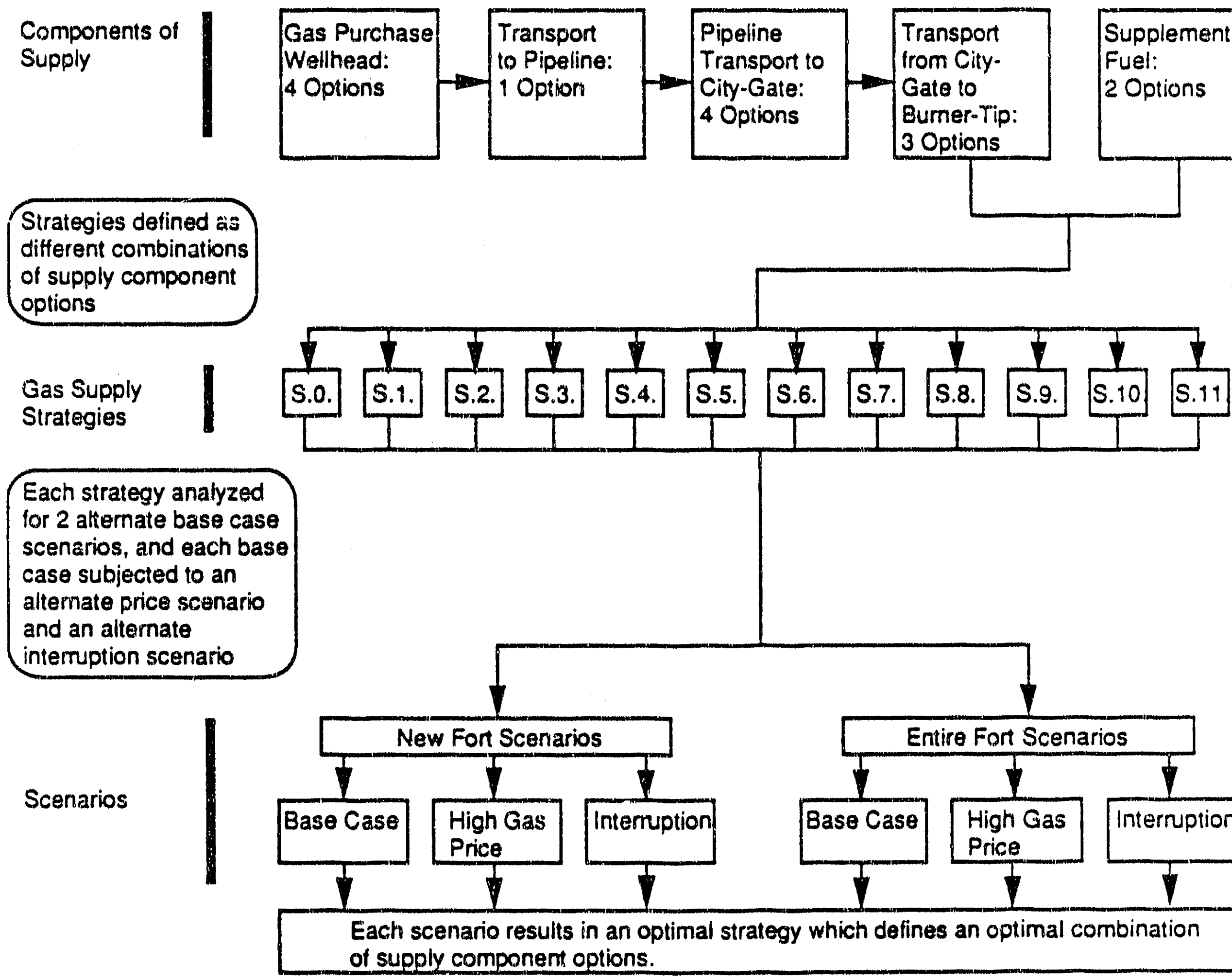

FIGURE S.1. Flowchart of Analysis Process

TABLE S.1. Analysis Results: Base Case-New Fort (1992 $ thousands)

	Strategy	NPV of Investment	Annual Energy Cost Savings	Initial Capital Cost
1.	Large Volume Interruptible Rate with Propane Air Supplemental	5,461	192	950
2.	Interruptible Transportation, Iroquois to NMPC, with Propane Air Supplemental	8,416	353	950
3.	Interruptible Transportation, Iroquois to CNG to NMPC, with Propane Air Supplemental	6,754	261	950
4.	Interruptible Transportation, with NMPC Supplemental	4,167	117	950
5.	Interruptible Transportation, with Propane Air Supplemental	3,379	21	950
6.	Firm Transportation, Iroquois to NMPC, with NMPC Supplemental	3,859	214	0
7.	Firm Transportation, Iroquois to CNG to NMPC, with NMPC Supplemental	2,197	122	0
8.	Pipeline Connecting Iroquois to Fort Drum	-1,414	668	13,700
9.	DFSC, Firm Transportation, with NMPC Supplemental	2,856	160	0
10.	DFSC, Interruptible Transportation, with Propane Air Supplemental	6,889	353	950
11.	DFSC, Interruptible Transportation, with NMPC Supplemental	7,447	288	950

TABLE S.2. Analysis Results: High Gas Price Forecast-New Fort (1992 $ thousands)

	Strategy	NPV of Investment	Annual Energy Cost Savings	Initial Capital Cost
1.	Large Volume Interruptible Rate with Propane Air Supplemental	6,616	192	950
2.	Interruptible Transportation, Iroquois to NMPC, with Propane Air Supplemental	10,152	353	950
3.	Interruptible Transportation, Iroquois to CNG to NMPC, with Propane Air Supplemental	8,190	261	950
4.	Interruptible Transportation, with NMPC Supplemental	5,121	117	950
5.	Interruptible Transportation, with Propane Air Supplemental	5,288	21	950
6.	Firm Transportation, Iroquois to NMPC, with NMPC Supplemental	4,571	214	0
7.	Firm Transportation, Iroquois to CNG to NMPC, with NMPC Supplemental	2,609	122	0
8.	Pipeline Connecting Iroquois to Fort Drum	673	668	13,700
9.	DFSC, Firm Transportation, with NMPC Supplemental	3,366	160	0
10.	DFSC, Interruptible Transportation, with Propane Air Supplemental	8,679	244	950
11.	DFSC, Interruptible Transportation, with NMPC Supplemental	9,167	288	950

TABLE S.3. Analysis Results: NMPC Interruption-New Fort (1992 $ thousands)

	Strategy	NPV of Investment	Annual Energy Cost Savings	Initial Capital Cost
1.	Large Volume Interruptible Rate with Propane Air Supplemental	4,882	147	950
2.	Interruptible Transportation, Iroquois to NMPC, with Propane Air Supplemental	8,416	353	950
3.	Interruptible Transportation, Iroquois to CNG to NMPC, with Propane Air Supplemental	6,754	261	950
4.	Interruptible Transportation, with NMPC Supplemental	3,882	90	950
5.	Interruptible Transportation, with Propane Air Supplemental	3,379	21	950
6.	Firm Transportation, Iroquois to NMPC, with NMPC Supplemental	3,859	214	0
7.	Firm Transportation, Iroquois to CNG to NMPC, with NMPC Supplemental	2,197	122	0
8.	Pipeline Connecting Iroquois to Fort Drum	-1,414	668	13,700
9.	DFSC, Firm Transportation, with NMPC Supplemental	2,856	160	0
10.	DFSC, Interruptible Transportation, with Propane Air Supplemental	6,905	236	950
11.	DFSC, Interruptible Transportation, with NMPC Supplemental	5,614	160	950

TABLE S.4. Analysis Results: Base Case-Entire Fort (1992 $ thousands)

	Strategy	NPV of Investment	Annual Energy Cost Savings	Initial Capital Cost
1.	Large Volume Interruptible Rate with Propane Air Supplemental	16,761	764	1,393
2.	Interruptible Transportation, Iroquois to NMPC, with Propane Air Supplemental	23,647	1,138	1,393
3.	Interruptible Transportation, Iroquois to CNG to NMPC, with Propane Air Supplemental	19,682	317	1,393
4.	Interruptible Transportation, with NMPC Supplemental	9,783	370	1,393
5.	Interruptible Transportation, with Propane Air Supplemental	5,030	-190	1,393
6.	Firm Transportation, Iroquois to NMPC, with NMPC Supplemental	11,746	650	0
7.	Firm Transportation, Iroquois to CNG to NMPC, with NMPC Supplemental	7,780	428	0
8.	Pipeline Connecting Iroquois to Fort Drum	17,582	1,730	13,700
9.	DFSC, Firm Transportation, with NMPC Supplemental	4,796	555	0
10.	DFSC, Interruptible Transportation, with Propane Air Supplemental	20,672	939	1,393
11.	DFSC, Interruptible Transportation, with NMPC Supplemental	21,397	1,025	1,393

TABLE S.5. Analysis Results: High Gas Price Forecast-Entire Fort (1992 $ thousands)

	Strategy	NPV of Investment	Annual Energy Cost Savings	Initial Capital Cost
1.	Large Volume Interruptible Rate with Propane Air Supplemental	20,020	764	1,393
2.	Interruptible Transportation, Iroquois to NMPC, with Propane Air Supplemental	28,298	1,138	1,393
3.	Interruptible Transportation, Iroquois to CNG to NMPC, with Propane Air Supplemental	23,617	917	1,393
4.	Interruptible Transportation, with NMPC Supplemental	11,842	370	1,393
5.	Interruptible Transportation, with Propane Air Supplemental	12,164	-190	1,393
6.	Firm Transportation, Iroquois to NMPC, with NMPC Supplemental	13,955	650	0
7.	Firm Transportation, Iroquois to CNG to NMPC, with NMPC Supplemental	9,274	428	0
8.	Pipeline Connecting Iroquois to Fort Drum	23,069	1,730	13,700
9.	DFSC, Firm Transportation, with NMPC Supplemental	11,453	552	0
10.	DFSC, Interruptible Transportation, with Propane Air Supplemental	25,489	939	1,393
11.	DFSC, Interruptible Transportation, with NMPC Supplemental	25,406	1022	1,393

TABLE S.6. Analysis Results: NMPC Interruption-Entire Fort (1992 $ thousands)

	Strategy	NPV of Investment	Annual Energy Cost Savings	Initial Capital Cost
1.	Large Volume Interruptible Rate with Propane Air Supplemental	15,747	684	1,393
2.	Interruptible Transportation, Iroquois to NMPC, with Propane Air Supplemental	23,647	1,138	1,393
3.	Interruptible Transportation, Iroquois to CNG to NMPC, with Propane Air Supplemental	19,682	917	1,393
4.	Interruptible Transportation, with NMPC Supplemental	9,268	319	1,393
5.	Interruptible Transportation, with Propane Air Supplemental	5,030	-190	1,393
6.	Firm Transportation, Iroquois to NMPC, with NMPC Supplemental	11,746	650	0
7.	Firm Transportation, Iroquois to CNG to NMPC, with NMPC Supplemental	7,780	428	0
8.	Pipeline Connecting Iroquois to Fort Drum	17,582	1,730	13,700
9.	DFSC, Firm Transportation, with NMPC Supplemental	4,796	555	0
10.	DFSC, Interruptible Transportation, with Propane Air Supplemental	21,043	924	1,393
11.	DFSC, Interruptible Transportation, with NMPC Supplemental	18,088	791	1,393

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FIGURES

TABLES

1.0 INTRODUCTION

This analysis investigates strategies for Fort Drum to acquire a reliable natural gas supply while reducing its gas supply costs. The purpose of this study is to recommend an optimal supply mix based on the life-cycle costs of each strategy analyzed. In particular, this study is intended to provide initial guidance as to whether or not the building and operating of a propane-air mixing station is a feasible alternative to the current gas acquisition strategy.

The analysis proceeded by defining the components of supply (gas purchase, gas transport, supplemental fuel supply); identifying alternative options for each supply component; constructing gas supply strategies from different combinations of the options available for each supply component (the strategies are explained in Section 3); and calculating the life-cycle costs of each supply strategy under a set of different scenarios reflecting the uncertainty of future events (the scenarios are defined in Section 4). This procedure is illustrated in a flowchart in Figure 1.1. The process by which natural gas is supplied to a major customer such as Fort Drum is rather complex, and a brief description of the gas supply process is warranted.

1.1 COMPONENTS OF SUPPLY

The supply process has been broken down into five components, as illustrated in Figure 1.1 and discussed in detail in Section 2. The first component is the purchase of gas at the "wellhead," where natural gas is first produced. The second component is the transportation of the gas by small feeder pipelines to a major inter-state pipeline. The third component is the transportation of the gas through the major pipeline to a distribution point close to its final destination: this distribution point is known as the "city-gate." The fourth component is the transportation of the gas from the city-gate to its final destination (the "burner-tip") by the local gas utility company. The fifth component is the acquisition of supplemental fuel, either natural gas from the local gas utility, or a second fuel such as propane or fuel oil. These supply components are more thoroughly explained in Section 2.

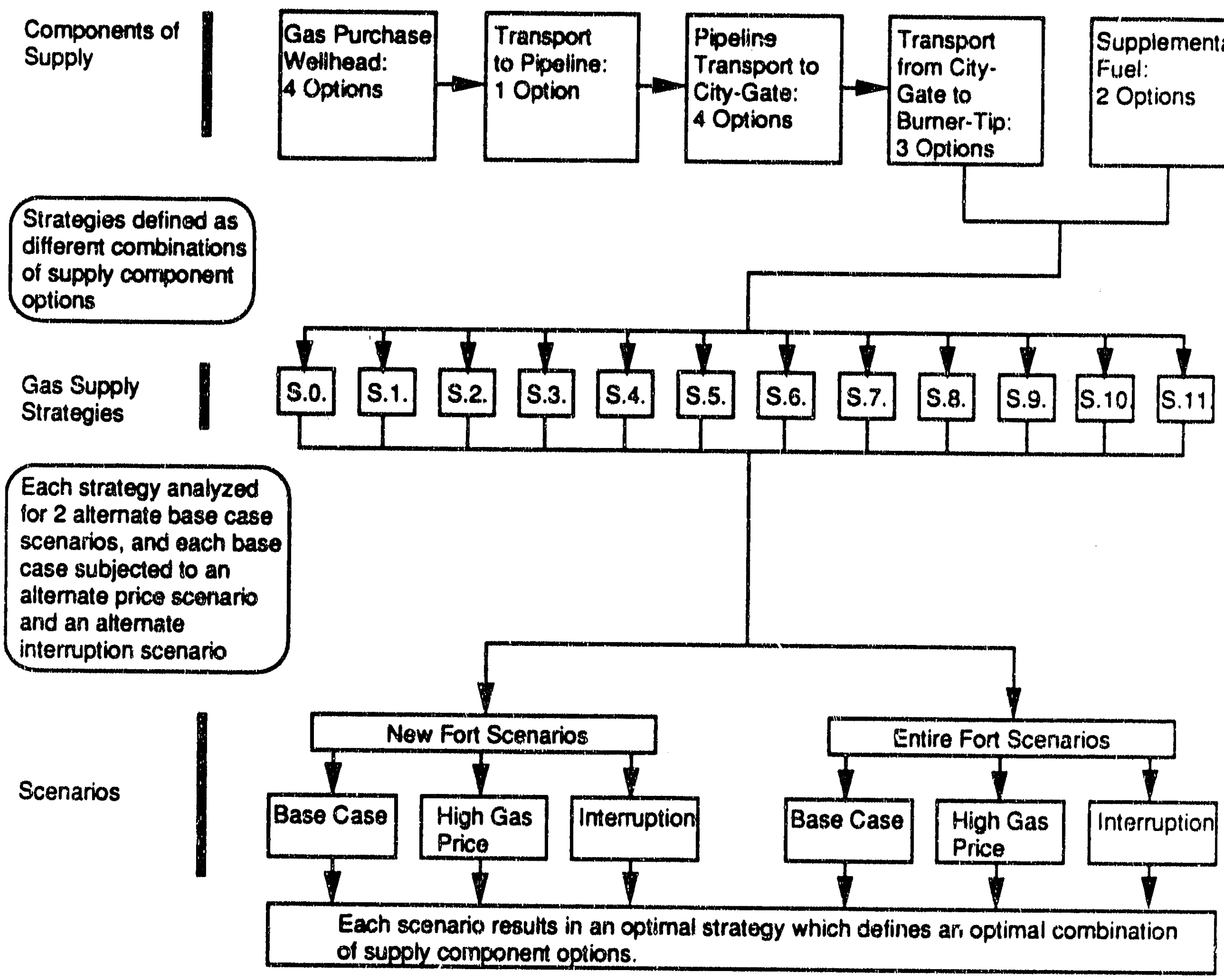

FIGURE 1.1. Flowchart of Analysis Process

At present, Fort Drum buys its gas at the wellhead through a natural gas broker (Hudson Bay). The broker arranges transportation to the Consolidated Natural Gas (CNG) pipeline, and charges Fort Drum for the cost of transportation to CNG. CNG moves the gas to NMPC (the city-gate), and charges Fort Drum for the cost of transportation to the city-gate. NMPC moves the gas to

Fort Drum and charges the Fort for transportation to the burner-tip. This arrangement has saved Fort Drum nearly 30% of the cost of purchasing gas directly from NMPC.[a]

1.2 FIRM VERSUS INTERRUPTIBLE

The purchase of natural gas and the transportation of gas can both be arranged under "firm" or "interruptible" contracts. A firm gas purchase contract means that the customer is guaranteed to receive all of the natural gas for which he or she has contracted, and a firm gas transportation contract means that the customer is guaranteed to receive all of the gas transportation capacity for which he or she has contracted. Interruptible contracts, on the other hand, allow the natural gas provider or the transportation provider to "interrupt" customers, providing them less gas or less transportation than the contracted amount. The gas or transportation provider would interrupt the customer in times of peak demand, such as extremely cold winter days, so that the needs of the firm customers could be met. Firm contracts carry a premium charge for the gas and transportation they provide, reflecting the guaranteed nature of the service. Appendix A contains the Niagara Mohawk Power Corporation's (NMPC) rate schedule for firm and interruptible gas purchase and transportation.

1.3 SPOT MARKET

Natural gas can be purchased through a natural gas utility company, such as NMPC, or it can be purchased through a broker on the open market. The "spot market" for natural gas refers to the process by which gas is sold at prevailing prices to the brokers, utilities, and major customers. Prices in the spot market fluctuate greatly, and a successful gas broker can use the spot market to cut gas costs considerably. Fort Drum currently contracts with a gas supply broker to purchase gas on the spot market.

(a) Memorandum for Doc, Attn: Gordon Reynolds, Engineering Housing & Support Center, Army Corps of Engineers. 14 June 1991. From Gordon E. Greene, Chief, Utilities - Electrical Branch, Engineering and Housing Directorate, Fort Drum.

1.4 ORGANIZATION OF THE REPORT

Section 2 of this report discusses the components of supply mentioned above, and Section 3 discusses how options available for each supply component were combined into strategies. Section 4 defines the scenarios used in the analysis. Section 5 describes the formulation of the gas consumption forecast. Section 6 describes how the costs of each strategy were developed. Section 7 presents results, and discusses some limitations of the analysis. Section 8 is the reference list. Four appendixes provide supplemental information.

2.0 COMPONENTS OF SUPPLY

The natural gas supply process was broken down into five components that describe the purchasing and transporting of natural gas and the provision of supplemental gas service in the event that an interruption occurs. The five components and the options available for each are listed in Table 2.1. At present, Fort Drum contracts with a gas supply broker who is purchasing U.S. Gulf Coast gas, transporting it from the wellhead to Niagara Mohawk Power Corporation via the CNG pipeline, and then transporting it through NMPC on its SC8 firm transportation rate, with supplemental gas provided by NMPC under its SC6 rate.

TABLE 2.1. Natural Gas Supply Components and Options

1. Gas Purchase at Wellhead

   Option 1: Purchase U.S. Gulf Coast gas
   Option 2: Purchase Canadian gas
   Option 3: Purchase gas through the DFSC
   Option 4: Purchase gas from NMPC under rate SC4

2. Transport to Pipeline

   Option 1: CNG feeder pipeline or Iroquois feeder pipeline

3. Pipeline Transport to City-Gate

   Option 1: CNG to NMPC
   Option 2: Iroquois to CNG to NMPC
   Option 3: Iroquois to NMPC
   Option 4: Iroquois to Fort Drum (bypasses city-gate)

4. Transport from City-Gate to Burner-Tip

   Option 1: NMPC firm transportation under rate SC8
   Option 2: NMPC interruptible transportation under rate SC5-I
   Option 3: Iroquois to Fort Drum (bypasses city-gate)

5. Supplemental Fuel Service

   Option 1: Dual-Fuel System
   Option 2: NMPC supplemental gas service under rate SC6

The first component is the actual purchase of natural gas at the wellhead. We looked at four options for gas purchase: U.S. Gulf Coast gas; Canadian gas; purchase through the Defense Fuel Supply Center (DFSC); and NMPC gas service under rate SC4, which involves NMPC handling the details of the wellhead purchase. Under the SC4 rate, NMPC would also handle all aspects of transporting the gas, bypassing the next three components.

The second component in gas supply is transporting gas from the wellhead to a major pipeline. We did not investigate options under this component, as this is usually handled by the broker who arranges the gas purchase.

The third component is the interstate transport of gas over the major pipeline to what is known as the "city-gate," which is the transfer point on the major pipeline closest to the point of final delivery. We looked at four options for interstate transport. The first option is the existing situation, where gas is transported from CNG's Ohio terminus to NMPC. The three alternative options all involved transportation of Canadian gas over the newly constructed Iroquois pipeline. At present, gas can be moved through the Iroquois pipeline to CNG, and then moved to NMPC. Alternatively, Iroquois will be completing a direct link to NMPC within 2 years. The final Iroquois option is to build a direct link between the Iroquois pipeline and Fort Drum, which bypasses the city-gate.

The fourth component in gas supply is the transportation of gas from the city-gate to its final destination, known as the "burner-tip." Three options were considered for this component. Gas could be moved by NMPC under the firm transportation rate SC8, which is the current situation. Alternatively, NMPC could transport the gas under the interruptible rate SC5-I. The third option is the direct pipeline link from Iroquois to Fort Drum, which avoids the city-gate entirely.

The fifth and final component in the gas supply process is the provision of supplemental gas service. Supplemental service is a requirement for taking service under an interruptible rate. Supplemental service can be provided through the construction of a dual-fuel system, such as a propane-air mixing station or an oil-fired system. NMPC can also provide supplemental service under the SC6 rate for customers who have chosen to transport their own gas at a firm rate. This analysis examined the propane and the NMPC options, but the analysis of an oil-fired, dual-fuel system is beyond the scope of this study. Such a system would require the installation of dual-fuel furnaces, boilers, and water heaters, for example.

The options available under the five supply components fall into four general categories: 1) alternative rate structures within NMPC, 2) dual-fuel capabilities, 3) alternative pipelines, and 4) alternative suppliers. These options are discussed in more detail below. Other options, such as using another utility company or an alternative broker, were dismissed. Rochester Gas and Electric, another utility company, was dismissed because utilities are not allowed to service customers outside of their district.[a] Alternative brokers may present a cost saving over the current broker, but the examination of this option was beyond the scope of this analysis.

2.1 EXISTING SUPPLY CONTRACT

Fort Drum currently contracts through Hudson Bay Natural Gas Corporation (Hudson Bay) for its gas supply, which is then delivered via the CNG pipeline through NMPC. The contract with Hudson Bay is a 1-year renewable contract. Gas pricing is indexed with the publication Natural Gas Week and is bought on the spot market according to each month's prices.[b] In addition to charging for the gas, Hudson Bay charges a fee for transportation to the NMPC pipeline, which varies from month to month, and an adjustment factor, which is a fixed charge per therm and which does not vary from month to month within the contract year. The last optional renewal period of the broker contract expires May 31, 1993.

Fort Drum's contract with NMPC is for firm transportation under its SC8 rate (transportation service with standby sales service), with supplemental gas service for gas transportation service customers at NMPC's SC6 rate. NMPC delivers Fort Drum-purchased gas to the Fort, charging it for transportation

(a) Personal Communication, Dave Gardner, Gas Purchasing and Transportation, Rochester Gas and Electric Co., February 25, 1992.
(b) Current gas purchasing contract with Hudson Bay Natural Gas Company for supply of natural gas to Fort Drum, Section B, item 0001A, p. B-1.

of gas and a demand charge. In addition, NMPC provides supplemental gas to meet the Fort's demand beyond the amount Hudson Bay is able to supply. Supplemental gas is supplied at the SC6 rate on an interruptible basis.

2.2 GAS PURCHASE AT WELLHEAD

There are three potential sources of natural gas for Fort Drum. They are: the purchase of U.S. Gulf Coast gas; the purchase of Canadian gas; and the purchase of natural gas through the local distribution company (LDC), NMPC. Fort Drum is not limited to buying natural gas from a broker or NMPC. CNG also acts as a supplier in addition to offering transportation services. With a broker, gas is often purchased on the spot market, ensuring the lowest price available at that time. In order to purchase gas from CNG, a customer must sign a 6-month or 1-year contract to purchase gas at a fixed price. Under a fixed contract, the customer would be protected against erratic prices and price increases, but if the price of gas were to fall, then the customer would pay more for that month compared with the price that would have been paid under a spot market or indexed contract price. However, this option was not explored because CNG is not interested in offering a gas package to Fort Drum at this time.[a]

2.2.1 Option 1: Purchase of U.S. Gulf Coast Gas

While it may be possible for Fort Drum to do all of the work involved in the procurement process, the common procedure is to contract this component to a brokerage firm that deals with the purchasing and transporting of natural gas. In this option, the primary supply source would be the U.S. Gulf Coast natural gas fields. The broker also arranges for the transport of the gas to the LDC.

2.2.2 Option 2: Purchase of Canadian Gas

As with the Gulf Coast gas purchase, the purchase of Canadian gas is contracted out to a brokerage firm which then purchases Canadian gas and arranges for transportation to the LDC.

(a) Correspondence, Bob Phillips, Manager, Interstate Marketing, Consolidated Natural Gas Transmission Corporation. March 3, 1992.

2.2.3 Option 3: Purchase Gas through the Defense Fuel Supply Center (DFSC)

Many Department of Defense installations are now required to purchase their natural gas through the DFSC, and Fort Drum may be required to do so as well. The DFSC currently contracts the procurement of natural gas to a broker who makes all arrangements for delivery to the city-gate. The installation must sign a contract with the LDC to transport gas from city-gate to burner-tip. In the future, the DFSC plans to arrange all procurement and transportation of natural gas.[a]

Natural gas purchased through the DFSC is transported on an interruptible basis to the city-gate. In order to provide reliable delivery, the contract between the DFSC and the transporter contains clauses that make provisions for possible short-falls during the winter. First, natural gas can be provided by Appalachian sources when Gulf Coast gas cannot get to the Northeast. Second, curtailments in transportation prior to the LDC are limited to a total of 21 days from November through March; and a continuous curtailment may only last 10 days.[a]

2.2.4 Option 4: Purchase Gas from NMPC under Rate SC4

Fort Drum can also choose to purchase natural gas directly from the LDC (NMPC). NMPC would then handle all purchasing and transporting of the gas. A copy of NMPC's rate schedule appears in Appendix A.

NMPC's SC4 rate (large-volume interruptible natural gas service) provides NMPC gas to customers who use at least 2.5 million therms per year and who have 100% dual-fuel capability. NMPC suggests that the dual-fuel system should be able to supply all energy needs for at least 1 week and that a complete switchover be possible within 4 hours.[b]

There are three potential dual-fuel systems: a compressed gas system, gas storage, and fuel oil. Fuel oil was dismissed as an option for this study because of the high costs associated with environmental compliance and the

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(a) Personal Communication, David Robinson, Alternate Fuels, Defense Fuel Supply Center. May 22, 1992. 12:45 pm.
(b) Personal Communication, Janice Bailey, Supervisor, Customer Transportation, Niagara Mohawk Power Corporation. February 21, 1992.

current activities at Fort Drum involving the conversion from fuel oil to natural gas on the Old Fort site. The other options are discussed in more detail later in this section.

At present, there is an \$825 minimum monthly charge for SC4 service, plus gas costs. However, NMPC is applying for approval for a decrease to \$250 per month. This change, if approved, would take effect in January 1993.[a]

2.3 TRANSPORT TO PIPELINE

This component was not explored, as the transportation is arranged by either the broker or NMPC.

2.4 PIPELINE TRANSPORT TO CITY-GATE

The third component of gas supply involves the transporting of gas from the feeder pipelines to the LDC. There are two pipelines through which gas could be delivered to NMPC: CNG and Iroquois.

2.4.1 Option 1: CNG to NMPC

The CNG pipeline is used primarily to deliver gas purchased from the Gulf Coast, although Canadian gas could be fed into the CNG pipeline from other pipelines. We assumed that CNG would only be carrying Gulf Coast natural gas.

2.4.2 Option 2: Iroquois to CNG to NMPC

At present, Fort Drum's gas is transported from the supply location through the CNG pipeline to Fort Drum via NMPC. Another pipeline, Iroquois, is also providing gas transportation in the area. Because Iroquois does not sell gas, a broker would be necessary, but this option would allow for an alternative transportation route. At this time, a direct link between Iroquois and NMPC does not exist, but it is possible for gas to be shipped from Iroquois to NMPC via the CNG pipeline, and then on to Fort Drum.

(a) Personal Communication, Janice Bailey, Supervisor, Customer Transportation, Niagara Mohawk Power Corporation. March 18, 1992. 10:30 a.m.

2.4.3 Option 3: Iroquois to NMPC

While direct transport from the Iroquois pipeline to NMPC is not presently available, a pipeline linking Iroquois to NMPC is planned for 1994, which would eliminate the need to transport through CNG. It must be pointed out, though, that Iroquois will not be adding customers until November 1993, so all strategies involving Iroquois transportation are not immediately implementable.[a]

2.4.4 Option 4: Iroquois to Fort Drum

Another potential supply option is for Fort Drum to build a pipeline extending from the Iroquois Gas Transmission (Iroquois) pipeline. This option would require approval from the Federal Energy Regulation Commission (FERC). Because the pipeline would enter NMPC's service district, NMPC would most likely be opposed to the project, causing extensive delays and litigation.

A pipeline would also require extensive investment expenditure. Iroquois estimates that to construct a pipeline covering the 27.4-mile distance from the Iroquois pipeline to Fort Drum's outlet would cost approximately $500,000 per mile, with annual operation and maintenance costs estimated at $13,700.[b]

2.5 TRANSPORT FROM CITY-GATE TO BURNER-TIP

Fort Drum lies within the boundary of NMPC's service district, and must therefore arrange its transportation from city-gate to burner-tip through NMPC. Niagara Mohawk provides gas transportation under different rate schedules. There are two primary types of rate schedules: those for firm gas supply and transportation, and those for interruptible supply and transportation. Both have advantages and disadvantages. Firm rates are higher because gas supply is guaranteed, while interruptible rates are lower because the supplier/transporter does not have to guarantee delivery. Under the

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(a) Personal communication, Chris Bosco, Iroquois Gas Transmission System. February 27, 1992.
(b) Personal Communication, Chris Bosco, Iroquois Gas Transmission System. March 4, 1992. 1:00 p.m.

interruptible rate, the customer could be interrupted or curtailed, at which time the gas company or pipeline requests the customer to halt gas usage or face large fines. Many interruptible rates require customers to have back-up or dual-fuel capabilities in case an interruption occurs.

The present rate, SC6, had been the best rate for which Fort Drum was eligible. With the estimated level of gas demand at Fort Drum, alternative rates have become feasible.

2.5.1 Option 1: NMPC Firm Transportation under Rate SC8

NMPC provides firm transportation of customer-owned natural gas to its customers under the SC8 rate (transportation service with standby sales service). Under this rate, the customer must be capable of consuming at least 1 million therms annually. The customer must also subscribe to the supplemental gas service under rate SC6.

2.5.2 Option 2: NMPC Interruptible Transportation under Rate SC5-I

Niagara Mohawk's SC5-I rate (large-volume interruptible gas transportation service) is available to those customers who qualify for the SC4 rate, but opt to purchase their gas from another supplier and then transport it to NMPC for distribution. These customers must take supplemental gas service from NMPC under the SC6 rate. This rate structure is similar to the SC8 rate under which Fort Drum currently operates in that it transports customer-owned gas with provisions for NMPC supplemental gas. Supplemental gas is provided when the customers' contracted supply is not enough to meet their demand for that month. As in the SC4 classification, the customer must have dual-fuel capability.

2.6 SUPPLEMENTAL FUEL SERVICE

The final component of gas supply is the provision of supplemental fuel in the event of an interruption. Supplemental fuel can be provided by a dual-fuel system built onsite or it can be purchased through NMPC.

2.6.1 Option 1: Dual-Fuel System

The three options for meeting the dual-fuel capability are: fuel oil, natural gas storage, and a compressed gas system. While recent prices have made fuel oil more attractive, a fuel oil system was dismissed due to the high costs associated with environmental compliance and the current activities at Fort Drum involving the conversion from fuel oil to natural gas on the Old Fort site.

Natural Gas Storage

The first option for dual-fuel capability is natural gas storage. This option involves buying extra gas during off-peak hours, such as summer months or night hours when demand for gas is low, and storing it until it is needed. There are three processes by which gas can be stored: low-pressure storage, high-pressure storage, and atmospheric-pressure storage of liquefied natural gas (LNG) in heat-insulated vessels. None of these options is feasible at Fort Drum, as described below.

Low-pressure storage facilities have generally been used in conjunction with gas production from coal or petroleum. The process involves expanding the gas before it enters the storage vessel and then sometimes recompressing it before distribution. The cost of these facilities is usually high in relation to their capacity, and the technology is more suited to coal and petroleum gasification, so this option was considered to be infeasible (Lom 1974, p. 16).

The second process involves storing natural gas at high pressure. High pressure gas storage vessels can be above or below ground. While there are some storage facilities aboveground, it is becoming more common to inject the natural gas into underground formations such as specially constructed caverns in salt rock or exhausted gas fields. It is assumed that Fort Drum does not have the suitable geology for underground salt caverns or exhausted gas fields in its vicinity, so this option was not explored (Lom 1974, p. 16). Gas storage along the pipeline itself would be a possibility; however, Iroquois[a]

(a) Personal Communication, Chris Bosco, Iroquois Gas Transmission System. February 27, 1992.

and NMPC[a] do not have gas storage capabilities, and CNG[b] does not offer gas storage to interruptible customers.

The third method of storage involves liquefying natural gas during the off-peak season and then revaporizing it during peak demand. The type of facility needed is known as a peakshaving plant. These plants operate in three stages: liquefaction, storage, and vaporization. Because of the cold temperature required for storage, LNG is considered to be cryogenic. New York State regulations prohibit storage of cryogenic materials, so this option was not explored.[c]

Mention has been made to the possibility of building a compressed natural gas station at Fort Drum, with NMPC underwriting some of the cost and using the facility to fill fleet vehicles.[d] While Utica, New York, has a natural gas station, it is only used for filling fleet vehicles, and there are no known stations in the area that use compressed natural gas for end uses other than vehicles. In discussing the use of compressed natural gas for heating, Richard Nikodem of the NMPC Utica office indicated that such a system makes sense only in remote areas where main line delivery is unreliable, and when the system is used for fleet vehicles.[e] Because Fort Drum has reliable delivery, and because vehicles are beyond the scope of this analysis, a compressed natural gas system was not explored further.

Compressed Gas System

Compressed gases refer primarily to liquefied petroleum gases (LPG). Propane and butane are the two primary types of LPG. Of the two gases, propane or a propane-butane mix are preferred because propane's boiling point is much lower than that of butane. Therefore, the more butane in the supply, the

(a) Personal Communication, Janice Bailey, Supervisor, Customer Transportation, Niagara Mohawk Power Corporation. February 21, 1992.
(b) Personal Communication, Bob Phillips, Manager, Interstate Marketing, Consolidated Natural Gas Transmission Corporation. February 27, 1992.
(c) Personal Communication, Ron Harvey, New York State Regulatory Affairs. February 25, 1992.
(d) Personal Communication, Jeff Marsh, Niagara Mohawk Power Corporation, Watertown Office. May 21, 1992. 1:45 pm.
(e) Personal Communication, Richard Nikodem, Niagara Mohawk Power Corporation, Utica Office. May 22, 1992. 8:30 am.

more energy that is required for vaporization. The gases can also be mixed with air. A propane-air mixture would be more desirable than other dual-fuel options because it shares many of the same characteristics as natural gas. For example, it requires the same types of equipment for burning as is necessary for the normal burning of natural gas, so the purchase of additional burning equipment is not necessary. Propane-air mixtures are also advantageous over straight LPG vapors because recondensation problems in distribution lines are decreased significantly. For these reasons, the only compressed gas system explored was that of a propane-air mixture.

2.6.2 Option 2: NMPC Supplemental Gas Service under Rate SC6

NMPC customers who transport their own gas are required to subscribe to NMPC's SC6 supplemental gas service in addition to the rate under which they are transporting gas. Natural gas under the SC6 rate is delivered on a best effort interruptible basis. SC6 gas is delivered when the customer's nominated amount of gas is not enough to meet the customer's needs. In comparison, a dual-fuel system is necessary when NMPC cannot meet the gas demand of the customer (an NMPC supply interruption). The dual-fuel system could also be used by the customer in place of the SC6 service at the customer's discretion.

3.0 GAS SUPPLY STRATEGIES

The supply components described in Section 2 were combined to describe the existing configuration (Strategy 0) and eleven alternative strategies, as represented in Table 3.1 and defined below:

Strategy 0: The base or existing strategy where gas is purchased through a broker, transported firm to city-gate via CNG, transported to burner-tip via NMPC under a firm transportation rate, with supplemental gas provided by NMPC.

Strategy 1: Purchasing gas from NMPC under an interruptible rate, with a propane-air station for supplemental gas service.

Strategy 2: Purchasing gas at the wellhead through a broker, transporting it firm to city-gate via Iroquois, transporting it to burner-tip from city-gate via NMPC under an interruptible transportation rate, with a propane-air station for supplemental gas service.

Strategy 3: Purchasing gas at the wellhead through a broker, transporting it firm to city-gate via Iroquois and CNG, transporting it to burner-tip via NMPC under an interruptible transportation rate, with a propane-air station for supplemental gas service.

Strategy 4: Purchasing gas at the wellhead through a broker, transporting it firm to city-gate via CNG, transporting it to burner-tip from city-gate via NMPC under an interruptible transportation rate, with supplemental gas service provided by NMPC. Requires a propane-air station for NMPC interruptible rate.

Strategy 5: Purchasing gas at the wellhead through a broker, transporting it firm to city-gate via CNG, transporting it to burner-tip via NMPC under an interruptible transportation rate, with a propane-air station for supplemental gas service.

Strategy 6: Purchasing gas at the wellhead through a broker, transporting it firm to city-gate via Iroquois, transporting it to burner-tip from city-gate via NMPC under a firm transportation rate, with supplemental gas service provided by NMPC.

Strategy 7: Purchasing gas at the wellhead through a broker, transporting it firm to city-gate via Iroquois and CNG, transporting it to burner-tip from city-gate via NMPC under a firm transportation rate, with supplemental gas service provided by NMPC.

Strategy 8: Purchasing gas at the wellhead through a broker, transporting it firm directly to burner-tip (Fort Drum) via Iroquois pipeline, with no supplemental gas service.

Strategy 9: Purchasing gas through the DFSC, transporting it interruptible to city-gate CNG, transporting it to burner-tip from city-gate via NMPC under a firm transportation rate, with supplemental gas service provided by NMPC.

Strategy 10: Purchasing gas through the DFSC, transporting it interruptible to city-gate CNG, transporting it to burner-tip from city-gate via NMPC under an interruptible transportation rate, with a propane-air station for supplemental gas service.

Strategy 11: Purchasing gas through the DFSC, transporting it interruptible to city-gate CNG, transporting it to burner-tip from city-gate via NMPC under an interruptible transportation rate, with supplemental gas service provided by NMPC. Requires a propane-air station for NMPC interruptible rate.

TABLE 3.1. Natural Gas Supply Strategies

Strategy	Gas Purchase	Transport to Pipeline	Transport to City-Gate	Transport to Burner-Tip	Provide Supplemental Fuel Service
0	Gulf Coast	CNG Feeder	CNG Ohio to NMPC	NMPC (SC8) Firm	NMPC (SC6) Interruptible
1	NMPC (SC4) Interruptible	N/A	N/A	N/A	Propane Air
2	Canadian Gas	Iroquois Feeder	Iroquois to NMPC	NMPC (SC5I) Interruptible	Propane Air
3	Canadian Gas	Iroquois Feeder	Iroquois to CNG to NMPC	NMPC (SC5I) Interruptible	Propane Air
4	Gulf Coast	CNG Feeder	CNG Ohio to NMPC	NMPC (SC5I) Interruptible	NMPC (SC6) Interruptible
5	Gulf Coast	CNG Feeder	CNG Ohio to NMPC	NMPC (SC5I) Interruptible	Propane Air
6	Canadian Gas	Iroquois Feeder	Iroquois to NMPC	NMPC (SC8) Firm	NMPC (SC6) Interruptible
7	Canadian Gas	Iroquois Feeder	Iroquois to CNG to NMPC	NMPC (SC8) Firm	NMPC (SC6) Interruptible
8	Canadian Gas	Iroquois Feeder	Iroquois to Fort Drum, bypassing city-gate		None
9	DFSC Gas	N/A	N/A	NMPC (SC8) Firm	NPMC (SC6) Interruptible
10	DFSC Gas	N/A	N/A	NMPC (SC5I) Interruptible	Propane Air
11	DFSC Gas	N/A	N/A	NMPC (SC5I) Interruptible	NMPC (SC6) Interruptible

These strategies represent the supply strategies that are currently available or will be in the near future. All would present a reliable supply of natural gas to the Fort under our assumptions. In the strategies where gas is shipped through NMPC on an interruptible rate, we assumed that natural gas would be shipped by a broker on a firm basis to the city-gate (NMPC) and that a propane-air station would be built, as is required in order to be eligible for the NMPC interruptible rates. In the strategies where gas is bought through the DFSC, the gas would be shipped on an interruptible basis, but with contract clauses limiting curtailments. In the event of an NMPC interruption, the Fort should be able to rely on the propane-air station for its fuel supply.

In all other strategies, natural gas is assumed to be shipped on a firm basis to Fort Drum. Firm rates are usually higher than interruptible rates because demand charges are applied to the transportation of gas. A demand charge is basically a reservation on a pipeline for a specified quantity of gas. As long as a pipeline is not running at full capacity, reserving space should not be a problem, and a reliable gas supply is assured in most cases.

4.0 ANALYSIS SCENARIOS

Each of the supply strategies was explored under six different scenarios, as represented in Table 4.1. The scenarios could be grouped into two classifications based on the two consumption forecasts. Fort Drum is divided into two sections, a "New Fort" and an "Old Fort." The New Fort area is currently being fueled by natural gas, and historical data from this area provided the basis for the "New Fort" consumption forecast. The "Old Fort" area currently relies on fuel oil, but may be converting to natural gas in the future. The natural gas consumption forecast for this area was derived from past fuel oil needs. When combined, the New Fort and Old Fort forecasts make up the Entire Fort forecast and analysis.

Because there are two general scenario classifications, there are two base cases. The first, "New Fort," assumes that the conversion of the Old Fort from fuel oil to natural gas does not occur. The second, "Entire Fort," assumes that the conversion takes place.

The next two scenarios assume that gas prices rise at a faster rate than is forecast by the U.S. Department of Energy. According to the Gas Research Institute's (GRI) 1991 price forecast, Gulf Coast gas prices will rise to $2.50/Decatherm (Dt) by 1995, and to $5.40/Dt by 2010, while the DOE escalation rates used forecast an average 1995 Gulf Coast price of $1.56/Dt and an average 2010 price of $2.30/Dt. Because of the discrepancy in rate estimations, the High Gas Price forecast assumed that gas prices would rise at

TABLE 4.1. Analysis Scenarios

Scenario	Demand Scenario	Price Scenario	Interruption Scenario
1	New Fort	Base	Base
2	New Fort	High Gas	Base
3	New Fort	Base	NMPC Interruption
4	Entire Fort	Base	Base
5	Entire Fort	High Gas	Base
6	Entire Fort	Base	NMPC Interruption

double the DOE escalation rate. When the DOE escalation rates are doubled, the estimated 1995 Gulf Coast price rises to $1.59/Dt, and to $3.06/Dt in 2010. This pricing scheme, while more moderate than the GRI, serves to illustrate the sensitivity of the results to a greater increase in gas prices. These higher gas prices were used under the New Fort and Entire Fort assumptions.

The final two scenarios assumed that there would be an interruption in the gas supplied by NMPC to the gas customers they serve under interruptible gas rates. The only component options that were affected by this assumption were gas purchase under the SC4 rate and supplemental fuel provision under NMPC's SC6 rate, because they represent the only times in which Fort Drum would be purchasing gas directly from NMPC. The interruption scenario assumptions are explained below in more detail.

According to historical data, Fort Drum's gas supply has been interrupted during the months of October through January. These interruptions were due to gas transportation exceeding capacity at the point at which gas enters the interstate pipeline in Ohio.[a] The broker (Hudson Bay) has therefore been unable to receive enough space on the interstate pipeline (CNG) to deliver the requested amount of natural gas. Once the gas is on the CNG pipeline, however, delivery to NMPC has not been, and is not expected to be, a problem since CNG has 17 connection points with the NMPC pipeline.[a] In the cases where the broker could not deliver the required supply, the excess requirement was purchased from NMPC under its Supplemental Gas Tariff (SC6). It may be possible to alleviate such supply interruptions by entering the CNG pipeline system through Buffalo, New York, or by moving gas via the newly built Iroquois pipeline.[a] The Buffalo connection was not examined further.

In estimating future pipeline capacities, it was assumed that during peak winter months, full gas supply from the broker would not be possible due to current pipeline capacity constraints. This results from the fact that the CNG pipeline, at the Ohio supply point, is currently running under full

(a) Personal Communication, Bob Phillips, Manager, Interstate Marketing, Consolidated Natural Gas Transmission Corporation. March 18, 1991. 11:30 a.m.

capacity, which could be considered a transportation bottleneck on the part of CNG. Because of this bottleneck, the amount of gas available from the Gulf Coast for the months of October through January was assumed to be the same as it was for FY 1991. Under the Entire Fort scenario, supply requirements will be much greater with the addition of the Old Fort; therefore, it was assumed that Fort Drum will exceed pipeline capacity at the CNG-Ohio point for the additional months of February through April. In February 1991, the gas supplied by the broker exceeded that of any other month for the period in which we have data. Therefore, the quantity supplied in that month was used to represent the maximum possible supply. All additional gas requirements during these 7 months will need to be met by supplemental sources.

One source is through the current local distribution company, NMPC. In the past, it has not been necessary for NMPC to interrupt its gas customers,[a] although interruptions of unknown duration may occur in the future as more customers come on line. Most interruptions would be caused by extreme weather conditions or pressure problems. NMPC currently has ongoing projects designed to increase pipeline capacity, including the construction of a pipeline connecting the Iroquois pipeline directly with an NMPC pipeline, scheduled for 1994.[b]

Because NMPC has been able to meet its customer's needs in the past, two scenarios for each supply mix regarding NMPC-supplied gas were explored. The first assumed that NMPC could meet any excess demand requirements, while the second allowed for interruption during the peak winter months, October through January. A total of six interruptions of varying durations were simulated for the Interruption scenario. The first interruption is assumed to last 24 hours and occurs in October. The second occurs in November and lasts 48 hours. Two interruptions were forecast for December for a total of 72 hours, and two

(a) Personal Communication, Dennis Bartlett, Gas Transportation Specialist, Niagara Mohawk Power Corporation. March 4, 1992. 9:00 a.m.
(b) Personal Communication, Gary Beland, Gas Supply and Planning, Niagara Mohawk Power Corporation. March 18, 1991. 11:00 a.m.

interruptions totaling 120 hours were scheduled for January. During the NMPC gas interruptions, the Fort would rely on the propane-air stations for its fuel requirements.

5.0 CONSUMPTION FORECAST

A 5-year monthly forecast of gas consumption at Fort Drum was developed to evaluate the supply strategies. The forecast of gas demand was done separately for the New Fort and for the Old Fort, and was then combined for an Entire Fort forecast. The New Fort has a history of natural gas consumption, which was combined with historical weather data to produce a weather-normalized forecast of natural gas use on the New Fort. This analysis includes gas consumption by New Fort commercial buildings and on-post housing; off-post housing was excluded from the analysis as it is served under different service contracts. The Old Fort monthly forecast was developed from a Fort Drum Directorate, Engineering and Housing (DEH) annual forecast, and includes two planned new facilities: the new airfield and the new vehicle wash facility.

Gas consumption on the New Fort is determined by the level of activity on the New Fort and by climate. The level of activity determines the base load, and the climate determines the heating load. Figure 5.1 plots gas consumption and climate data for fiscal year (FY) 1988 through FY 1991. Climate data are included in the form of heating degree days (HDD). Heating degree days are calculated by taking the average of the maximum and minimum temperatures for the day, and then comparing that average temperature with a base temperature, in this case 65°F.

A complete model of gas use should include a variable such as monthly manpower levels at the Fort as an indicator of activity. However, we were unable to obtain data on manpower levels due to security concerns. An examination of the data shows three distinct levels of gas use. There is a marked increase in consumption from FY 1988 to FY 1989, and then again from FY 1989 to FY 1990. We hypothesize that this pattern is a result of the increase in the level of activity at the New Fort from FY 1988 to FY 1990. We then compensate for the lack of actual activity data by including three activity indicator variables in the model. The first activity indicator is the "LOW" variable, which has a value of 1 in FY 1988 and 0 throughout the rest of the period. The second activity indicator is the "MEDIUM" variable, which has a

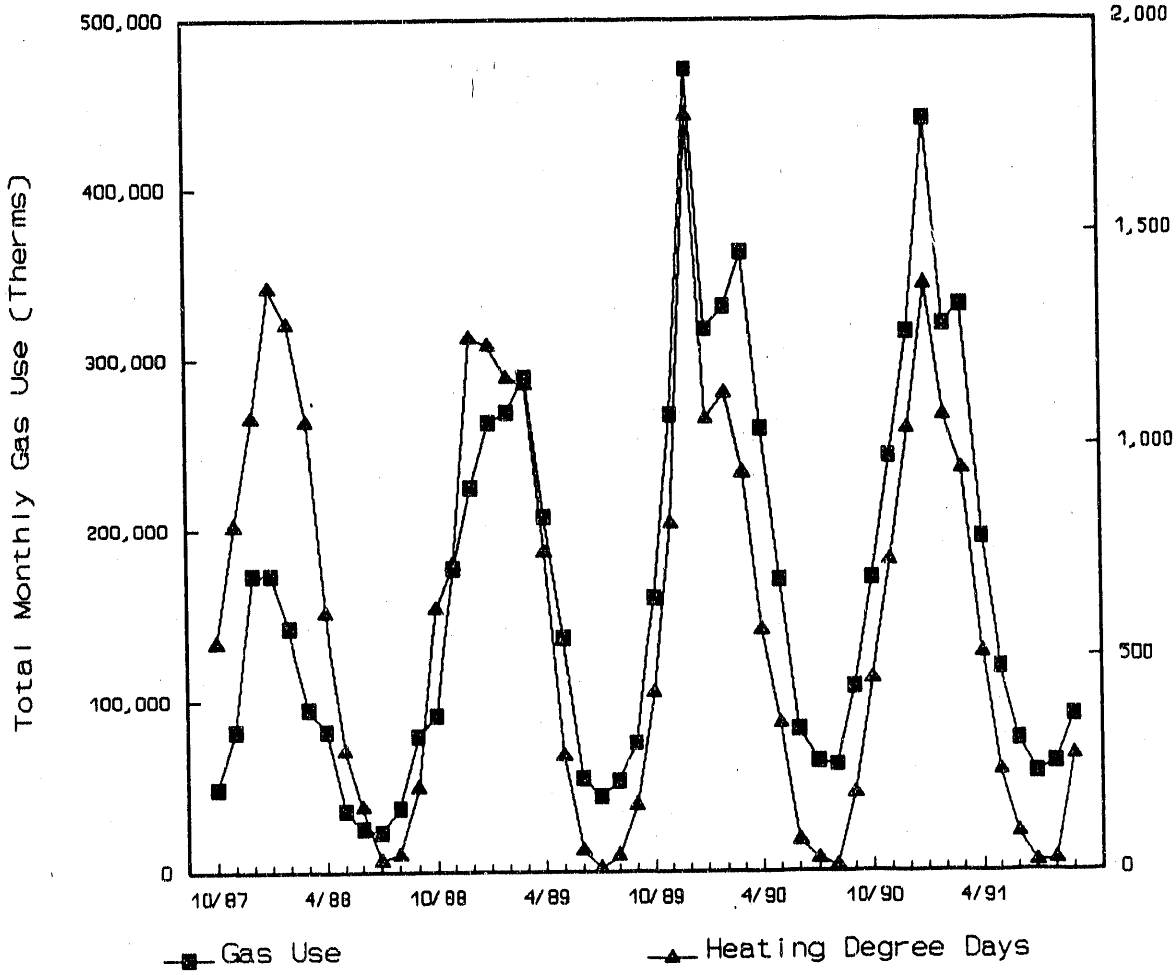

FIGURE 5.1. Gas Use and Heating Degree Days

value of 1 in FY 1989 and 0 throughout the rest of the period. The third activity indicator is the "HIGH" variable, which has a value of 1 in FY 1990 and FY 1991 and 0 throughout the rest of the period.

Natural gas consumption at the New Fort increased during 3 of the 4 years for which we have data. Natural gas consumption increased from FY 1988 to FY 1989 and again in FY 1990. Consumption remained at nearly the FY 1990 level in FY 1991. This analysis assumes that the increases in natural gas consumption were a result of increasing levels of activity as the New Fort was completed, and that this increasing trend ended. The analysis therefore assumes that future New Fort gas consumption will remain at approximately its FY 1991 level, after adjusting for weather effects. One factor complicating this forecast is the on-going Federal Energy Decision Screening (FEDS) Base Modernization activity being carried out by PNL. This activity should result in significant increases in natural gas efficiency. This analysis does not attempt to forecast these efficiency increases. Once the FEDS activity is completed and the natural gas efficiency improvements have been realized, the consumption forecast produced by this analysis should be adjusted.

The climate data and the activity indicators were combined in the following equation which was then estimated using the ordinary least squares (OLS) technique:

$$\begin{aligned} \mathrm{THERMS} = \beta_0 + \beta_1\mathrm{MEDIUM} + \beta_2\mathrm{HIGH} + \beta_3(\mathrm{LOW} * \mathrm{HDD}) \\ + \beta_4(\mathrm{MEDIUM} * \mathrm{HDD}) + \beta_5(\mathrm{HIGH} * \mathrm{HDD}) \end{aligned} \tag{5.1}$$

where THERMS = total monthly gas consumption, in therms

LOW = low activity indicator variable

MEDIUM = medium activity indicator variable

HIGH = high activity indicator variable

HDD = monthly total heating degree days.

Table 5.1 presents the results of the OLS estimation.

The high R-squared and high t-statistics indicate the model is a good fit. This is confirmed by Figure 5.2, which plots the actual gas use over the period against the predicted use for the time period October 1988 to September 1991. The inconclusive Durbin-Watson statistic does not allow us to reject the hypothesis of autocorrelation in the error terms, which if present could lead to misleading values for the t-statistics.

The regression model is used to forecast weather-normalized gas consumption. It is assumed that the current high level of activity at the New Fort will continue, and so the variables "LOW" and "MEDIUM" are set to zero, while the variable "HIGH" is set to 1. We then use the average monthly heating degree days at Fort Drum over the 10-year period 1976 to 1985 as our forecast

TABLE 5.1. OLS Estimation Results

Variable	Coefficient	Standard Error of Coefficient	T Statistic
Constant	21,430	26,889	0.80
M	28,201	18,004	1.57
H	41,344	15,457	2.67
L*HDD	100	17	6.02
M*HDD	175	16	10.77
H*HDD	255	11	22.38

R Squared = 0.95
Number of Observations = 48
Durbin-Watson D = 1.596

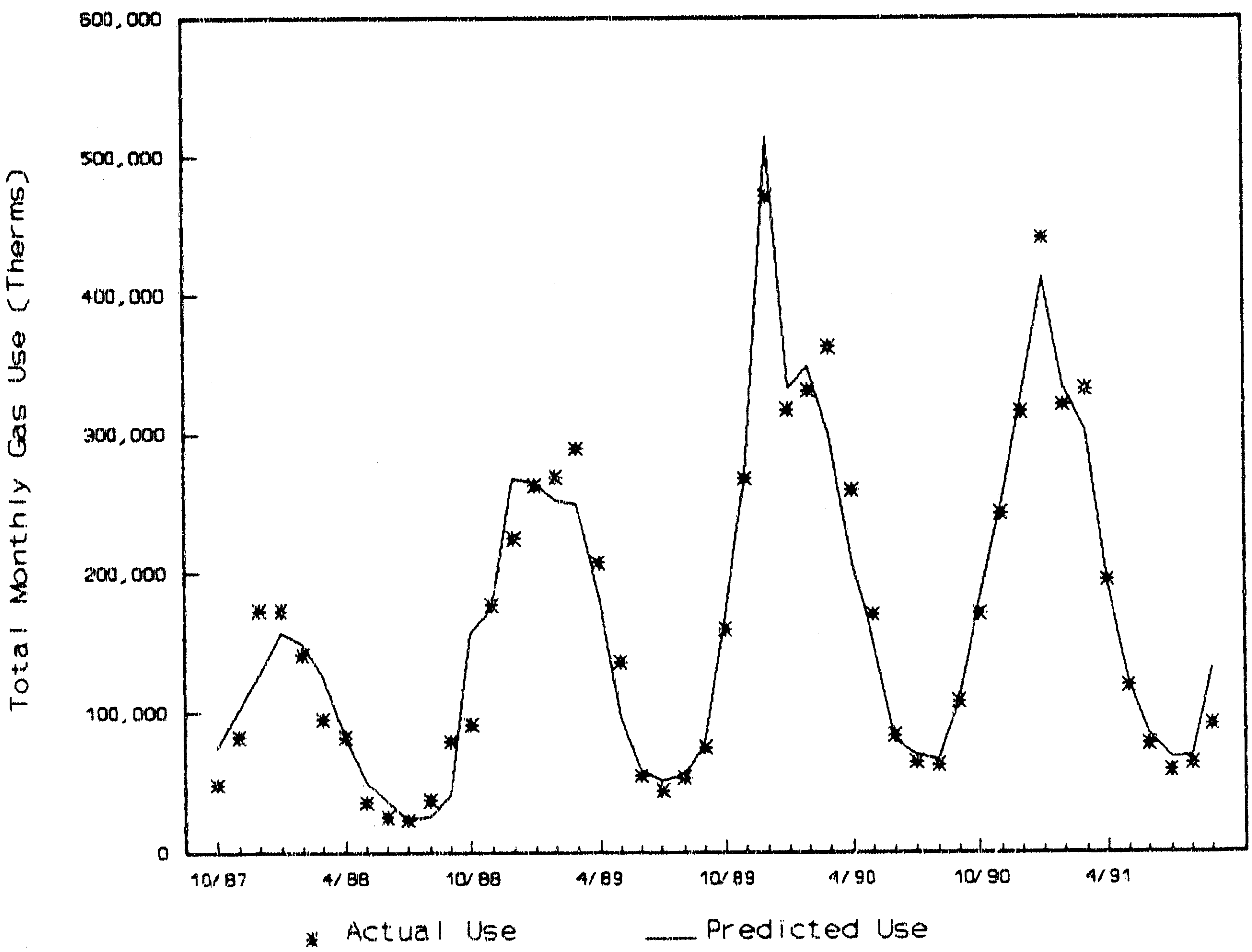

FIGURE 5.2. Actual Gas Use Versus Predicted Gas Use

of climate. Figure 5.3 plots the 10-year average HDD data against the 4 years of data in the model. The weather-normalized forecast of gas consumption is obtained when the estimated coefficients are used in the equation, with the activity indicator variables set as specified, and the average HDD data used for each month. Figure 5.4 shows 1 year of the New Fort forecast in relation to the 4 years of historical consumption data.

The Old Fort forecast is obtained by distributing the Fort Drum DEH annual Old Fort forecast (developed in support of the planned Old Fort conversion to natural gas) over the months of the year. This is done by using the average monthly share of total gas consumption developed from the historical data. The average shares are shown in Figure 5.5. The Old Fort monthly

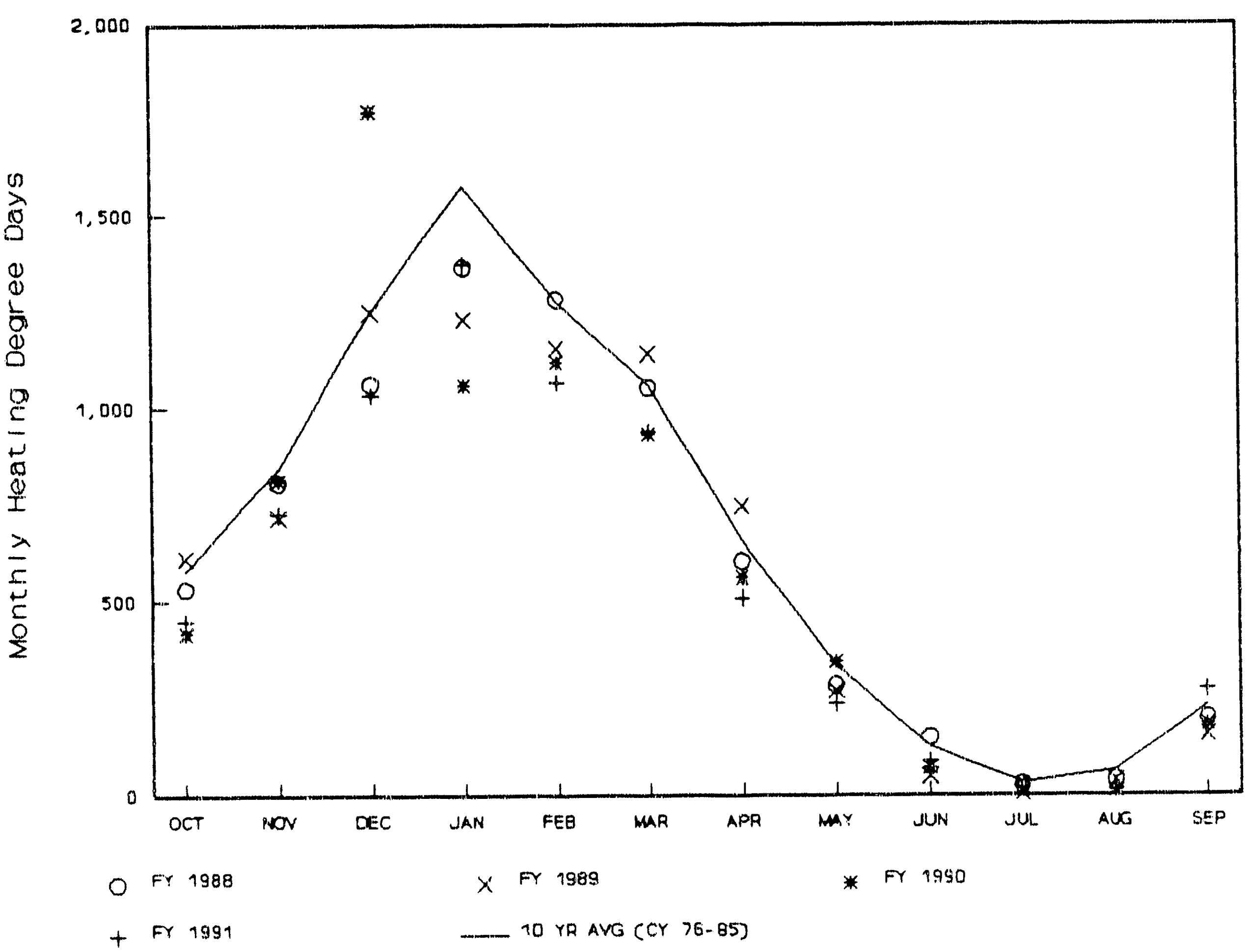

FIGURE 5.3. Heating Degree Days: FY 1988-91 and 10-Year Average

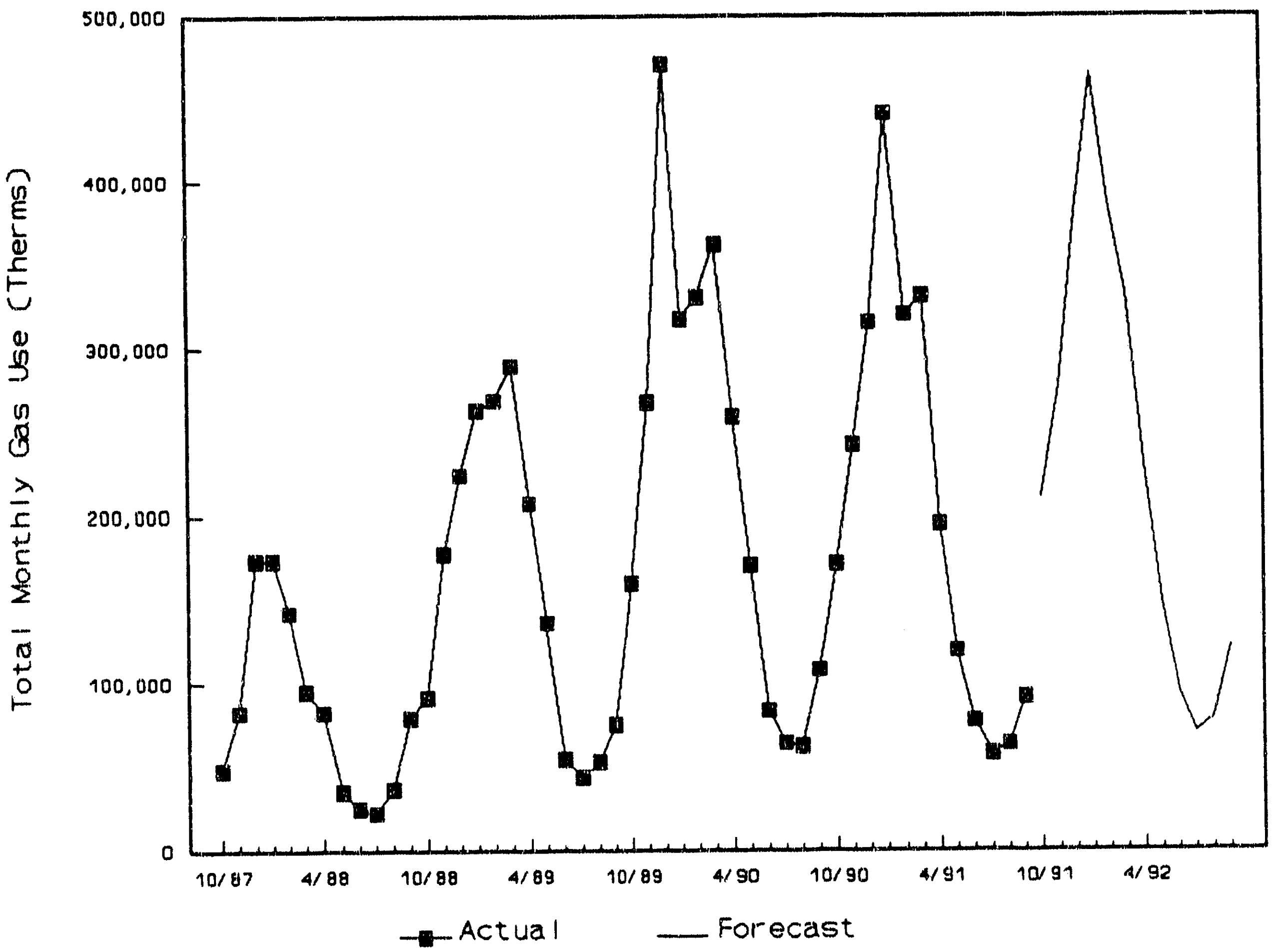

FIGURE 5.4. One-Year Forecast of Gas Use at New Fort

forecast is combined with the New Fort monthly forecast to produce the Entire Fort monthly forecast. This is presented for the entire 5-year forecast period in Figure 5.6.

Table 5.2 and Figure 5.7 present the total annual gas forecasts for the New Fort, the Old Fort, and the Entire Fort.

The forecasts used for this analysis assume that the activity level at Fort Drum will remain high. The analysis does not account for a decrease in activity level. If the Fort were to see a decrease in personnel, the results could be different.

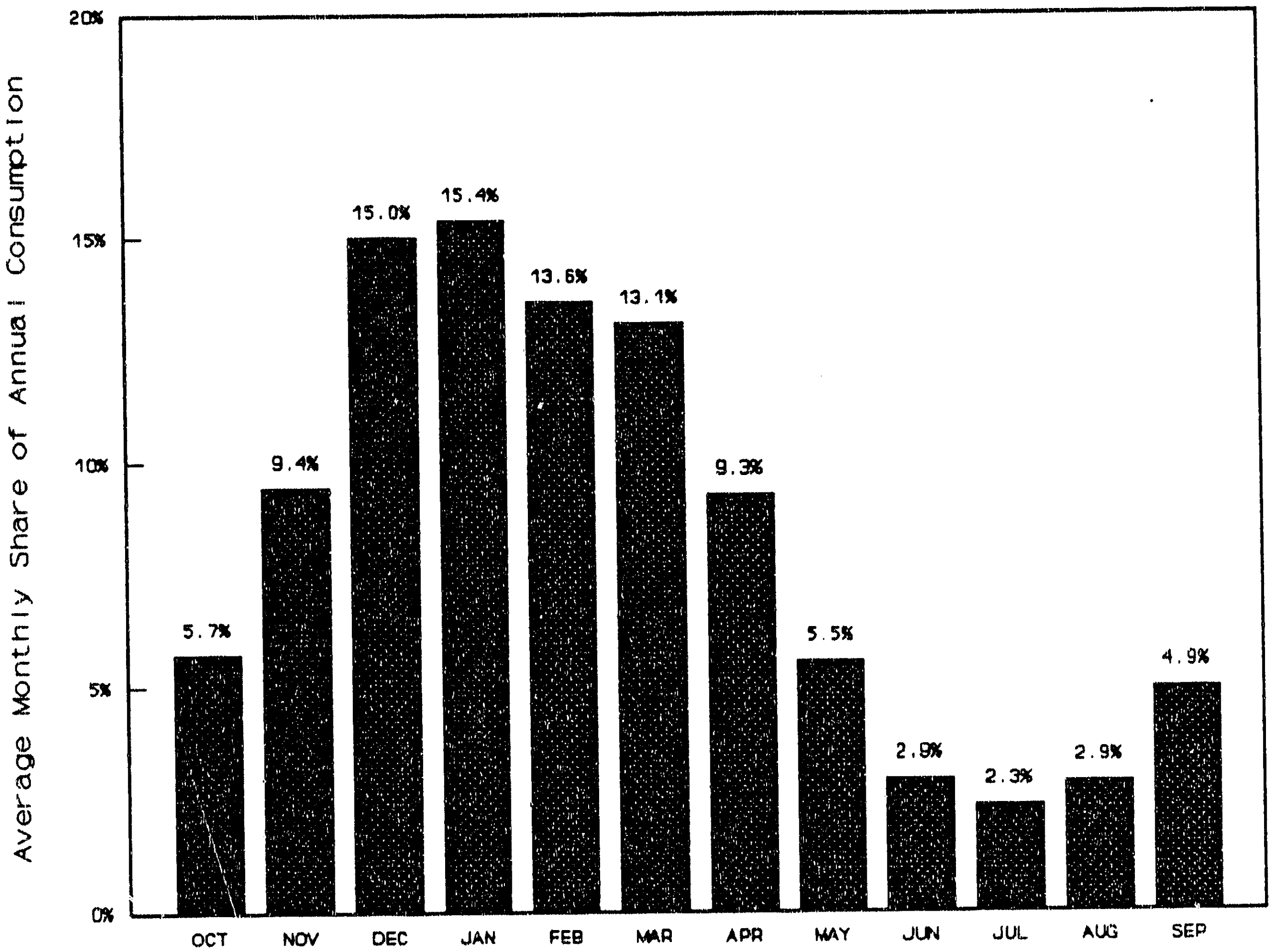

FIGURE 5.5. Monthly Share of Annual Consumption: Four-Year Average

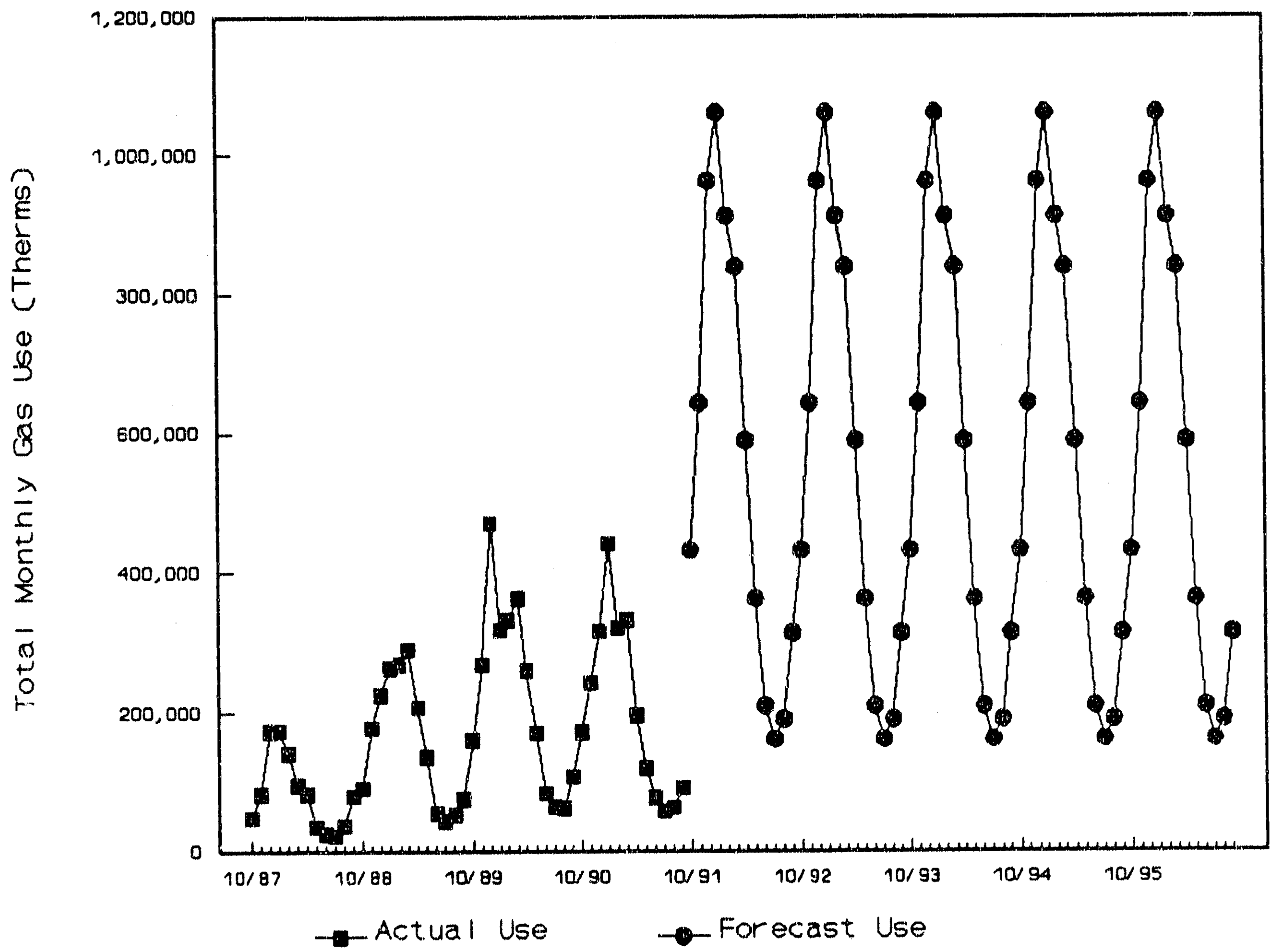

FIGURE 5.6. Five-Year Forecast of Gas Use - Entire Fort

TABLE 5.2. Annual Total Gas Use - Entire Fort (all values in therms)

Fiscal Year	Actual Use	New Fort Forecast	Old Fort Forecast	Total
1989	1,883,360			1,883,360
1990	2,653,203			2,653,203
1991	2,424,452			2,424,452
1992		2,795,656	3,873,750	6,669,406
1993		2,795,656	3,873,750	6,669,406
1994		2,795,656	3,873,750	6,669,406
1995		2,795,656	3,873,750	6,669,406
1996		2,795,656	3,873,750	6,669,406

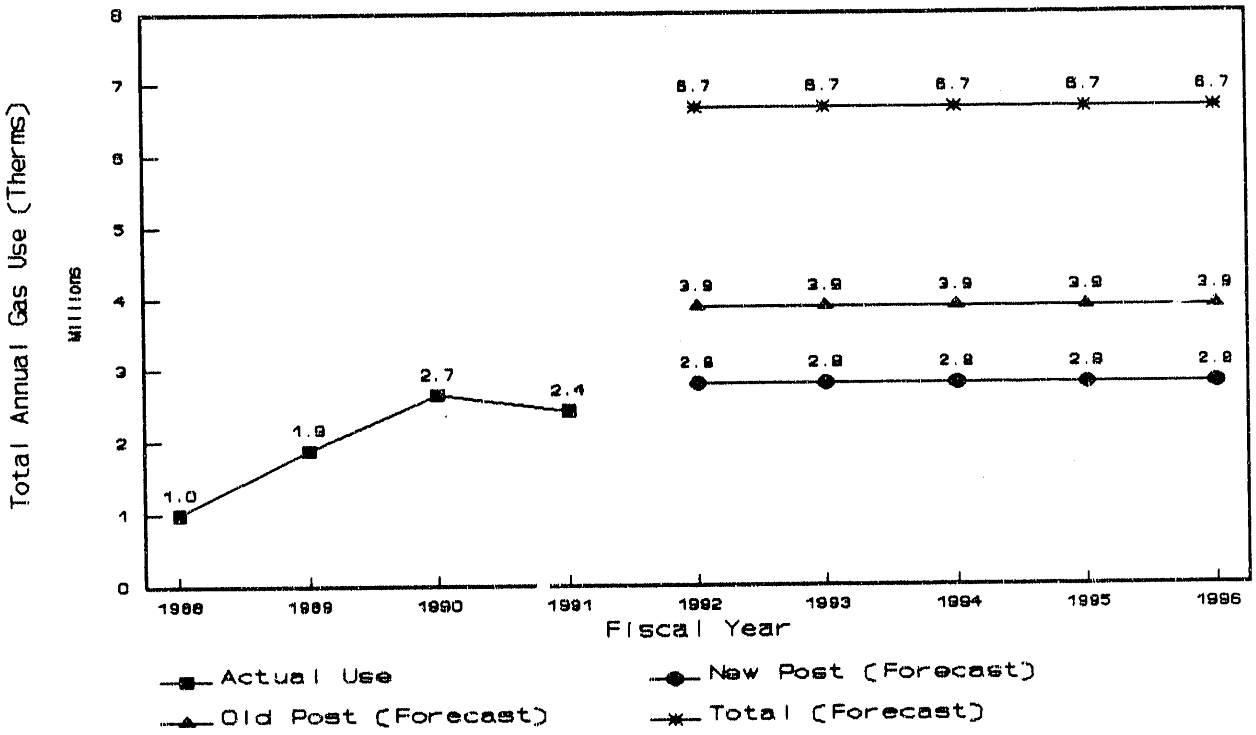

FIGURE 5.7. Five-Year Forecast of Gas Use - Annual Totals - Entire Fort

6.0 STRATEGY COST ESTIMATES

The estimation of strategy costs required energy cost forecasts and an estimation of the capital cost for a propane-air station. Energy costs include prices for natural gas, propane, electricity, and transportation rates. These costs are explained below.

6.1 FUEL PRICE ESTIMATES

In order to determine fuel costs for each of the supply mixes, fuel prices were escalated according to the DOE escalation rates. It was assumed that the DOE escalation rates included transportation, so they were also used for the escalation of transportation rates. The estimated initial annual average fuel prices are detailed in Table 6.1, and the initial summer and winter averages are given in Tables 6.2 and 6.3, respectively. Each of the price components is more thoroughly described below. The complete price and escalation rate tables are provided in Appendix B.

6.1.1 Natural Gas Price

In order to better represent the energy prices faced in each supply component, a series of natural gas prices were forecast for the analysis period.

TABLE 6.1. Initial Average Delivered Rates per Therm

Source	Commodity ($)	Percent (%)	Transport ($)	Percent (%)	Total ($)
Wellhead → CNG → NMPC (SC8)	0.1615	39	0.2567	61	0.4182
Wellhead → CNG → NMPC (SC5-I)	0.1615	53	0.1433	47	0.3048
Wellhead → IR → CNG → NMPC (SC8)	0.1337	33	0.2718	67	0.4055
Wellhead → IR → CNG → NMPC (SC5-I)	0.1337	46	0.1584	54	0.2921
Wellhead → IR → NMPC (SC8)	0.1337	36	0.2386	64	0.3723
Wellhead → IR → NMPC (SC5-I)	0.1337	52	0.1252	48	0.2589
NMPC (SC4)	0.2793	88	0.0388	12	0.3181
NMPC (SC6)	0.3891	84	0.0728	16	0.4619
Propane-Air	0.6004	100	0.0000	0	0.6004
Wellhead → IR → Fort Drum	0.1337	61	0.0864	39	0.2201
DFSC → NMPC (SC8)	0.2240	58	0.1601	42	0.3841
DFSC → NMPC (SC5-I)	0.2240	83	0.0467	17	0.2708

TABLE 6.2. Initial Summer Delivered Rates per Therm

Source	Commodity ($)	Percent (%)	Transport ($)	Percent (%)	Total ($)
Wellhead → CNG → NMPC (SC8)	0.1340	35	0.2459	65	0.3799
Wellhead → CNG → NMPC (SC5-I)	0.1340	50	0.1325	50	0.2665
Wellhead → IR → CNG → NMPC (SC8)	0.1337	33	0.2718	67	0.4055
Wellhead → IR → CNG → NMPC (SC5-I)	0.1337	46	0.1584	54	0.2921
Wellhead → IR → NMPC (SC8)	0.1337	36	0.2386	64	0.3723
Wellhead → IR → NMPC (SC5-I)	0.1337	52	0.1252	48	0.2589
NMPC (SC4)	0.2310	86	0.0388	14	0.2698
NMPC (SC6)	0.3891	84	0.0728	16	0.4619
Propane-Air	0.6004	100	0.0000	0	0.6004
Wellhead → IR → Fort Drum	0.1337	61	0.0864	39	0.2201
DFSC → NMPC (SC8)	0.2154	57	0.1601	43	0.3755
DFSC → NMPC (SC5-I)	0.2154	82	0.0467	18	0.2622

TABLE 6.3. Initial Winter Delivered Rates per Therm

Source	Commodity ($)	Percent (%)	Transport ($)	Percent (%)	Total ($)
Wellhead → CNG → NMPC (SC8)	0.1800	41	0.2640	59	0.4440
Wellhead → CNG → NMPC (SC5-I)	0.1800	54	0.1506	46	0.3306
Wellhead → IR → CNG → NMPC (SC8)	0.1337	33	0.2718	67	0.4055
Wellhead → IR → CNG → NMPC (SC5-I)	0.1337	46	0.1584	54	0.2921
Wellhead → IR → NMPC (SC8)	0.1337	36	0.2386	64	0.3723
Wellhead → IR → NMPC (SC5-I)	0.1337	52	0.1252	48	0.2589
NMPC (SC4)	0.3120	89	0.0388	11	0.3508
NMPC (SC6)	0.3891	84	0.0728	16	0.4619
Propane-Air	0.6004	100	0.0000	0	0.6004
Wellhead → IR → Fort Drum	0.1337	61	0.0864	39	0.2201
DFSC → NMPC (SC8)	0.2293	59	0.1601	41	0.3894
DFSC → NMPC (SC5-I)	0.2293	83	0.0467	17	0.2761

Separate pricing methodologies were used for wellhead (Gulf Coast), city-gate, DFSC, supplemental, and Canadian (wellhead) gas. These methodologies were derived as explained below.

The base price for Gulf Coast natural gas was the average price paid in FY 1991. The FY 1991 prices were calculated by dividing the amount paid for natural gas in the broker contract by the number of therms ordered. The average 1991 price was then forecasted out for a 25-year period using the DOE price escalations on commercial natural gas rates to determine yearly averages. Price escalations are given in Appendix B. These price averages were adjusted to allow for seasonal variation in prices within the year.

From the historical data collected, it was observed that during the winter months (November-March), the average gas price was 35% greater than the average gas price for the summer months (April-October). This provided the basis for the seasonal change adjustment. The forecast prices, assumed to be yearly averages, were used in conjunction with the percent difference to calculate summer and winter gas prices.

The base price for city-gate natural gas was the February 1992 city-gate price given by J. A. Kraker of Direct Gas.[a] This price was used as an annual average from which winter and summer averages for SC4 gas were calculated in the same manner as the Gulf Coast prices. These prices were then forecasted out for the 25-year period using the DOE escalation rates for commercial natural gas.

The base price used for DFSC natural gas was derived from 1991 data on city-gate prices for another DFSC New York Customer.[b] The data were divided into a winter average and a summer average, and include the cost of transportation to the city-gate. These rates were escalated according to the DOE escalation rates.

The base price used for SC6 supplemental gas was the tiered rate schedule from NMPC dated October 1991, minus the estimated transportation price, which was assumed to be equivalent to the SC8 transportation rate.

The base price for Canadian gas was derived by adding the Canadian wellhead price[c] to the Canadian Eastern Toll Transportation rate for

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(a) Personal Communication, J. A. (Sandy) Kraker, Direct Gas, February 26, 1992.
(b) Personal Communication, David Robertson, Alternate Fuels, Defense Fuel Supply Center. May 22, 1992. 12:45 p.m.
(c) Personal Communication, Mike Wedel, Manager, Marketing, BP Canada. April 1, 1992. 2:00 p.m.

transportation on the Trans Canada Pipeline to the Iroquois Pipeline.[a] This price was then converted from Canadian to U.S. dollars using the exchange rate of U.S. $0.829 to Canadian $1.00 given by Sea-First National Bank for April 1, 1992.[b] No information was available regarding possible seasonal variation in Canadian gas prices, so it was assumed that the average annual price does not vary seasonally. This annual average price was forecasted over the 25-year period using the DOE escalation rates for commercial natural gas since no information was available regarding Canadian escalation rates.

6.1.2 Propane Price

The base price for propane was calculated using an average of 3 months data from Fort Drum.[c] This price was forecasted over the analysis period using the DOE escalation rates for residential LPG. This price was assumed to be a yearly average which did not vary seasonally.

6.1.3 Electricity Price

Electricity is required to run the propane-air station compressors, vaporizers, and mixers; and is also necessary for lighting and heating the building in which the compressors would be housed. Estimates of the electricity required were provided by Combustion Services.[d]

A weighted average of the on-peak and off-peak prices was used as a base price for electricity per kilowatt hour, while the base demand charge used was the on-peak charge. Both the electricity price per kilowatt hour and the demand charge were then forecast for the 25-year period using the DOE escalation rates for commercial electricity (U.S. DOC 1991, p. 39). These prices were assumed to be yearly averages.

(a) Personal Communication, Mike Durnin, Engineering and Operations, Trans Canada Pipeline. April 1, 1992. 1:30 p.m.
(b) Personal Communication, Sea-First National Bank. April 1, 1992.
(c) Personal Communication, Steve Rowley, Fort Drum. February 10, 1992.
(d) Personal Communication, Ray Self, Combustion Services Inc. May 29, 1992. 8:00 a.m.

6.1.4 Transportation Price

For the analysis, it was assumed that the DOE escalation rates for natural gas included any real price escalation in transportation costs. Transportation prices were therefore assumed to rise at the same rate as natural gas. Broker transported gas also contains seasonal variation because of the larger volumes transported during the winter, making it more expensive to transport natural gas through pipelines. The most direct route may not be available, so alternative routes are often used.[a]

In addition to being adjusted by the DOE growth rate, the broker transportation rate was also adjusted for seasonal variation. According to historical data, there was a 21% difference between winter and summer transportation charges. The forecasted transportation rates were used as annual averages and were adjusted to allow for seasonal variation.

DFSC transportation rates were not broken out of the city-gate gas price, and no assumptions were made regarding transportation costs as no information was gathered on interruptible transportation prior to the NMPC pipeline.

Because NMPC SC4 and SC6 rates are not broken down into gas price and transportation price, the SC4 transportation cost was assumed to be equivalent to the SC5-I transportation. When the city-gate gas price was added to the SC5-I transportation rate, the total was within the range of recent SC4 rates, so it was assumed that the method gave a relatively close approximation. The SC6 transportation rate was assumed to be equivalent to the SC8 rate for transportation, which was subtracted from the rate for each tier to determine the SC6 gas price.

6.1.5 Delivered Fuel Price

The prices listed above were combined with the appropriate demand charges and taxes to create total delivered fuel prices. Figures 6.1 and 6.2 graph the rates over the 25-year period for strategies 1, 2, and 11, and the

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(a) Personal Communication, J. A. (Sandy) Kraker, Direct Gas Natural Gas Company. February 26, 1992.

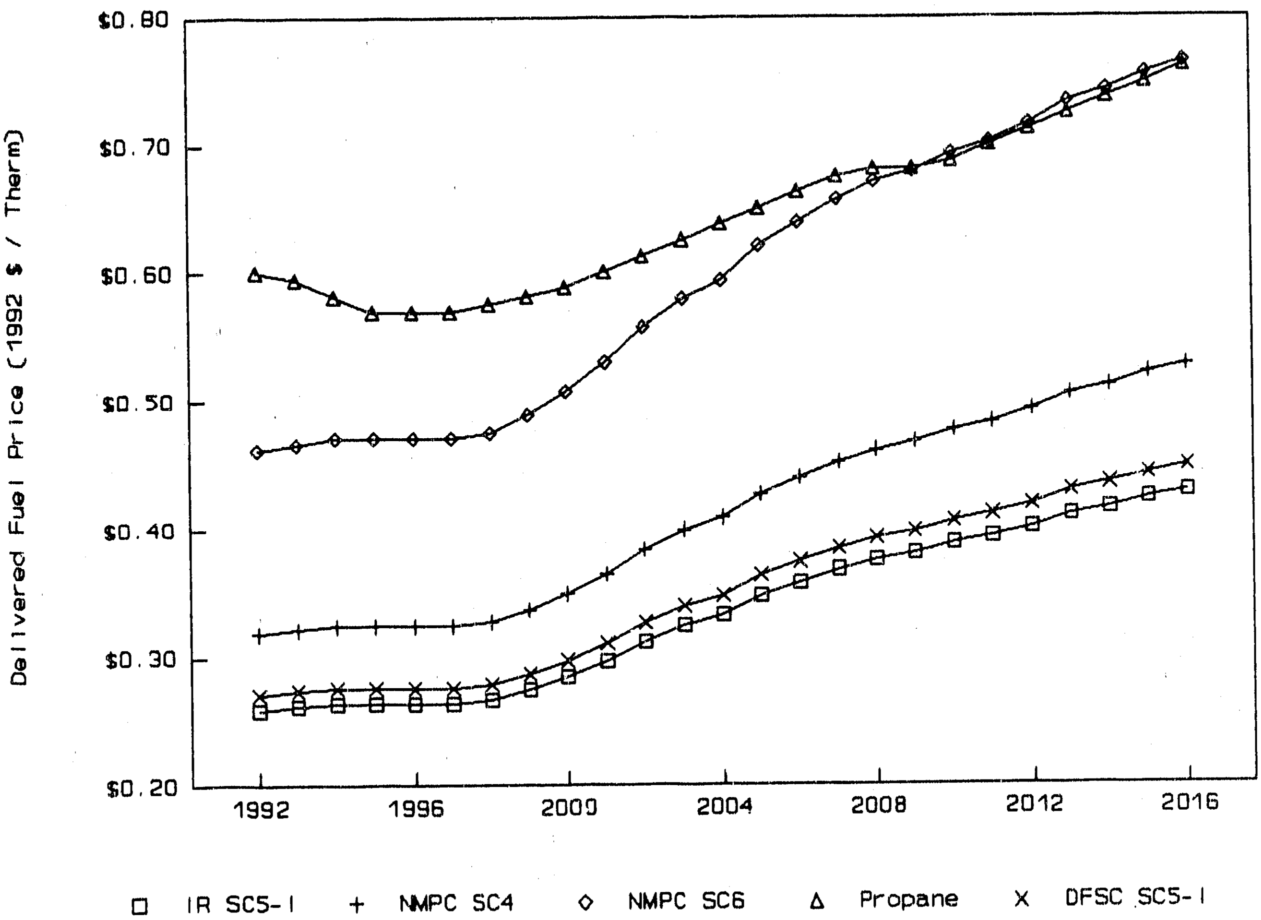

FIGURE 6.1. Delivered Fuel Price for Base and Interruption Scenarios, Strategies 1, 2, and 11

propane and SC6 rates under the base and interruption escalation rate and the same strategies under the high gas price escalation rate.

6.2 PROPANE-AIR STATION CAPITAL COST ESTIMATE

Capital cost figures for the propane air station were calculated by Combustion Services, Inc. Two estimates were calculated: the first assumed that the Old Fort conversion from fuel oil to natural gas did not occur, so that the propane air station would service only the New Fort area; and the second assumed that the conversion took place, and that the propane-air

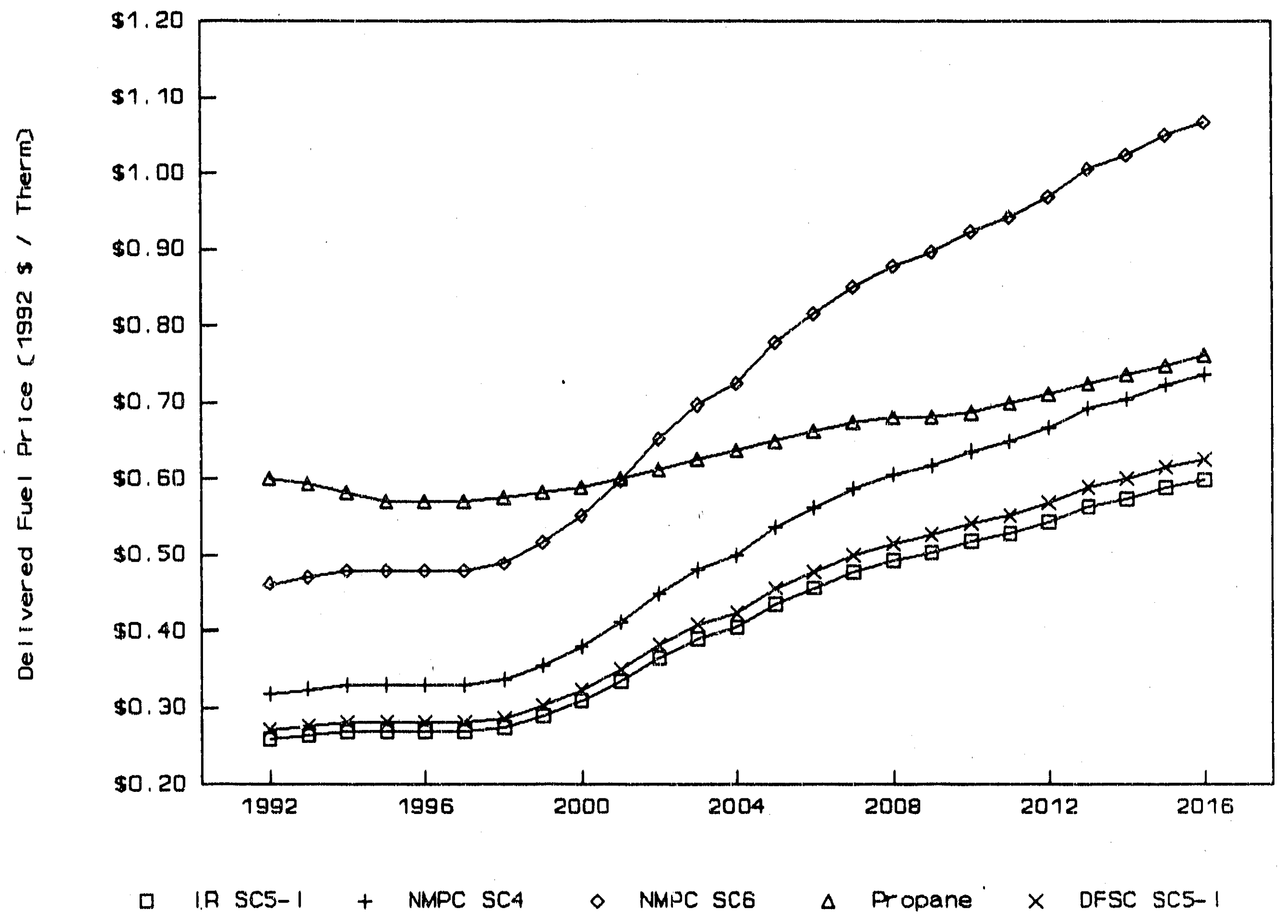

FIGURE 6.2. Delivered Fuel Price for High Gas Price Scenario, Strategies 1, 2, and 11

station would provide backup service for the entire Fort. Operation and maintenance (O&M) costs were derived from a study prepared for Fort Meade (Loria 1990).

The proposed air station would include two air compressors, two vaporizers, two air-assisted mixers, and four 90,000-gallon underground storage tanks for the New Fort or six 90,000-gallon underground storage tanks for the Entire Fort. The proposed system would yield a pressure of 15-20 psi, which meets the 15 psi distribution system at Fort Drum. Because of the high distribution pressure, air compressors and mixers are necessary to meet the required pressure. This added equipment increases the cost. If the New Fort were to be repiped to allow for a lower distribution pressure, or if the

Old Fort were converted and the gas lines installed built for lower pressure, the added equipment would not be necessary, which would result in a cost savings.

Another way in which cost savings could be introduced is by reducing the amount of storage. The system was designed for 15 days of propane storage, in accordance with Fort Drum's desire for extensive storage capacity. NMPC[a] and Combustion Services[b] suggest that 7 days would be sufficient; the propane supplier to Fort Drum, Agway, does not foresee any problems in making multiple deliveries as long as the reason for the natural gas interruption does not also affect propane.[c]

(a) Personal Communication, Janice Bailey, Supervisor, Customer Transportation, Niagara Mohawk Power Corporation. February 21, 1992.
(b) Personal Communication, Ray Self, Combustion Services Inc. May 26, 1992. 10:15 a.m.
(c) Personal Communication, Jim Trask, Propane Manager, Agway. May 26, 1992. 12:30 p.m.

7.0 RESULTS AND LIMITATIONS

This section provides the results, as well as the limitations, of the Fort Drum natural gas analysis.

7.1 ANALYSIS RESULTS

The analysis results indicate that Fort Drum can reduce its natural gas supply costs significantly while maintaining a reliable supply. For life-cycle cost calculations and detailed results, see Appendixes C and D.

The best immediately implementable strategy is for Fort Drum to purchase gas from DFSC and transport it under the SC5-I interruptible transportation rate and to build a propane-air station to provide supplemental gas during an NMPC interruption. Under the New Fort scenario, this strategy has an estimated net present value of $7.4 million, and estimated annual energy cost savings of $288,000 at current fuel and electricity prices.

The strategy with the largest net present value (NPV) is to transport natural gas through the Iroquois pipeline to NMPC under the large volume interruptible transportation rate (SC5-I), and to build a propane-air station to provide supplemental gas service in the case of an interruption. This strategy has a net present value of $8.4 million and annual energy cost savings of $353,000 at current fuel and electricity prices. The pipeline between Iroquois and NMPC will not be open until 1994, and Iroquois will not be accepting new customers until November 1993, so this strategy is not immediately available.

Because the best NPV strategies involve the construction of a propane-air station, a station should be researched in more detail. Assuming that a propane-air station is built, we recommend that Fort Drum purchase gas from the DFSC and switch to the NMPC SC5-I rate as soon as current contractual agreements allow, while beginning the process of becoming an Iroquois customer.

Under all scenarios, the strategy of transporting gas through Iroquois to NMPC under the large volume interruptible transportation rate presented the best net present value of investment. This strategy consistently did better than the others because of its lower costs per therm and because it was assumed that an NMPC supply interruption would not affect this strategy, and therefore there would be no need to purchase more costly supplemental gas from NMPC or to use propane.

The rankings of the remaining strategies fluctuated from scenario to scenario. The best immediately implementable strategy fluctuated between strategies 11 and 10. Both involve purchasing DFSC gas and transporting it under the interruptible NMPC SC5-I rate. The only difference is the use of NMPC supplemental SC6 gas versus the propane-air station, and the choice fluctuates as gas prices and the number of interruptions fluctuate. It is our recommendation that the Fort use whichever is less expensive at that time.

Following Strategies 11 and 10, Strategy 1 was the next best immediately implementable strategy under all scenarios. Although this strategy has a higher total cost per therm than the remaining immediately implementable strategies (Strategies 4 and 5), it is still preferable, as explained below.

It was assumed that under Strategy 1, with Fort Drum buying gas under NMPC's SC4 rate, no interruption of supply took place in the base case and the higher gas price case. In Strategies 4 and 5, which involved transportation from a supplier, however, it was assumed that, due to current capacity constraints at the broker-CNG supply point, a large amount of gas would need to be provided by either the propane-air station or through the purchase of supplemental gas from NMPC under the SC6 rate. This gas volume was enough to increase the price of fuel during the winter since both the propane and SC6 prices per therm are higher than that of SC4.

The results also show that the pipeline strategy moved from a negative to a positive NPV when the conversion of the Old Fort was assumed to take place because the increased volume of gas began to justify the large capital expenditure. Strategy 5, large volume interruptible transportation through CNG and NMPC with propane-air as the supplemental gas, presented a higher NPV under the High Gas Price Increase scenarios because a smaller percentage of their fuel is natural gas, but fell between the New Fort and Entire Fort scenarios because of the increased requirement for the more expensive fuel, propane.

The analysis results are summarized in Tables 7.1 through 7.6. The strategies are compared with the existing situation, Strategy 0.

7.2 LIMITATIONS OF THE ANALYSIS

Throughout the course of this analysis, we have attempted to clearly state all assumptions that were made. At this point, the limitations of the analysis will be condensed and discussed.

7.2.1 Strategy Limitations

To the best of our knowledge, the costs presented within this analysis are representative, but not necessarily inclusive, of actual costs involved. In particular, costs associated with the pipeline strategy are most likely

TABLE 7.1. Analysis Results: Base Case-New Fort (1992 $ thousands)

	Strategy	NPV of Investment	Annual Energy Cost Savings	Initial Capital Cost
1.	Large Volume Interruptible Rate with Propane Air Supplemental	5,461	192	950
2.	Interruptible Transportation, Iroquois to NMPC, with Propane Air Supplemental	8,416	353	950
3.	Interruptible Transportation, Iroquois to CNG to NMPC, with Propane Air Supplemental	6,754	261	950
4.	Interruptible Transportation, with NMPC Supplemental	4,167	117	950
5.	Interruptible Transportation, with Propane Air Supplemental	3,379	21	950
6.	Firm Transportation, Iroquois to NMPC, with NMPC Supplemental	3,859	214	0
7.	Firm Transportation, Iroquois to CNG to NMPC, with NMPC Supplemental	2,197	122	0
8.	Pipeline Connecting Iroquois to Fort Drum	-1,414	668	13,700
9.	DFSC, Firm Transportation, with NMPC Supplemental	2,856	160	0
10.	DFSC, Interruptible Transportation, with Propane Air Supplemental	6,889	353	950
11.	DFSC, Interruptible Transportation, with NMPC Supplemental	7,447	288	950

TABLE 7.2. Analysis Results: High Gas Price Forecast-New Fort (1992 $ thousands)

	Strategy	NPV of Investment	Annual Energy Cost Savings	Initial Capital Cost
1.	Large Volume Interruptible Rate with Propane Air Supplemental	6,616	192	950
2.	Interruptible Transportation, Iroquois to NMPC, with Propane Air Supplemental	10,152	353	950
3.	Interruptible Transportation, Iroquois to CNG to NMPC, with Propane Air Supplemental	8,190	261	950
4.	Interruptible Transportation, with NMPC Supplemental	5,121	117	950
5.	Interruptible Transportation, with Propane Air Supplemental	5,288	21	950
6.	Firm Transportation, Iroquois to NMPC, with NMPC Supplemental	4,571	214	0
7.	Firm Transportation, Iroquois to CNG to NMPC, with NMPC Supplemental	2,609	122	0
8.	Pipeline Connecting Iroquois to Fort Drum	673	668	13,700
9.	DFSC, Firm Transportation, with NMPC Supplemental	3,366	160	0
10.	DFSC, Interruptible Transportation, with Propane Air Supplemental	8,679	244	950
11.	DFSC, Interruptible Transportation, with NMPC Supplemental	9,167	288	950

TABLE 7.3. Analysis Results: NMPC Interruption-New Fort (1992 $ thousands)

	Strategy	NPV of Investment	Annual Energy Cost Savings	Initial Capital Cost
1.	Large Volume Interruptible Rate with Propane Air Supplemental	4,882	147	950
2.	Interruptible Transportation, Iroquois to NMPC, with Propane Air Supplemental	8,416	353	950
3.	Interruptible Transportation, Iroquois to CNG to NMPC, with Propane Air Supplemental	6,754	261	950
4.	Interruptible Transportation, with NMPC Supplemental	3,882	90	950
5.	Interruptible Transportation, with Propane Air Supplemental	3,379	21	950
6.	Firm Transportation, Iroquois to NMPC, with NMPC Supplemental	3,859	214	0
7.	Firm Transportation, Iroquois to CNG to NMPC, with NMPC Supplemental	2,197	122	0
8.	Pipeline Connecting Iroquois to Fort Drum	-1,414	668	13,700
9.	DFSC, Firm Transportation, with NMPC Supplemental	2,856	160	0
10.	DFSC, Interruptible Transportation, with Propane Air Supplemental	6,905	236	950
11.	DFSC, Interruptible Transportation, with NMPC Supplemental	5,614	160	950

TABLE 7.4. Analysis Results: Base Case-Entire Fort (1992 $ thousands)

	Strategy	NPV of Investment	Annual Energy Cost Savings	Initial Capital Cost
1.	Large Volume Interruptible Rate with Propane Air Supplemental	16,761	764	1,393
2.	Interruptible Transportation, Iroquois to NMPC, with Propane Air Supplemental	23,647	1,138	1,393
3.	Interruptible Transportation, Iroquois to CNG to NMPC, with Propane Air Supplemental	19,682	917	1,393
4.	Interruptible Transportation, with NMPC Supplemental	9,783	370	1,393
5.	Interruptible Transportation, with Propane Air Supplemental	5,030	-190	1,393
6.	Firm Transportation, Iroquois to NMPC, with NMPC Supplemental	11,746	650	0
7.	Firm Transportation, Iroquois to CNG to NMPC, with NMPC Supplemental	7,780	428	0
8.	Pipeline Connecting Iroquois to Fort Drum	17,582	1,730	13,700
9.	DFSC, Firm Transportation, with NMPC Supplemental	4,796	555	0
10.	DFSC, Interruptible Transportation, with Propane Air Supplemental	20,672	939	1,393
11.	DFSC, Interruptible Transportation, with NMPC Supplemental	21,397	1,025	1,393

TABLE 7.5. Analysis Results: High Gas Price Forecast-Entire Fort (1992 $ thousands)

	Strategy	NPV of Investment	Annual Energy Cost Savings	Initial Capital Cost
1.	Large Volume Interruptible Rate with Propane Air Supplemental	20,020	764	1,393
2.	Interruptible Transportation, Iroquois to NMPC, with Propane Air Supplemental	28,298	1,138	1,393
3.	Interruptible Transportation, Iroquois to CNG to NMPC, with Propane Air Supplemental	23,617	917	1,393
4.	Interruptible Transportation, with NMPC Supplemental	11,842	370	1,393
5.	Interruptible Transportation, with Propane Air Supplemental	12,164	-190	1,393
6.	Firm Transportation, Iroquois to NMPC, with NMPC Supplemental	13,955	650	0
7.	Firm Transportation, Iroquois to CNG to NMPC, with NMPC Supplemental	9,274	428	0
8.	Pipeline Connecting Iroquois to Fort Drum	23,069	1,730	13,700
9.	DFSC, Firm Transportation, with NMPC Supplemental	11,453	552	0
10.	DFSC, Interruptible Transportation, with Propane Air Supplemental	25,489	939	1,393
11.	DFSC, Interruptible Transportation, with NMPC Supplemental	25,406	1022	1,393

TABLE 7.6. Analysis Results: NMPC Interruption-Entire Fort (1992 $ thousands)

	Strategy	NPV of Investment	Annual Energy Cost Savings	Initial Capital Cost
1.	Large Volume Interruptible Rate with Propane Air Supplemental	15,747	684	1,393
2.	Interruptible Transportation, Iroquois to NMPC, with Propane Air Supplemental	23,647	1,138	1,393
3.	Interruptible Transportation, Iroquois to CNG to NMPC, with Propane Air Supplemental	19,682	917	1,393
4.	Interruptible Transportation, with NMPC Supplemental	9,288	319	1,393
5.	Interruptible Transportation, with Propane Air Supplemental	5,030	-190	1,393
6.	Firm Transportation, Iroquois to NMPC, with NMPC Supplemental	11,746	650	0
7.	Firm Transportation, Iroquois to CNG to NMPC, with NMPC Supplemental	7,780	428	0
8.	Pipeline Connecting Iroquois to Fort Drum	17,582	1,730	13,700
9.	DFSC, Firm Transportation, with NMPC Supplemental	4,796	555	0
10.	DFSC, Interruptible Transportation, with Propane Air Supplemental	21,043	924	1,393
11.	DFSC, Interruptible Transportation, with NMPC Supplemental	18,088	791	1,393

underestimated. There would most likely be additional regulatory and administrative costs associated with the building of a pipeline. In essence, this strategy would turn Fort Drum into a small utility company. The fact that customers rarely build their own pipelines indicates that we have not fully captured the costs of this strategy.

Canadian gas prices and the Canadian natural gas market are also not necessarily representative of the actual situation. We do not know much about the contracting and purchasing of Canadian natural gas, nor of the gas market and pricing trends within that country. In the analysis, only one rate for Canadian natural gas was assumed for each year, since it was unclear whether or not Canadian gas prices fluctuate seasonally. The regulations for the natural gas market most likely also vary between the U.S. and Canada. For example, only about 20% of all Canadian gas moves on the spot market, as compared with approximately 80% in the U.S.[a]

(a) Personal Communication, Mike Wedel, Manager of Marketing, BP Canada. April 1, 1992. 2:00 p.m.

Other limitations dealing with the propane-air station and pipeline capacities are discussed in more detail below.

7.2.2 Propane-Air Station

The primary concern involved with the propane-air station is that the storage capacity may be excessive. Propane supply has been reliable in the past, and the propane supplier does not foresee any problems in multiple deliveries during the time in which the station would be operated, so it is likely that 7 days of storage would suffice, thus reducing the cost of storage by 50%.

7.2.3 Pipeline Capacity Constraints

In February 1992, we set out to document all past supply interruptions. Hudson Bay NGC told us that they had that information and would send it to us; however, we have not heard from them since, despite 11 phone calls and numerous messages.

NMPC has indicated that it is not running at full capacity, and also that it is in the process of expanding current capacity to meet the forecasted future needs of its customers. CNG has capacity within parts of its pipeline, and meeting Fort Drum's current and forecasted gas demand should not be a problem once the gas is in CNG's pipeline, but there is currently a transportation bottleneck located at CNG's Ohio terminus. It was assumed that this is where the broker feeds the gas supply for Fort Drum into the CNG line, but we were unable to confirm this.

7.2.4 Unexplored Strategies

Near the end of the analysis, a potential new set of strategies surfaced. It would be possible for Fort Drum to purchase Canadian natural gas, transport it over the Trans Canada pipeline, and move it on to the CNG pipeline at the Buffalo terminus, and then transport the gas through NMPC to Fort Drum. This option would present itself to at least two new strategies: the transportation of gas under NMPC SC8, and the transportation of gas under NMPC SC5-I. These strategies would avoid the transportation bottleneck in Ohio.

Another method of potential cost reduction that was not explored was that of alternative brokers. It was assumed that, because the broker portion of the contract is open for bidding, the company with the lowest bid would be chosen. Therefore, the figures from the current contract with Hudson Bay were assumed to be representative of brokerage costs. We recognize that this may not be the case, however, so it is suggested that when a broker is needed, the contract be put up for bid again. With many potential strategies involving the purchase of Canadian natural gas, there may be more brokerages that could become involved.

8.0 <u>REFERENCES</u>

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APPENDIX A

<u>NIAGARA MOHAWK POWER CORPORATION RATE SCHEDULE</u>

energy decisions

Explanation of Service Classifications

October 1991 Rev. 7

SC1 Residential Natural Gas Service

First 3 Therms or less	$5.81
Next 37 Therms, per Therm	.72475
Over 40 Therms, per Therm	.55207

Characteristics of Service

- Available in all territory served.
- Term of Service: For residential service without building heating, customer may terminate service after three days notice to Company. For all other service, one year and, thereafter, until cancelled.

Characteristics of Rate

- 30 day minimum charge is $5.81
- Subject to the Gas Adjustment Clause.

SC2 Small General Natural Gas Service

First 3 Therms or less	$5.81
Next 37 Therms, per Therm	.72475
Next 240 Therms, per Therm	.62300
Additional Therms, per Therm	.55339

Characteristics of Service

- Available in all territory served when Niagara Mohawk has suitable and adequate facilities for the load.
- Term of Service: One year and, thereafter, until cancelled.

Characteristics of Rate

- 30-day minimum charge is $5.81
- Subject to the Gas Adjustment Clause.

SC3-Large General Natural Gas Service

First 7,200 Therms or less	$3,894.00
Next 92,800 Therms, per Therm	.4662
Additional Therms, per Therm	.4452

Characteristics of Service

- Available in all territory served when Niagara Mohawk has suitable and adequate facilities for the load.
- Term of Service: One year and, thereafter, until cancelled.

Characteristics of Rate

- 30-day minimum charge, no less than $3,894.00, subject to conditions defined in the tariff.
- Subject to the Gas Adjustment Clause.

SC4-Large Volume Interruptible Natural Gas Service

Characteristics of Service

- Large volume requirements for customers who use not less than 2,500,000 Therms per year.
- Totally Interruptible
- Gas supplied by Niagara Mohawk
- Service available to customers who maintain standby facilities (including fuel) adequate to enable satisfactory operation of facilities wherever and so long as gas supply is interrupted.
- Term of Service: One year initially and renewable on a yearly basis until cancelled on prior 90 day written notice by the Company or Customer.

Characteristics of Rate

- Calendar month minimum charge will be no less than $825.00 subject to conditions defined in the tariff.
- Calendar month rate per Dt set monthly at Niagara Mohawk's discretion, but subject to boundaries defined in the tariff as not less than the monthly Adjusted Commodity Cost of Gas (floor price) and not more than the Firm Gas Price (ceiling price).

SC5-Large Volume Gas Transportation Service

SC5-(Firm)
Minimum 250,000 Therms but not greater than 1,000,000/ Year

Parameters

- Rate is $0.05975/Therm plus a Pipeline Suppliers Adjustment per Therm (Take or Pay, Cove Point LNG) and a Demand Cost Adjustment if the right to return to "Sales Customer" status is elected.
- Customer must take SC6 Supplemental Gas Service for Gas Transportation Service Customers.

SC5-I (Interruptible)
Minimum 2,500,000 Therms/ Year

Parameters

- Service available only to those customers who would otherwise qualify for SC No. 4, large volume interruptible service.
- Market based rate with a floor of $0.010/Therm and a ceiling of $0.05975/Therm.
- Customer must take SC6 Supplemental Gas Service for Gas Transportation Service Customers.
- Subject to Pipeline Suppliers Adjustment (Take or Pay, Cove Point LNG.)

Characteristics of Service

- Firm Transportation of Customer owned gas in minimum annual quantities of not less than 250,000 Therms.
- Customers are subject to rollover balancing provisions and associated charges.

- Interruptible transportation of customer owned gas on a "Best Efforts" basis by Niagara Mohawk in minimum annual quantities of not less than 2,500,000 Therms.
- Delivery of Customer owned Gas will be at a pressure approved by Niagara Mohawk.
- Customer owned Gas must be of pipeline quality, having a minimum BTU value of 1018 BTU per cubic foot on a dry basis.
- Customer owned gas will be converted from volumetric measurement in CCF to Therm measurement, 100,000 BTU per Therm on a dry basis, if required, at the point the customer owned gas enters Niagara Mohawk's distribution system, as outlined in the tariff.
- Customer taking firm transportation service may retain the right to return to a "Sales Customer" status by paying an additional Demand Cost Adjustment for each therm of gas transported.
- Term of Service: For Firm Transportation Service one year initially renewable on a year-to-year basis. For Interruptible Transportation service up to one year initially and renewable up to one year, thereafter. Cancellation requires written notice by Niagara Mohawk or Customer 30 days prior to the expiration of the term of service.

Characteristics of Rate

- For Interruptible Transportation Service, the Calendar month rate will be determined at the sole discretion of Niagara Mohawk and will not exceed the firm transportation rate or be less than $0.010 per Therm. Rate is effective on the first calendar day of each month
- Term of Rate: For firm service, one year initially and renewable on a year-to-year basis, thereafter. For interruptible service, up to one year initially and renewable up to one year, thereafter. Cancellation requires written notice by Niagara Mohawk or the customer 30 days prior to expiration of term of service.
- Service on both Firm and Interruptible basis is provide according to the special provisions outlined in the tariff.

SC6-Supplemental Gas Service for Gas Transportation Service Customers

First 3 Therms or less	$5.81
Next 37 Therms, per Therm	.72475
Next 240 Therms, per Therm	.62300
Next 6,920 Therms, per Therm	.55339
Next 92,800 Therms, per Therm	.46620
Over 100,000 Therms, per Therm	.44520

Characteristics of Service

- Supplemental Gas Service available only to those Customers taking service under SC5, SC7, or SC8 Gas Transportation Services.
- Service in continuous except as provided in the tariff.

Characteristics of Rate

- Subject to the Gas Adjustment Clause.

SC7-Low Volume Gas Transportation Service

First 2,100 Therms or Less	$252.00
Over 2,100 Therms, per Therm	$0.12

Plus a Pipeline Suppliers Adjustment Rate per Therm (Cove Point, Take-or-Pay) and a Demand Gas Cost Adjustment if the right to return to "Sales Customer" status is elected.

Customer must take SC6 Supplemental Service for Gas Transportation Service Customers.

Characteristics of Service

- Firm Transportation of Customer owned gas in minimum annual quantities of not less than 50,000 Therms.
- Delivery of Customer owned gas will be at a pressure approved by Niagara Mohawk
- Customer owned gas will be converted from volumetric measurement in CCF to Therm measurement, if required, at the point the gas enters Niagara Mohawk's distribution system.
- Term of Service: One year initially and renewable on a year-to-year basis, thereafter, until cancelled on a prior thirty-day written notice by Niagara Mohawk or the Customer.
- Customers are subject to rollover balancing provisions and associated charges.

SC8- Transportation Service with Standby Sales Service

- Mandatory for firm transportation of customer owned gas for customers who are capable of consuming at least 1,000,000 therms annually.
- Customers have the option to contract for any level of standby sales volumes. Selecting this option requires the customer to nominate daily and annual contract demand levels from zero to one-hundred percent of the customer's requirements. Nominations are subject to specific provisions.
- Customers must take SC6 Supplemental Gas Service which is available on a best efforts, interruptible basis.
- Customers are subject to rollover balancing provisions and associated charges.
- Transportation volumes are subject to the Calendar Month Rate of $.05975/Thm., plus supplier adjustment surcharges
- Standby sales are subject to the Calendar Month Rate and the current commodity cost of gas. Nominated contract demand levels are subject to variable monthly demand-related charges and are applicable whether or not actual standby sales are taken
- Customers are responsible for the cost of all required equipment and associated installation costs.
- The term of service is one year initially and renewable on a year to year basis. Cancellation requires written notice by the Company or Customer thirty days prior to the expiration of the annual term of service.
- Customers served on the classification are eligible for various economic development discount programs.

General Information About Niagara Mohawk Rates

- Rates are stated on the basis of a 30-day month — if during your billing period your meter reading is less than or more than 30 days, charges are prorated on the basis of the number of days in the billing period.
- Gas Adjustment Clause (GAC) — An adjustment per unit of use (Therm) reflecting the portion of the average cost of gas not included in the base rates.
- Gross Revenue Tax — Niagara Mohawk is required to pay a State 3.5% Gross Income Tax and a .75% Gross Earnings Tax which may be modified by new laws such as the 15% temporary increase imposed by the New York State Legislature for the years 1990 thru 1992. In addition, certain cities and villages also charge a 1% or 2% Municipal Gross Income Tax. The rates for all service classes stated above are adjusted by a tax factor to recover these taxes. These revenue taxes are applied to all rates and charges with the exception of sales tax. To derive the charges including revenue taxes the rates stated are divided by applicable revenue tax factor depending on the tax district in which service is provided. Your local Niagara Mohawk office will provide information about revenue taxes at your service address.

If you would like more detailed information about a specific Service Classification, please contact your local Niagara Mohawk business office to request that this information be mailed to you

Note: The aforementioned rates are brief excerpts of Niagara Mohawk's filed tariffs in effect as of the time of printing

APPENDIX B

PRICE ESCALATION RATES

APPENDIX B

PRICE ESCALATION RATES

Tables B.1 and B.2 contain the escalation rates and prices for the Base, Interruption, and High Gas Price scenarios. Tables B.3 and B.4 contain the average delivered fuel prices for the scenarios over the 25-year period.

TABLE B.1. Escalation Rates - Base and Interruption Scenarios

	DOE Escalation Rates		
Year	Commercial Natural Gas	Residential LPG	Commercial Electricity
1992	1.00	1.00	1.00
1993	1.01	0.99	1.00
1994	1.02	0.97	1.01
1995	1.02	0.95	0.98
1996	1.02	0.95	0.96
1997	1.02	0.95	0.95
1998	1.03	0.96	0.94
1999	1.06	0.97	0.93
2000	1.10	0.98	0.94
2001	1.15	1.00	0.94
2002	1.21	1.02	0.94
2003	1.25	1.04	0.94
2004	1.28	1.06	0.94
2005	1.34	1.08	0.95
2006	1.38	1.10	0.95
2007	1.42	1.12	0.96
2008	1.45	1.13	0.96
2009	1.47	1.13	0.95
2010	1.50	1.14	0.96
2011	1.52	1.16	0.97
2012	1.55	1.19	0.97
2013	1.59	1.21	0.97
2014	1.61	1.23	0.98
2015	1.64	1.25	0.98
2016	1.66	1.27	0.98

TABLE B.1. (contd)

Year	Gulf Coast Natural Gas Winter Rate	Gulf Coast Natural Gas Summer Rate	City-Gate Natural Gas Winter Rate	City-Gate Natural Gas Summer Rate	Canadian Gas Price
1992	$0.180	$0.134	$0.312	$0.231	$0.134
1993	$0.182	$0.135	$0.315	$0.233	$0.135
1994	$0.184	$0.137	$0.318	$0.236	$0.136
1995	$0.184	$0.137	$0.318	$0.236	$0.136
1996	$0.184	$0.137	$0.318	$0.236	$0.136
1997	$0.184	$0.137	$0.318	$0.236	$0.136
1998	$0.185	$0.138	$0.321	$0.238	$0.138
1999	$0.191	$0.142	$0.330	$0.245	$0.142
2000	$0.198	$0.147	$0.343	$0.254	$0.147
2001	$0.206	$0.154	$0.358	$0.265	$0.153
2002	$0.217	$0.162	$0.376	$0.279	$0.161
2003	$0.226	$0.168	$0.392	$0.290	$0.168
2004	$0.231	$0.172	$0.401	$0.297	$0.172
2005	$0.242	$0.180	$0.419	$0.310	$0.180
2006	$0.249	$0.185	$0.431	$0.319	$0.185
2007	$0.256	$0.190	$0.444	$0.328	$0.190
2008	$0.261	$0.194	$0.453	$0.335	$0.194
2009	$0.265	$0.197	$0.459	$0.340	$0.197
2010	$0.270	$0.201	$0.468	$0.347	$0.201
2011	$0.274	$0.204	$0.474	$0.351	$0.203
2012	$0.279	$0.208	$0.483	$0.358	$0.207
2013	$0.286	$0.213	$0.496	$0.367	$0.212
2014	$0.289	$0.215	$0.502	$0.371	$0.215
2015	$0.295	$0.219	$0.511	$0.378	$0.219
2016	$0.298	$0.222	$0.517	$0.383	$0.222

Year	SC5-I Transport	SC8 Transport	Broker Transport Winter Rate	Broker Transport Summer Rate	SC6 Gas & Transport Tier 1
1992	$0.0388	$0.0728	$0.1039	$0.0858	$5.81
1993	$0.0392	$0.0735	$0.1049	$0.0866	$5.87
1994	$0.0396	$0.0742	$0.1059	$0.0875	$5.92
1995	$0.0396	$0.0742	$0.1059	$0.0875	$5.92
1996	$0.0396	$0.0742	$0.1059	$0.0875	$5.92
1997	$0.0396	$0.0742	$0.1059	$0.0875	$5.92
1998	$0.0399	$0.0749	$0.1070	$0.0883	$5.98
1999	$0.0411	$0.0770	$0.1100	$0.0908	$6.15
2000	$0.0426	$0.0799	$0.1141	$0.0942	$6.38
2001	$0.0445	$0.0835	$0.1192	$0.0984	$6.66
2002	$0.0468	$0.0877	$0.1253	$0.1035	$7.01
2003	$0.0487	$0.0913	$0.1304	$0.1077	$7.29
2004	$0.0498	$0.0935	$0.1334	$0.1102	$7.46
2005	$0.0521	$0.0977	$0.1396	$0.1152	$7.80
2006	$0.0536	$0.1006	$0.1436	$0.1186	$8.03

TABLE B.1. (contd)

Year	SC5-I Transport	SC8 Transport	Broker Transport Winter Rate	Broker Transport Summer Rate	SC6 Gas & Transport Tier 1
2007	$0.0552	$0.1034	$0.1477	$0.1220	$8.26
2008	$0.0563	$0.1056	$0.1508	$0.1245	$8.43
2009	$0.0571	$0.1070	$0.1528	$0.1262	$8.54
2010	$0.0582	$0.1091	$0.1559	$0.1287	$8.72
2011	$0.0590	$0.1106	$0.1579	$0.1304	$8.83
2012	$0.0601	$0.1127	$0.1609	$0.1329	$9.00
2013	$0.0616	$0.1156	$0.1650	$0.1363	$9.23
2014	$0.0624	$0.1170	$0.1671	$0.1380	$9.34
2015	$0.0635	$0.1191	$0.1701	$0.1405	$9.51
2016	$0.0643	$0.1206	$0.1721	$0.1422	$9.63

SC6 Gas and Transportation, Continued

Year	Tier 2	Tier 3	Tier 4	Tier 5	Tier 6
1992	$0.72475	$0.62300	$0.55339	$0.46620	$0.4452
1993	$0.73186	$0.62911	$0.55882	$0.47077	$0.44956
1994	$0.73896	$0.63522	$0.56424	$0.47534	$0.45393
1995	$0.73896	$0.63522	$0.56424	$0.47534	$0.45393
1996	$0.73896	$0.63522	$0.56424	$0.47534	$0.45393
1997	$0.73896	$0.63522	$0.56424	$0.47534	$0.45393
1998	$0.74607	$0.64132	$0.56967	$0.47991	$0.45829
1999	$0.76738	$0.65965	$0.58594	$0.49362	$0.47139
2000	$0.79580	$0.68408	$0.60764	$0.51191	$0.48885
2001	$0.83133	$0.71462	$0.63477	$0.53476	$0.51067
2002	$0.87396	$0.75126	$0.66732	$0.56218	$0.53686
2003	$0.90949	$0.78180	$0.69445	$0.58504	$0.55868
2004	$0.93081	$0.80013	$0.71073	$0.59875	$0.57178
2005	$0.97344	$0.83677	$0.74328	$0.62617	$0.59796
2006	$1.00186	$0.86121	$0.76498	$0.64445	$0.61542
2007	$1.03028	$0.88564	$0.78668	$0.66274	$0.63288
2008	$1.05160	$0.90396	$0.80296	$0.67645	$0.64598
2009	$1.06581	$0.91618	$0.81381	$0.68559	$0.65471
2010	$1.08713	$0.93450	$0.83009	$0.69930	$0.66780
2011	$1.10134	$0.94672	$0.84094	$0.70844	$0.67653
2012	$1.12265	$0.96504	$0.85721	$0.72215	$0.68962
2013	$1.15107	$0.98947	$0.87891	$0.74044	$0.70708
2014	$1.16528	$1.00169	$0.88976	$0.74958	$0.71581
2015	$1.18660	$1.02001	$0.90604	$0.76329	$0.72891
2016	$1.20081	$1.03223	$0.91689	$0.77243	$0.73764

TABLE B.1. (contd)

Year	SC8 Demand Chg ($/therm)	CNG Transport	Iroquois Commodity Charge	Iroquois Demand Chg ($/therm)	Propane Price
1992	$0.0794	$0.0332	$0.01263	$0.0659	$0.6004
1993	$0.0802	$0.0335	$0.01275	$0.0665	$0.5942
1994	$0.0810	$0.0339	$0.01288	$0.0672	$0.5818
1995	$0.0810	$0.0339	$0.01288	$0.0672	$0.5695
1996	$0.0810	$0.0339	$0.01288	$0.0672	$0.5695
1997	$0.0810	$0.0339	$0.01288	$0.0672	$0.5695
1998	$0.0817	$0.0342	$0.01300	$0.0678	$0.5756
1999	$0.0841	$0.0352	$0.01337	$0.0697	$0.5818
2000	$0.0872	$0.0365	$0.01387	$0.0723	$0.5880
2001	$0.0911	$0.0381	$0.01449	$0.0755	$0.6004
2002	$0.0957	$0.0400	$0.01523	$0.0794	$0.6128
2003	$0.0996	$0.0417	$0.01585	$0.0826	$0.6252
2004	$0.1020	$0.0426	$0.01622	$0.0846	$0.6375
2005	$0.1066	$0.0446	$0.01696	$0.0885	$0.6499
2006	$0.1098	$0.0459	$0.01746	$0.0910	$0.6623
2007	$0.1129	$0.0472	$0.01795	$0.0936	$0.6747
2008	$0.1152	$0.0482	$0.01833	$0.0956	$0.6809
2009	$0.1168	$0.0488	$0.01857	$0.0969	$0.6809
2010	$0.1191	$0.0498	$0.01895	$0.0988	$0.6871
2011	$0.1207	$0.0505	$0.01919	$0.1001	$0.6994
2012	$0.1230	$0.0514	$0.01956	$0.1020	$0.7118
2013	$0.1261	$0.0527	$0.02006	$0.1046	$0.7242
2014	$0.1277	$0.0534	$0.02031	$0.1059	$0.7366
2015	$0.1300	$0.0544	$0.02068	$0.1078	$0.7490
2016	$0.1316	$0.0550	$0.02093	$0.1091	$0.7613

Year	Electricity $/kWh	Electricity Demand Chg. $/kW	New York State Import Tax	DFSC Gas Winter	DFSC Gas Summer
1992	$0.0506	$5.51	$0.0079	$0.229	$0.215
1993	$0.0506	$5.51	$0.0080	$0.232	$0.218
1994	$0.0511	$5.57	$0.0081	$0.234	$0.220
1995	$0.0496	$5.40	$0.0081	$0.234	$0.220
1996	$0.0486	$5.29	$0.0081	$0.234	$0.220
1997	$0.0480	$5.23	$0.0081	$0.234	$0.220
1998	$0.0475	$5.18	$0.0082	$0.236	$0.222
1999	$0.0470	$5.12	$0.0084	$0.243	$0.228
2000	$0.0475	$5.18	$0.0087	$0.252	$0.237
2001	$0.0475	$5.18	$0.0091	$0.263	$0.247
2002	$0.0475	$5.18	$0.0096	$0.277	$0.260
2003	$0.0475	$5.18	$0.0100	$0.288	$0.270
2004	$0.0475	$5.18	$0.0102	$0.295	$0.277
2005	$0.0480	$5.23	$0.0107	$0.308	$0.289
2006	$0.0480	$5.23	$0.0110	$0.317	$0.298

TABLE B.1. (contd)

Year	Electricity $/kWh	Electricity Demand Chg. $/kW	New York State Import Tax	DFSC Gas Winter	DFSC Gas Summer
2007	$0.0486	$5.29	$0.0113	$0.326	$0.306
2008	$0.0486	$5.29	$0.0115	$0.333	$0.313
2009	$0.0480	$5.23	$0.0117	$0.337	$0.317
2010	$0.0486	$5.29	$0.0119	$0.344	$0.323
2011	$0.0491	$5.34	$0.0121	$0.348	$0.327
2012	$0.0491	$5.34	$0.0123	$0.355	$0.334
2013	$0.0491	$5.34	$0.0126	$0.364	$0.342
2014	$0.0496	$5.40	$0.0128	$0.369	$0.346
2015	$0.0496	$5.40	$0.0130	$0.375	$0.353
2016	$0.0496	$5.40	$0.0132	$0.380	$0.357

TABLE B.2. Escalation Rates - High Gas Price Scenario

Year	DOE Escalation Rates: Commercial Natural Gas	Residential LPG	Commercial Electricity
1992	1.00	1.00	1.00
1993	1.02	0.99	1.00
1994	1.04	0.97	1.01
1995	1.04	0.95	0.98
1996	1.04	0.95	0.96
1997	1.04	0.95	0.95
1998	1.06	0.96	0.94
1999	1.12	0.97	0.93
2000	1.20	0.98	0.94
2001	1.29	1.00	0.94
2002	1.41	1.02	0.94
2003	1.51	1.04	0.94
2004	1.57	1.06	0.94
2005	1.69	1.08	0.95
2006	1.76	1.10	0.95
2007	1.84	1.12	0.96
2008	1.90	1.13	0.96
2009	1.94	1.13	0.95
2010	2.00	1.14	0.96
2011	2.04	1.16	0.97
2012	2.10	1.19	0.97
2013	2.18	1.21	0.97
2014	2.22	1.23	0.98
2015	2.27	1.25	0.98
2016	2.31	1.27	0.98

Year	City-Gate Natural Gas Winter Rate	City-Gate Natural Gas Summer Rate	Gulf Coast Natural Gas Winter Rate	Gulf Coast Natural Gas Summer Rate	Canadian Gas Price
1992	$0.312	$0.231	$0.180	$0.134	$0.134
1993	$0.318	$0.236	$0.184	$0.137	$0.136
1994	$0.324	$0.240	$0.187	$0.139	$0.139
1995	$0.324	$0.240	$0.187	$0.139	$0.139
1996	$0.324	$0.240	$0.187	$0.139	$0.139
1997	$0.324	$0.240	$0.187	$0.139	$0.139
1998	$0.330	$0.245	$0.191	$0.142	$0.142
1999	$0.349	$0.258	$0.201	$0.150	$0.149
2000	$0.373	$0.276	$0.215	$0.160	$0.160
2001	$0.404	$0.299	$0.233	$0.173	$0.173
2002	$0.440	$0.326	$0.254	$0.189	$0.189
2003	$0.471	$0.349	$0.272	$0.202	$0.202
2004	$0.489	$0.362	$0.282	$0.210	$0.210
2005	$0.526	$0.390	$0.304	$0.226	$0.225
2006	$0.551	$0.408	$0.318	$0.236	$0.236

TABLE B.2. (contd)

Year	City-Gate Natural Gas Winter Rate	City-Gate Natural Gas Summer Rate	Gulf Coast Natural Gas Winter Rate	Gulf Coast Natural Gas Summer Rate	Canadian Gas Price
2007	$0.575	$0.426	$0.332	$0.247	$0.246
2008	$0.593	$0.439	$0.342	$0.255	$0.254
2009	$0.606	$0.448	$0.349	$0.260	$0.260
2010	$0.624	$0.462	$0.360	$0.268	$0.267
2011	$0.636	$0.471	$0.367	$0.273	$0.273
2012	$0.655	$0.485	$0.378	$0.281	$0.281
2013	$0.679	$0.503	$0.392	$0.292	$0.291
2014	$0.691	$0.512	$0.399	$0.297	$0.296
2015	$0.710	$0.525	$0.409	$0.305	$0.304
2016	$0.722	$0.534	$0.416	$0.310	$0.309

Year	SC5-I Transport	SC8 Transport	Broker Transport Winter Rate	Broker Transport Summer Rate	SC6 Gas & Transport Tier 1
1992	$0.0388	$0.0728	$0.1039	$0.0858	$5.81
1993	$0.0396	$0.0742	$0.1059	$0.0875	$5.92
1994	$0.0403	$0.0756	$0.1080	$0.0892	$6.04
1995	$0.0403	$0.0756	$0.1080	$0.0892	$6.04
1996	$0.0403	$0.0756	$0.1080	$0.0892	$6.04
1997	$0.0403	$0.0756	$0.1080	$0.0892	$6.04
1998	$0.0411	$0.0770	$0.1100	$0.0908	$6.15
1999	$0.0434	$0.0813	$0.1161	$0.0959	$6.49
2000	$0.0464	$0.0870	$0.1243	$0.1026	$6.95
2001	$0.0502	$0.0942	$0.1345	$0.1110	$7.52
2002	$0.0548	$0.1027	$0.1467	$0.1211	$8.20
2003	$0.0586	$0.1099	$0.1569	$0.1295	$8.77
2004	$0.0609	$0.1141	$0.1630	$0.1346	$9.11
2005	$0.0654	$0.1227	$0.1752	$0.1447	$9.80
2006	$0.0685	$0.1284	$0.1834	$0.1514	$10.25
2007	$0.0715	$0.1341	$0.1915	$0.1581	$10.71
2008	$0.0738	$0.1384	$0.1976	$0.1632	$11.05
2009	$0.0753	$0.1412	$0.2017	$0.1666	$11.28
2010	$0.0776	$0.1455	$0.2078	$0.1716	$11.62
2011	$0.0791	$0.1484	$0.2119	$0.1750	$11.85
2012	$0.0814	$0.1527	$0.2180	$0.1800	$12.19
2013	$0.0844	$0.1584	$0.2261	$0.1867	$12.65
2014	$0.0860	$0.1612	$0.2302	$0.1901	$12.87
2015	$0.0883	$0.1655	$0.2363	$0.1952	$13.21
2016	$0.0898	$0.1684	$0.2404	$0.1985	$13.44

TABLE B.2. (contd)

SC6 Gas and Transportation, Continued

Year	Tier 2	Tier 3	Tier 4	Tier 5	Tier 6
1992	$0.72475	$0.62300	$0.55339	$0.46620	$0.44520
1993	$0.73896	$0.63522	$0.56424	$0.47534	$0.45393
1994	$0.75317	$0.64743	$0.57509	$0.48448	$0.46266
1995	$0.75317	$0.64743	$0.57509	$0.48448	$0.46266
1996	$0.75317	$0.64743	$0.57509	$0.48448	$0.46266
1997	$0.75317	$0.64743	$0.57509	$0.48448	$0.46266
1998	$0.76738	$0.65965	$0.58594	$0.49362	$0.47139
1999	$0.81001	$0.69629	$0.61849	$0.52105	$0.49758
2000	$0.86686	$0.74516	$0.66190	$0.55761	$0.53249
2001	$0.93791	$0.80624	$0.71615	$0.60332	$0.57614
2002	$1.02318	$0.87953	$0.78126	$0.65816	$0.62852
2003	$1.09423	$0.94061	$0.83551	$0.70387	$0.67216
2004	$1.13686	$0.97725	$0.86806	$0.73129	$0.69835
2005	$1.22213	$1.05055	$0.93317	$0.78614	$0.75073
2006	$1.27897	$1.09941	$0.97657	$0.82271	$0.78565
2007	$1.33581	$1.14827	$1.01997	$0.85927	$0.82056
2008	$1.37845	$1.18492	$1.05253	$0.88669	$0.84675
2009	$1.40687	$1.20935	$1.07423	$0.90498	$0.86421
2010	$1.44950	$1.24600	$1.10678	$0.93240	$0.89040
2011	$1.47792	$1.27043	$1.12848	$0.95068	$0.90786
2012	$1.52055	$1.30708	$1.16103	$0.97811	$0.93405
2013	$1.57740	$1.35594	$1.20444	$1.01467	$0.96896
2014	$1.60582	$1.38037	$1.22614	$1.03295	$0.98642
2015	$1.64845	$1.41702	$1.25869	$1.06038	$1.01261
2016	$1.67687	$1.44145	$1.28039	$1.07866	$1.03007

Year	SC8 Demand Chg ($/therm)	CNG Transport	Iroquois Commodity Charge	Iroquois Demand Chg ($/therm)	Propane Price
1992	$0.0794	$0.0332	$0.01263	$0.0659	$0.6004
1993	$0.0810	$0.0339	$0.01288	$0.0672	$0.5942
1994	$0.0825	$0.0345	$0.01313	$0.0684	$0.5818
1995	$0.0825	$0.0345	$0.01313	$0.0684	$0.5695
1996	$0.0825	$0.0345	$0.01313	$0.0684	$0.5695
1997	$0.0825	$0.0345	$0.01313	$0.0684	$0.5695
1998	$0.0841	$0.0352	$0.01337	$0.0697	$0.5756
1999	$0.0887	$0.0371	$0.01412	$0.0736	$0.5818
2000	$0.0950	$0.0397	$0.01511	$0.0788	$0.5880
2001	$0.1028	$0.0430	$0.01634	$0.0852	$0.6004
2002	$0.1121	$0.0469	$0.01783	$0.0930	$0.6128
2003	$0.1199	$0.0501	$0.01907	$0.0994	$0.6252
2004	$0.1245	$0.0521	$0.01981	$0.1033	$0.6375
2005	$0.1339	$0.0560	$0.02130	$0.1111	$0.6499
2006	$0.1401	$0.0586	$0.02229	$0.1162	$0.6623
2007	$0.1463	$0.0612	$0.02328	$0.1214	$0.6747

TABLE B.2. (contd)

Year	SC8 Demand Chg ($/therm)	CNG Transport	Iroquois Commodity Charge	Iroquois Demand Chg ($/therm)	Propane Price
2008	$0.1510	$0.0631	$0.02402	$0.1253	$0.6809
2009	$0.1541	$0.0644	$0.02452	$0.1278	$0.6809
2010	$0.1588	$0.0664	$0.02526	$0.1317	$0.6871
2011	$0.1619	$0.0677	$0.02576	$0.1343	$0.6994
2012	$0.1666	$0.0697	$0.02650	$0.1382	$0.7118
2013	$0.1728	$0.0723	$0.02749	$0.1433	$0.7242
2014	$0.1759	$0.0736	$0.02798	$0.1459	$0.7366
2015	$0.1806	$0.0755	$0.02873	$0.1498	$0.7490
2016	$0.1837	$0.0768	$0.02922	$0.1524	$0.7613

Year	Electricity $/kWh	Electricity Demand Chg. $/kW	New York State Import Tax	DFSC Gas Winter	DFSC Gas Summer
1992	$0.0506	$5.51	$0.0079	$0.229	$0.215
1993	$0.0506	$5.51	$0.0081	$0.234	$0.220
1994	$0.0511	$5.57	$0.0083	$0.238	$0.224
1995	$0.0496	$5.40	$0.0083	$0.238	$0.224
1996	$0.0486	$5.29	$0.0083	$0.238	$0.224
1997	$0.0480	$5.23	$0.0083	$0.238	$0.224
1998	$0.0475	$5.18	$0.0084	$0.243	$0.228
1999	$0.0470	$5.12	$0.0089	$0.256	$0.241
2000	$0.0475	$5.18	$0.0095	$0.274	$0.258
2001	$0.0475	$5.18	$0.0103	$0.297	$0.279
2002	$0.0475	$5.18	$0.0112	$0.324	$0.304
2003	$0.0475	$5.18	$0.0120	$0.346	$0.325
2004	$0.0475	$5.18	$0.0125	$0.360	$0.338
2005	$0.0480	$5.23	$0.0134	$0.387	$0.363
2006	$0.0480	$5.23	$0.0140	$0.405	$0.380
2007	$0.0486	$5.29	$0.0146	$0.423	$0.397
2008	$0.0486	$5.29	$0.0151	$0.436	$0.410
2009	$0.0480	$5.23	$0.0154	$0.445	$0.418
2010	$0.0486	$5.29	$0.0159	$0.459	$0.431
2011	$0.0491	$5.34	$0.0162	$0.468	$0.439
2012	$0.0491	$5.34	$0.0167	$0.481	$0.452
2013	$0.0491	$5.34	$0.0173	$0.499	$0.469
2014	$0.0496	$5.40	$0.0176	$0.508	$0.477
2015	$0.0496	$5.40	$0.0181	$0.522	$0.490
2016	$0.0496	$5.40	$0.0184	$0.531	$0.498

TABLE B.3. 25-Year Average Delivered Fuel Price Table - Base and Interruption Scenarios

Source:
1 Wellhead-> CNG-> NMPC (SC8)
2 Wellhead-> CNG-> NMPC (SC5-I)
3 Wellhead-> IR-> CNG-> NMPC (SC8)
4 Wellhead-> IR-> CNG-> NMPC (SC5-I)
5 Wellhead-> IR-> NMPC (SC8)
6 Wellhead-> IR-> NMPC (SC5-I)
7 NMPC (SC4)
8 NMPC (SC6)
9 Propane-Air
10 Wellhead-> IR-> Fort Drum
11 DFSC-> NMPC (SC8)
12 DFSC-> NMPC (SC5-I)

Source:	1	2	3	4	5	6
Year	Total	Total	Total	Total	Total	Total
1992	$0.4182	$0.3048	$0.4055	$0.2921	$0.3723	$0.2589
1993	$0.4223	$0.3078	$0.4095	$0.2950	$0.3759	$0.2615
1994	$0.4264	$0.3108	$0.4134	$0.2979	$0.3796	$0.2640
1995	$0.4264	$0.3108	$0.4134	$0.2979	$0.3796	$0.2640
1996	$0.4264	$0.3108	$0.4134	$0.2979	$0.3796	$0.2640
1997	$0.4264	$0.3108	$0.4134	$0.2979	$0.3796	$0.2640
1998	$0.4305	$0.3138	$0.4174	$0.3007	$0.3832	$0.2666
1999	$0.4428	$0.3227	$0.4294	$0.3093	$0.3942	$0.2742
2000	$0.4592	$0.3347	$0.4453	$0.3208	$0.4088	$0.2843
2001	$0.4797	$0.3496	$0.4651	$0.3351	$0.4270	$0.2970
2002	$0.5042	$0.3675	$0.4890	$0.3523	$0.4489	$0.3122
2003	$0.5247	$0.3825	$0.5089	$0.3666	$0.4672	$0.3249
2004	$0.5370	$0.3915	$0.5208	$0.3752	$0.4781	$0.3326
2005	$0.5616	$0.4094	$0.5446	$0.3924	$0.5000	$0.3478
2006	$0.5780	$0.4213	$0.5605	$0.4038	$0.5146	$0.3579
2007	$0.5944	$0.4333	$0.5764	$0.4153	$0.5292	$0.3681
2008	$0.6067	$0.4423	$0.5884	$0.4239	$0.5402	$0.3757
2009	$0.6149	$0.4482	$0.5963	$0.4296	$0.5475	$0.3808
2010	$0.6272	$0.4572	$0.6082	$0.4382	$0.5584	$0.3884
2011	$0.6354	$0.4632	$0.6162	$0.4439	$0.5657	$0.3935
2012	$0.6477	$0.4721	$0.6281	$0.4525	$0.5767	$0.4011
2013	$0.6641	$0.4841	$0.6440	$0.4640	$0.5913	$0.4112
2014	$0.6723	$0.4901	$0.6520	$0.4697	$0.5986	$0.4163
2015	$0.6846	$0.4990	$0.6639	$0.4783	$0.6095	$0.4239
2016	$0.6928	$0.5050	$0.6719	$0.4840	$0.6168	$0.4290

TABLE B.3. (contd)

Source: Year	7 Total	8 Total	9 Total	10 Total	11 Total	12 Total
1992	$0.3181	$0.4619	$0.6004	$0.2201	$0.3841	$0.2708
1993	$0.3213	$0.4664	$0.5942	$0.2223	$0.3879	$0.2734
1994	$0.3244	$0.4709	$0.5818	$0.2245	$0.3917	$0.2761
1995	$0.3244	$0.4709	$0.5695	$0.2245	$0.3917	$0.2761
1996	$0.3244	$0.4709	$0.5695	$0.2245	$0.3917	$0.2761
1997	$0.3244	$0.4709	$0.5695	$0.2245	$0.3917	$0.2761
1998	$0.3275	$0.4754	$0.5756	$0.2266	$0.3954	$0.2787
1999	$0.3369	$0.4890	$0.5818	$0.2331	$0.4067	$0.2867
2000	$0.3493	$0.5071	$0.5880	$0.2417	$0.4218	$0.2973
2001	$0.3649	$0.5298	$0.6004	$0.2525	$0.4406	$0.3106
2002	$0.3836	$0.5569	$0.6128	$0.2655	$0.4632	$0.3265
2003	$0.3992	$0.5796	$0.6252	$0.2762	$0.4820	$0.3398
2004	$0.4086	$0.5932	$0.6375	$0.2827	$0.4933	$0.3477
2005	$0.4273	$0.6203	$0.6499	$0.2957	$0.5159	$0.3637
2006	$0.4398	$0.6384	$0.6623	$0.3043	$0.5310	$0.3743
2007	$0.4523	$0.6566	$0.6747	$0.3129	$0.5461	$0.3849
2008	$0.4616	$0.6701	$0.6809	$0.3194	$0.5574	$0.3929
2009	$0.4678	$0.6792	$0.6809	$0.3237	$0.5649	$0.3982
2010	$0.4772	$0.6928	$0.6871	$0.3302	$0.5762	$0.4061
2011	$0.4834	$0.7018	$0.6994	$0.3345	$0.5837	$0.4114
2012	$0.4928	$0.7154	$0.7118	$0.3410	$0.5950	$0.4194
2013	$0.5053	$0.7335	$0.7242	$0.3496	$0.6101	$0.4300
2014	$0.5115	$0.7426	$0.7366	$0.3539	$0.6176	$0.4353
2015	$0.5209	$0.7562	$0.7490	$0.3604	$0.6289	$0.4433
2016	$0.5271	$0.7652	$0.7613	$0.3647	$0.6364	$0.4486

TABLE B.4. 25-Year Average Delivered Fuel Price Table - High Gas Price Scenario

Source:
1 Wellhead-> CNG-> NMPC (SC8)
2 Wellhead-> CNG-> NMPC (SC5-I)
3 Wellhead-> IR-> CNG-> NMPC (SC8)
4 Wellhead-> IR-> CNG-> NMPC (SC5-I)
5 Wellhead-> IR-> NMPC (SC8)
6 Wellhead-> IR-> NMPC (SC5-I)
7 NMPC (SC4)
8 NMPC (SC6)
9 Propane-Air
10 Wellhead-> IR-> Fort Drum
11 DFSC-> NMPC (SC8)
12 DFSC-> NMPC (SC5-I)

Source:	1	2	3	4	5	6
Year	Total	Total	Total	Total	Total	Total
1992	$0.4182	$0.3048	$0.4055	$0.2921	$0.3723	$0.2589
1993	$0.4264	$0.3108	$0.4134	$0.2979	$0.3796	$0.2640
1994	$0.4346	$0.3167	$0.4214	$0.3036	$0.3869	$0.2691
1995	$0.4346	$0.3167	$0.4214	$0.3036	$0.3869	$0.2691
1996	$0.4346	$0.3167	$0.4214	$0.3036	$0.3869	$0.2691
1997	$0.4346	$0.3167	$0.4214	$0.3036	$0.3869	$0.2691
1998	$0.4428	$0.3227	$0.4294	$0.3093	$0.3942	$0.2742
1999	$0.4674	$0.3407	$0.4532	$0.3265	$0.4161	$0.2894
2000	$0.5001	$0.3646	$0.4850	$0.3494	$0.4453	$0.3097
2001	$0.5411	$0.3944	$0.5248	$0.3781	$0.4818	$0.3351
2002	$0.5903	$0.4303	$0.5725	$0.4124	$0.5256	$0.3656
2003	$0.6313	$0.4602	$0.6122	$0.4411	$0.5621	$0.3909
2004	$0.6559	$0.4781	$0.6361	$0.4583	$0.5840	$0.4062
2005	$0.7051	$0.5140	$0.6838	$0.4926	$0.6278	$0.4366
2006	$0.7379	$0.5379	$0.7156	$0.5155	$0.6570	$0.4569
2007	$0.7707	$0.5618	$0.7474	$0.5384	$0.6862	$0.4773
2008	$0.7953	$0.5797	$0.7712	$0.5556	$0.7081	$0.4925
2009	$0.8117	$0.5917	$0.7871	$0.5671	$0.7227	$0.5026
2010	$0.8363	$0.6096	$0.8110	$0.5843	$0.7446	$0.5179
2011	$0.8527	$0.6215	$0.8269	$0.5957	$0.7592	$0.5280
2012	$0.8773	$0.6395	$0.8508	$0.6129	$0.7811	$0.5433
2013	$0.9101	$0.6634	$0.8826	$0.6358	$0.8103	$0.5636
2014	$0.9265	$0.6753	$0.8985	$0.6473	$0.8249	$0.5737
2015	$0.9511	$0.6933	$0.9223	$0.6645	$0.8468	$0.5890
2016	$0.9675	$0.7052	$0.9382	$0.6759	$0.8614	$0.5991

TABLE B.4. (contd)

Source: Year	7 Total	8 Total	9 Total	10 Total	11 Total	12 Total
1992	$0.3181	$0.4619	$0.6004	$0.2201	$0.3841	$0.2708
1993	$0.3244	$0.4709	$0.5942	$0.2245	$0.3917	$0.2761
1994	$0.3306	$0.4800	$0.5818	$0.2288	$0.3992	$0.2814
1995	$0.3306	$0.4800	$0.5695	$0.2288	$0.3992	$0.2814
1996	$0.3306	$0.4800	$0.5695	$0.2288	$0.3992	$0.2814
1997	$0.3306	$0.4800	$0.5695	$0.2288	$0.3992	$0.2814
1998	$0.3369	$0.4890	$0.5756	$0.2331	$0.4067	$0.2867
1999	$0.3556	$0.5162	$0.5818	$0.2460	$0.4293	$0.3026
2000	$0.3805	$0.5524	$0.5880	$0.2633	$0.4594	$0.3238
2001	$0.4117	$0.5977	$0.6004	$0.2849	$0.4971	$0.3504
2002	$0.4491	$0.6520	$0.6128	$0.3108	$0.5423	$0.3822
2003	$0.4803	$0.6973	$0.6252	$0.3324	$0.5799	$0.4088
2004	$0.4990	$0.7245	$0.6375	$0.3453	$0.6025	$0.4247
2005	$0.5365	$0.7788	$0.6499	$0.3712	$0.6477	$0.4566
2006	$0.5614	$0.8150	$0.6623	$0.3885	$0.6779	$0.4778
2007	$0.5864	$0.8513	$0.6747	$0.4057	$0.7080	$0.4990
2008	$0.6051	$0.8784	$0.6809	$0.4187	$0.7306	$0.5150
2009	$0.6176	$0.8965	$0.6809	$0.4273	$0.7456	$0.5256
2010	$0.6363	$0.9237	$0.6871	$0.4403	$0.7682	$0.5415
2011	$0.6488	$0.9418	$0.6994	$0.4489	$0.7833	$0.5521
2012	$0.6675	$0.9690	$0.7118	$0.4619	$0.8059	$0.5681
2013	$0.6924	$1.0052	$0.7242	$0.4791	$0.8360	$0.5893
2014	$0.7049	$1.0233	$0.7366	$0.4877	$0.8511	$0.5999
2015	$0.7236	$1.0505	$0.7490	$0.5007	$0.8737	$0.6158
2016	$0.7361	$1.0686	$0.7613	$0.5093	$0.8888	$0.6265

APPENDIX C

LIFE-CYCLE COST METHODOLOGY

APPENDIX C

LIFE-CYCLE COST METHODOLOGY

As discussed in the main report, each of the supply components was combined to create complete supply strategies. The demand forecast for Fort Drum was used to evaluate the cost and capacity constraints of each strategy. The life-cycle cost was calculated for each supply strategy, and then those figures were compared to determine which supply mix would be the optimal one for Fort Drum. For the analysis calculations, the discount rate of 4.6% and the 25-year period were chosen following the federal guidelines established in 10 CFR, Part 436, Subpart A (U.S. DOC 1991, p. iii).

The life-cycle cost and net present value cost for each strategy were calculated as shown in Equations C.1 and C.2:

$$LCC = PV(EC) + PV(IC) + PV(OM) \tag{C.1}$$

$$PV = \sum_{t=1}^{25} \frac{C_t}{(1 + i)^t} \tag{C.2}$$

where LCC = life-cycle cost

PV(EC) = net present value of energy cost

PV(IC) = net present value of investment cost

PV (OM) = net present value of operation and maintenance cost

PV = net present value

C = cost in year t

t = year

i = discount rate (4.6%).

The net present value of investment, used in the comparison tables in the summary, was calculated by subtracting the existing supply life-cycle cost from each of the alternative strategy life-cycle costs.

C.1 GAS PURCHASE AT WELLHEAD

Calculations for this component were broken down into two groups. The first, broker costs, was used to calculate the cost of purchasing gas through a broker. For the calculations, the origin of the natural gas did not matter as the methodology was the same. The second group of calculations was used to estimate the costs involved with the purchase of natural gas from NMPC under the SC4 rate.

C.1.1 Broker Costs

Broker costs consisted of energy costs. The annual energy cost was calculated using Equation (C.3).[a]

$$C_B = (G + T + A) * O \tag{C.3}$$

where C_B = broker cost ($ per year)

G = gas price ($ per therm)

T = transportation price ($ per therm)

A = adjustment factor ($0.0099 per therm)

O = gas ordered from broker per year.

An annual cost stream was generated, from which the net present value was calculated.

(a) Current gas purchasing contract with Hudson Bay Natural Gas Company for supply of natural gas to Fort Drum, Section B, P. B-1.

C.1.2 DFSC Costs

DFSC costs are comprised of energy costs which were calculated using Equation (C.4).

$$C_D = P * G \tag{C.4}$$

where C_D = DFSC cost ($ per year)

P = price of gas ($ per therm)

G = DFSC gas used (therms per year).

C.1.3 NMPC SC4 Costs

The SC4 rate is comprised of energy costs which were calculated using Equation (C.5).[a]

$$C_4 = MC + P * G \tag{C.5}$$

where C_4 = cost of SC4 per year

MC = minimum monthly charge ($825 per month)

P = price of gas ($ per therm)

G = gas used (therms per year).

These costs created an annual cost stream, from which the net present value of the energy costs was calculated.

Two cost streams were calculated for this rate. The first assumed that NMPC was able to deliver all gas required by Fort Drum. The second assumed that NMPC was unable to deliver all gas required causing Fort Drum to resort

(a) Personal communication, Dennis Bartlett, Gas Transportation Specialist, Niagara Mohawk Power Corp. March 4, 1992. 9:00 a.m.

to the propane-air station for the remainder of its fuel requirements. In the second case, then, the amount of gas used under SC4 was less than the first.

C.2 TRANSPORT TO PIPELINE

Costs for this component were included in the cost calculations for the first component. For broker cost calculations, the transportation cost is included in the transportation price. For DFSC and NMPC SC4 calculations, the transportation cost is incorporated into the price charged for natural gas.

C.3 PIPELINE TRANSPORT TO CITY-GATE

While the options under this component dealt primarily with transportation through the Iroquois pipeline, there was one option which assumed gas transportation on the CNG pipeline. The cost calculations for that option are included in the transportation price charged by the broker since the broker arranges it. Although the broker would also arrange transportation through the Iroquois pipeline, the Iroquois charges were calculated separately from the broker transportation price, as no historical data was available, and therefore required more detailed calculations than that of CNG transportation.

C.3.1 Iroquois to CNG to NMPC Transportation

At present, the only way in which natural gas can be transported to Fort Drum from the Iroquois pipeline is via CNG and NMPC. Transportation charges were computed for this component using Equation (C.6).

$$C_{IC} = D_I * D_D + (CI + C + P_C) * G \qquad (C.6)$$

where C_{IC} = transportation costs through Iroquois and CNG ($ per year)

D_I = Iroquois demand charge ($ per therm)

D_D = daily demand nomination (therms per year)

CI = Iroquois commodity charge ($ per therm)

C = CNG charge ($ per therm)

P_C = price of Canadian gas ($ per therm)

G = volume of gas transported (therms per year).

These charges formed an annual cost stream from which the net present value was calculated. The CNG transportation charge was derived from Fort Drum's November 1991 billing statement from Hudson Bay Natural Gas Corporation, and was escalated according to DOE escalation rates. Canadian gas prices were used because it was assumed that gas transported through the Iroquois pipeline would originate in Canada. Because the interruptions assumed in the analysis dealt only with an NMPC gas interruption, it was assumed that no interruption would take place under this component.

C.3.2 Iroquois to NMPC Transportation

While it is currently impossible to ship natural gas through Iroquois without also shipping through CNG, the pipeline from Iroquois to NMPC should be opening in 1994. It will then be possible for Fort Drum to purchase gas and then ship it directly from Iroquois to NMPC. The transportation cost for this component was calculated using Equation (C.7).

$$C_I = D_I * D_D + (CI + P_C) * G \tag{C.7}$$

where C_I = transportation cost through Iroquois per year

D_I = Iroquois demand charge ($ per therm)

D_D = daily demand nomination (therms per year)

CI = Iroquois commodity charge ($ per therm)

P_C = price of Canadian gas ($ per therm)

G = volume of gas transported (therms per year).

These costs formed an annual cost stream from which the net present value was calculated. Because the interruption under the Interruption scenario assumed in the analysis dealt only with an NMPC gas interruption, it was assumed that an interruption would not affect costs under this component.

C.3.3 Iroquois to Fort Drum Pipeline

The pipeline option actually incorporates two components, transport to the city-gate and transport from city-gate to burner-tip, although the city-gate is avoided because the pipeline bypasses the local distribution company (NMPC). This option is composed of energy, capital, and O&M costs.

Energy Costs

The energy cost for the pipeline component was computed using Equation (C.8).

$$C_E = D_I * D_D + (CI + P_C + t) * G \tag{C.8}$$

where C_E = energy cost per year

D_I = Iroquois demand charge ($ per therm)

D_D = daily demand nomination (therms per year)

CI = Iroquois commodity charge ($ per therm)

P_C = price of Canadian gas ($ per therm)

t = New York State import tax ($ per therm)

G = volume of gas (therms per year).

These costs formed an annual cost stream, from which the net present value was calculated. The transportation charge is composed of demand and commodity charges on the Iroquois pipeline. The demand charge acts as a reservation fee to ensure firm transportation on the pipeline, and the commodity charge is the rate charged on the transportation of each therm. Canadian gas prices were used for this component because the Iroquois pipeline originates in Canada.

Capital Cost

The capital cost was computed using Equation (C.9).

$$C_C = P * D \qquad (C.9)$$

where C_C = capital cost of pipeline

P = estimated cost per mile of pipeline (\$ per mile)

D = miles of pipeline required.

Operation and Maintenance Costs

The O&M costs were the estimated costs for O&M of the pipeline once it was built. They formed an annual cost stream, from which the net present value was calculated.

C.4 TRANSPORTATION FROM CITY-GATE TO BURNER-TIP

Costs under this component are composed of the NMPC charges for transporting customer-owned gas to the customer. The costs of piping gas from the Iroquois pipeline directly to Fort Drum were included in the pipeline costs above.

C.4.1 NMPC SC8 Costs

The NMPC SC8 rate component does not involve construction or operation. An annual energy cost was calculated using Equation (C.10).[a]

$$C_8 = T * G_D + (D_D * D1 + D_A * D2) + t * G_B \qquad (C.10)$$

where C_8 = cost of SC8 per year

T = transportation price (\$ per therm)

G_D = gas delivered under SC8 rate

D_D = daily demand nomination (therms per year)

(a) Personal communication, Dennis Bartlett, Gas Transportation Specialist, Niagara Mohawk Power Corp. March 4, 1992. 9:00 a.m.

D_A = annual demand nomination (therms per year)

D1 = daily demand charge ($0.70 per therm initially)

D2 = annual demand charge ($0.03 per therm initially)

t = New York State import tax ($0.0079 per therm initially)

G_B = gas delivered from broker or DFSC (therms per year).

The estimated annual gas demand was used as the annual demand nomination. The daily demand nomination was calculated by using the ratio of estimated annual demand over current annual demand and multiplying by current daily demand. The prices used for demand charges were approximate monthly charges,[a] and were escalated using the DOE escalation rate. The New York State import tax was derived from Fort Drum's November 1991 NMPC billing statement and was escalated using the DOE escalation rate.

C.4.2 NMPC SC5-I Costs

The energy costs associated with this rate were calculated using Equation (C.11).[b]

$$C_5 = T * G_D + t * G_B \tag{C.11}$$

where C_5 = cost of SC5-I per year

T = transportation price ($ per therm)

G_D = gas delivered under SC5-I rate (therms per year)

t = New York State import tax ($0.0079 per therm initially)

G_B = gas delivered from broker or DFSC (therms per year).

(a) Personal Communication, Dennis Bartlett, Gas Transportation Specialist, Niagara Mohawk Power Corporation. March 4, 1992. 9:00 a.m.
(b) Personal communication, Janice Bailey, Supervisor, Customer Transportation, Niagara Mohawk Power Corp. February 21, 1992.

These annual energy costs formed a cost stream. The net present value was calculated from the cost stream to yield the present value of the energy costs associated with this component.

C.5 SUPPLEMENTAL FUEL SERVICE

Supplemental fuel charges are divided into the costs associated with a propane-air station and the charges levied by NMPC under its SC6 supplemental gas service rate.

C.5.1 Propane-Air Station

The propane-air station component involves energy costs, capital (construction) costs, and operation and maintenance costs.

Energy Costs

Energy costs for the propane-air station were calculated using Equations (C.12) and (C.13).

$$C_P = H * C_E + D_E + F * G_F \qquad (C.12)$$

and

$$H = Th * PC * a \qquad (C.13)$$

where C_P = cost of propane-air plant per year

H = hours of operation

C_E = cost of electricity per kilowatt-hour ($ per kWh)

D_E = electricity demand charge ($ per kW)

F = fuel cost ($ per gallon)

G_F = gallons of fuel

Th = therms needed for total annual interruptions

PC = plant capacity (therms per hour)

a = average operating capacity percentage (0.60).

It was assumed that the plant would operate, on average, at 60% capacity during a 24-hour day.[a]

Three cost streams were calculated for this component. The first assumed that the propane-air station would be used after the broker could not deliver the monthly amount required. The second assumed that the propane-air station would be used after the DFSC could not deliver the monthly amount required, and the third assumed that the propane-air station was used during a gas interruption on the part of NMPC.

Capital Costs

The capital cost was provided by Combustion Services.[b]

Operation and Maintenance Costs

Operation and Maintenance (O&M) costs can be broken into two separate cost flows: fixed and variable. Fixed O&M costs included scheduled maintenance and station testing days. Following the direction of the Fort Meade study, it was assumed that there would be 5 scheduled maintenance days per year and 2 days for facility testing during the summer season, and that labor costs were set at $50 per hour.

Variable O&M costs varied with each supply strategy. In general, each transportation interruption was assumed to last 2 to 3 days. Following the direction of the Fort Meade study again, it was assumed that each interruption would require 8 hours for startup and shutdown of the plant. For every 10 interruptions an allowance was made for 1 unscheduled maintenance day, and 1 scheduled maintenance day was added.

(a) Personal Communication, Plyler McMannus, Army Corps of Engineers, Huntsville Division. May 20, 1992. 10:30 a.m.
(b) Personal Communication, Ray Self, Combustion Services Inc. May 28, 1992. 8:00 a.m.

Under the Interruption scenario, it was assumed that there were six NMPC gas supply interruptions for a total of 264 hours (11 days), causing the addition of 1 unscheduled maintenance day, and 1 scheduled maintenance day was added.

Under the DFSC interruptible strategies in the Base Case and High Gas Price scenarios, it was assumed that gas supply would be interrupted prior to reaching NMPC for a total of 21 days, requiring the purchase of either propane or NMPC SC6 gas.

For strategy 5, interruptible transportation using the propane-air station as the supplemental gas source, it was assumed that the station would need to operate a total of 27 days under the New Fort scenarios; and would operate 81 days under the Entire Fort scenarios.

These costs formed the O&M cost stream, from which the present value was calculated to determine the present value of O&M costs for the life-cycle calculation.

C.5.2 NMPC SC6 Costs

As with broker costs, the costs faced under NMPC rate SC6 were comprised only of energy costs. A tiered payment scale was used to determine the price charged for SC6 service. The number of therms bought and transported under SC6 are charged as follows:[a]

First 3 therms or less	$5.81
Next 37 therms, per therm	$0.72475
Next 240 therms, per therm	$0.62300
Next 6,920 therms, per therm	$0.55339
Next 92,800 therms, per therm	$0.46620
Over 100,000 therms, per therm	$0.44520

These rates were escalated according to the DOE escalation rates for commercial natural gas and were assumed to include transportation. From these

(a) Niagara Mohawk Power Corporation, Energy Decisions: Explanation of Service Classifications, October 1991.

rates, two cost streams were generated. The first assumed that all supplemental gas required was supplied under the SC6 classification. The second assumed that a gas interruption on the part of NMPC occurred, affecting only those customers who have dual-fuel supply systems. The interruption lessened the amount of SC6 gas taken because the Fort would be required to switch over to its back-up system.

APPENDIX D

DETAILED RESULTS

APPENDIX D

DETAILED RESULTS

Each of the components described in the main report was combined in different ways to form the supply strategies that made up the analysis. The strategies were analyzed under the six different scenarios: New Fort, New Fort with higher gas prices, New Fort with NMPC gas interruptions, Entire Fort, Entire Fort with higher gas prices, and Entire Fort with NMPC gas interruptions.

D.1 EXISTING SUPPLY

The existing supply strategy was calculated by adding together the broker, SC8, and SC6 components. These component costs generated an annual energy cost stream for the strategy, from which the net present value was calculated. Because these components were comprised only of energy costs, the life-cycle cost for this strategy was equivalent to the present value of the energy cost stream generated. The scenarios are specified in Table D.1.

Table D.2 contains the results for each of the scenarios studied under the existing supply strategy. This strategy did not have interruption scenarios calculated because of the way in which NMPC customers are taken off the supply line. In the case of a gas shortage, NMPC would first curtail its own

TABLE D.1. Scenarios

Scenario	Demand Scenario	Price Scenario	Interruption Scenario
1	New Fort	Base	Base
2	New Fort	High	Base
3	New Fort	Base	Inter
4	Entire Fort	Base	Base
5	Entire Fort	High	Base
6	Entire Fort	Base	Inter

TABLE D.2. Existing Supply Strategy (Strategy 0) (1992 $ thousands)

Scenario	Annual Energy Cost ($)	Annual Energy Cost Reduction Over Base ($)	Present Value of Energy Costs ($)	Capital Cost of Strategy ($)
1	$1,283	$0	$22,906	$0
2	$1,283	$0	$26,983	$0
3	$1,283	$0	$22,906	$0
4	$3,198	$0	$57,166	$0
5	$3,198	$0	$67,398	$0
6	$3,198	$0	$57,166	$0

Scenario	Average Annual O&M ($)	Present Value of Annual O&M ($)	Life-Cycle Cost ($)	Net Present Value of Strategy ($)
1	$0	$0	$22,906	$0
2	$0	$0	$26,983	$0
3	$0	$0	$22,906	$0
4	$0	$0	$57,166	$0
5	$0	$0	$67,398	$0
6	$0	$0	$57,166	$0

use, then interruptible customers falling in the SC4 and SC5-I classifications would be asked to switch to their backup fuel supply, and then SC8 customers would be interrupted.[a] Since the SC8 customers are further down on the list, and because NMPC has had no interruptions in the past, it was assumed that an interruption on the part of NMPC would not affect Fort Drum under the SC8 classification. The base numbers for the New and Entire Fort were used instead as a comparison for the other strategies explored.

D.2 SWITCH TO NMPC RATE SC4

The SC4 strategy (Strategy 1) was calculated by adding the SC4 component with the cost of the initial filling of the propane tanks for the base and high gas price scenarios. For the interruption scenarios, where it was assumed that there was an NMPC gas interruption, the SC4 component minus the

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(a) Personal Communication, Janice Bailey, Supervisor, Customer Transportation, Niagara Mohawk Power Corporation. February 21, 1992.

interrupted amount was added to the cost stream of running the propane-air station for the interrupted amount.

Table D.3 contains the results for each of the scenarios studied under the SC4 supply strategy. Because the assumed interruption was an NMPC gas interruption, and because SC4 and SC5-I customers are the first customers to be interrupted, the costs under this strategy were affected.

TABLE D.3. Rate (Strategy 1) (1992 $ thousands)

Scenario	Annual Energy Cost ($)	Annual Energy Cost Reduction Over Base ($)	Present Value of Energy Costs ($)	Capital Cost of Strategy ($)
1	$1,091	$192	$16,497	$950
2	$1,091	$192	$19,417	$950
3	$1,136	$147	$17,029	$950
4	$2,434	$764	$39,033	$1,393
5	$2,434	$764	$46,005	$1,393
6	$2,514	$684	$40,000	$1,393

Scenario	Average Annual O&M ($)	Present Value of Annual O&M ($)	Life-Cycle Cost ($)	Net Present Value of Strategy ($)
1	$3	$41	$17,446	$5,461
2	$3	$41	$20,366	$6,616
3	$6	$88	$18,025	$4,882
4	$3	$41	$40,406	$16,761
5	$3	$41	$47,378	$20,020
6	$6	$88	$41,420	$15,747

D.3 SWITCH TO NMPC RATE SC5-I USING IROQUOIS TRANSPORTED GAS

Two strategies actually fall under this category because the analysis included both the Iroquois-CNG to NMPC and Iroquois to NMPC pipelines. After speaking with Bob Phillips of CNG and Chris Bosco of Iroquois, it was assumed that, barring unforeseen circumstances, gas shipped through Iroquois should not face a transportation bottleneck. It was therefore assumed that Fort Drum could meet all of its gas requirements through the broker because no transportation interruption would occur. Because these strategies do not require supplemental gas, an NMPC gas interruption would not affect them.

D.3.1 Transport via Iroquois

The costs for this strategy were calculated by adding the Iroquois component with the SC5-I component, and then adding the cost of initially filling the propane tanks. The results of the analysis for this strategy are contained in Table D.4 for each of the scenarios.

D.3.2 Transport via Iroquois and CNG

The costs for this strategy were calculated by adding the Iroquois-CNG component with the SC5-I component, and then adding in the cost of fuel required to initially fill the propane tanks. Table D.5 contains the results for this strategy under the different scenarios, with the interruption scenarios being equal to the base scenarios because the NMPC gas interruption does not affect this strategy.

TABLE D.4. Iroquois SC5-I with Propane Air (Strategy 2) (1992 $ thousands)

Scenario	Annual Energy Cost ($)	Annual Energy Cost Reduction Over Base ($)	Present Value of Energy Costs ($)	Capital Cost of Strategy ($)
1	$930	$353	$13,542	$950
2	$930	$353	$15,881	$950
3	$930	$353	$13,542	$950
4	$2,060	$1,138	$32,146	$1,393
5	$2,060	$1,138	$37,727	$1,393
6	$2,060	$1,138	$32,146	$1,393

Scenario	Average Annual O&M ($)	Present Value of Annual O&M ($)	Life-Cycle Cost ($)	Net Present Value of Strategy ($)
1	$3	$41	$14,491	$8,416
2	$3	$41	$16,831	$10,152
3	$3	$41	$14,491	$8,416
4	$3	$41	$33,519	$23,647
5	$3	$41	$39,099	$28,298
6	$3	$41	$33,519	$23,647

TABLE D.5. SC5-I with Propane Air (Strategy 3) (1992 $ thousands)

Scenario	Annual Energy Cost ($)	Annual Energy Cost Reduction Over Base ($)	Present Value of Energy Costs ($)	Capital Cost of Strategy ($)
1	$1,022	$261	$15,204	$950
2	$1,022	$261	$17,844	$950
3	$1,022	$261	$15,204	$950
4	$2,281	$917	$36,112	$1,393
5	$2,281	$917	$42,408	$1,393
6	$2,281	$917	$36,112	$1,393

Scenario	Average Annual O&M ($)	Present Value of Annual O&M ($)	Life-Cycle Cost ($)	Net Present Value of Strategy ($)
1	$3	$41	$16,153	$6,754
2	$3	$41	$18,793	$8,190
3	$3	$41	$16,153	$6,754
4	$3	$41	$37,484	$19,682
5	$3	$41	$43,781	$23,617
6	$3	$41	$37,484	$19,682

D.4 SWITCH TO NMPC RATE SC5-I USING BROKER

The SC5-I rate using a broker contains two separate strategies. The first assumed that the Fort would take SC6 supplemental gas when the broker was unable to deliver the required amount of natural gas. The second assumed that when the broker could not deliver the entire amount of gas required, the Fort would switch to the propane-air station to meet its demand.

D.4.1 NMPC SC6 as Supplemental

The costs for this strategy under the base and high gas scenarios were calculated by adding the broker, SC5-I, and SC6 components. Because an interruption of NMPC gas would affect this strategy, the interruption scenarios were different than those of the base cases. For the interruption scenarios, this strategy was calculated by adding the broker, SC5-I, and SC6 components adjusted for less gas along with the propane-air requirements in the interruption case. The results for this strategy are contained in Table D.6.

TABLE D.6. NMPC SC5-I with SC6 (Strategy 4) (1992 $ thousands)

Scenario	Annual Energy Cost ($)	Annual Energy Cost Reduction Over Base ($)	Present Value of Energy Costs ($)	Capital Cost of Strategy ($)
1	$1,166	$117	$17,790	$950
2	$1,166	$117	$20,912	$950
3	$1,194	$90	$18,028	$950
4	$2,828	$370	$46,011	$1,393
5	$2,828	$370	$54,183	$1,393
6	$2,879	$319	$46,458	$1,393

Scenario	Average Annual O&M ($)	Present Value of Annual O&M ($)	Life-Cycle Cost ($)	Net Present Value of Strategy ($)
1	$3	$41	$18,739	$4,167
2	$3	$41	$21,861	$5,121
3	$6	$88	$19,024	$3,882
4	$3	$41	$47,384	$9,783
5	$3	$41	$55,556	$11,842
6	$6	$88	$47,878	$9,288

D.4.2 Propane-Air Station as Supplemental

Costs for this strategy were calculated by adding the broker, SC5-I, and propane-air components. Strategy was unaffected by an interruption because no NMPC gas was assumed to have been taken. The interruption scenarios were therefore the same as those of the base cases. Table D.7 contains the results of this strategy under each of the scenarios studied.

TABLE D.7. NMPC SC5-I with Propane Air (Strategy 5) (1992 $ thousands)

Scenario	Annual Energy Cost ($)	Annual Energy Cost Reduction Over Base ($)	Present Value of Energy Costs ($)	Capital Cost of Strategy ($)
1	$1,262	$21	$18,491	$950
2	$1,262	$21	$20,658	$950
3	$1,262	$21	$18,491	$950
4	$3,388	($190)	$50,505	$1,393
5	$3,388	($190)	$53,602	$1,393
6	$3,388	($190)	$50,505	$1,393

Scenario	Average Annual O&M ($)	Present Value of Annual O&M ($)	Life-Cycle Cost ($)	Net Present Value of Strategy ($)
1	$9	$129	$19,528	$3,379
2	$9	$129	$21,695	$5,288
3	$9	$129	$19,528	$3,379
4	$20	$299	$52,136	$5,030
5	$20	$299	$55,233	$12,164
6	$20	$299	$52,136	$5,030

D.5 MAINTAIN SC8 RATE USING IROQUOIS TRANSPORTED GAS

It would also be possible to maintain the SC8 rate under NMPC, but transport the gas through the Iroquois pipeline instead of from the supplier through CNG. There are two strategies included in this possibility. The first allows for direct transportation from Iroquois to NMPC, which will be possible once the pipeline is constructed. The second allows for transportation from Iroquois to NMPC via CNG, which is currently possible. As with the similar strategies under SC5-I with transportation through Iroquois, it was assumed that there would be enough capacity to meet the needs of the Fort without having to rely on supplemental gas. Therefore, the NMPC gas interruption does not affect these strategies.

D.5.1 Transport via Iroquois

Costs for this strategy were calculated by adding the Iroquois component with the SC8 component. Table D.8 contains the results of this strategy under each scenario.

TABLE D.8. SC8 (Strategy 6) (1992 $ thousands)

Scenario	Annual Energy Cost ($)	Annual Energy Cost Reduction Over Base ($)	Present Value of Energy Costs ($)	Capital Cost of Strategy ($)
1	$1,069	$214	$19,047	$0
2	$1,069	$214	$22,411	$0
3	$1,069	$214	$19,047	$0
4	$2,548	$650	$45,421	$0
5	$2,548	$650	$53,443	$0
6	$2,548	$650	$45,421	$0

Scenario	Average Annual O&M ($)	Present Value of Annual O&M ($)	Life-Cycle Cost ($)	Net Present Value of Strategy ($)
1	$0	$0	$19,047	$3,859
2	$0	$0	$22,411	$4,571
3	$0	$0	$19,047	$3,859
4	$0	$0	$45,421	$11,746
5	$0	$0	$53,443	$13,955
6	$0	$0	$45,421	$11,746

D.5.2 Transport via Iroquois and CNG

The costs for this strategy were calculated by adding the Iroquois-CNG component with the SC8 component. The results of this strategy are contained in Table D.9 for each of the scenarios.

TABLE D.9. Iroquois-CNG SC8 (Strategy 7) (1992 $ thousands)

Scenario	Annual Energy Cost ($)	Annual Energy Cost Reduction Over Base ($)	Present Value of Energy Costs ($)	Capital Cost of Strategy ($)
1	$1,161	$122	$20,709	$0
2	$1,161	$122	$24,374	$0
3	$1,161	$122	$20,709	$0
4	$2,770	$428	$49,386	$0
5	$2,770	$428	$58,124	$0
6	$2,770	$428	$49,386	$0

Scenario	Average Annual O&M ($)	Present Value of Annual O&M ($)	Life-Cycle Cost ($)	Net Present Value of Strategy ($)
1	$0	$0	$20,709	$2,197
2	$0	$0	$24,374	$2,609
3	$0	$0	$20,709	$2,197
4	$0	$0	$49,386	$7,780
5	$0	$0	$58,124	$9,274
6	$0	$0	$49,386	$7,780

D.6 PIPELINE DIRECT FROM IROQUOIS TO FORT DRUM

This strategy's costs were taken directly from the pipeline component. Because no transportation problems were foreseen on the Iroquois pipeline, and because NMPC was completely bypassed for this strategy, an interruption in NMPC gas would not affect the results. The results of this strategy are contained in Table D.10 for each of the scenarios.

TABLE D.10. Pipeline (Strategy 8) (1992 $ thousands)

Scenario	Annual Energy Cost ($)	Annual Energy Cost Reduction Over Base ($)	Present Value of Energy Costs ($)	Capital Cost of Strategy ($)
1	$615	$668	$11,021	$13,700
2	$615	$668	$13,010	$13,700
3	$615	$668	$11,021	$13,700
4	$1,468	$1,730	$26,286	$13,700
5	$1,468	$1,730	$31,030	$13,700
6	$1,468	$1,730	$26,286	$13,700

Scenario	Average Annual O&M ($)	Present Value of Annual O&M ($)	Life-Cycle Cost ($)	Net Present Value of Strategy ($)
1	$14	$201	$24,320	($1,414)
2	$14	$201	$26,309	$673
3	$14	$201	$24,320	($1,414)
4	$14	$201	$39,585	$17,582
5	$14	$201	$44,329	$23,069
6	$14	$201	$39,585	$17,582

D.7 MAINTAIN NMPC SC8 RATE USING DFSC SUPPLIED GAS

This strategy's costs were calculated by adding the DFSC, SC8, and SC6 component costs. Because SC8 customers are not the first to be interrupted, it was assumed that an NMPC interruption would not affect the outcome of this strategy. Table D.11 contains the results of this strategy under each scenario.

TABLE D.11. SC8 (Strategy 9) (1992 $ thousands)

Scenario	Annual Energy Cost ($)	Annual Energy Cost Reduction Over Base ($)	Present Value of Energy Costs ($)	Capital Cost of Strategy ($)
1	$1,123	$160	$20,051	$0
2	$1,123	$160	$23,617	$0
3	$1,123	$160	$20,051	$0
4	$2,643	$555	$47,340	$0
5	$2,646	$552	$55,944	$0
6	$2,643	$555	$47,340	$0

Scenario	Average Annual O&M ($)	Present Value of Annual O&M ($)	Life-Cycle Cost ($)	Net Present Value of Strategy ($)
1	$0	$0	$20,051	$2,856
2	$0	$0	$23,617	$3,366
3	$0	$0	$20,051	$2,856
4	$0	$0	$47,340	$9,827
5	$0	$0	$55,944	$11,453
6	$0	$0	$47,340	$4,796

D.8 SWITCH TO NMPC SC5-I RATE USING DFSC-SUPPLIED GAS

The Sc5-I rate using DFSC-supplied gas contains two separate strategies. first assumed that when the DFSC could not deliver the entire amount of natural gas required, the Fort would switch to the propane-air station. The second assumed that the Fort would take SC6 supplemental gas to meet its demand when the DFSC was not able to deliver the required amount of natural gas.

D.8.1 Propane-Air Station as Supplemental

The costs for this strategy under the base and high gas scenarios were calculated by adding the DFSC, SC5-I, and propane-air components. Because it was assumed that the DFSC could deliver all gas required from February through October, an NMPC interruption did affect this strategy since an interruption of 24 hours was assumed for the month of October. For the interruption scenarios, this strategy was calculated by adding the DFSC, SC5-I, and propane-air components adjusted for the decreased amount of gas delivered under SC5-I and the increased amount of gas under the propane-air component. The results for this strategy are contained in Table D.12.

TABLE D.12. SC5-I with Propane Air (Strategy 10) (1992 $ thousands)

Scenario	Annual Energy Cost ($)	Annual Energy Cost Reduction Over Base ($)	Present Value of Energy Costs ($)	Capital Cost of Strategy ($)
1	$930	$353	$14,998	$950
2	$1,039	$244	$17,284	$950
3	$1,047	$236	$14,976	$950
4	$2,259	$939	$35,051	$1,393
5	$2,259	$939	$40,465	$1,393
6	$2,274	$924	$34,674	$1,393

Scenario	Average Annual O&M ($)	Present Value of Annual O&M ($)	Life-Cycle Cost ($)	Net Present Value of Strategy ($)
1	$8	$112	$16,017	$6,889
2	$8	$112	$18,303	$8,679
3	$8	$117	$16,001	$6,905
4	$8	$112	$36,495	$20,672
5	$8	$112	$41,908	$25,489
6	$8	$117	$36,123	$21,043

D.8.2 NMPC SC6 as Supplemental

The costs for this strategy under the base and high gas scenarios were calculated by adding the DFSC, SC5-I, and SC6 components. An NMPC interruption affects both the amount of gas delivered under SC5-I and SC6 since an interruption is scheduled for October, when the Fort would otherwise receive all gas ordered from the DFSC. For the interruption scenarios, this strategy was calculated by adding the DFSC, SC5-I, and SC6 components adjusted for less gas along with the propane-air requirements in the interruption case. Table D.13 contains the results for this strategy.

TABLE D.13. SC5-I with SC6 (Strategy 11) (1992 $ thousands)

Scenario	Annual Energy Cost ($)	Annual Energy Cost Reduction Over Base ($)	Present Value of Energy Costs ($)	Capital Cost of Strategy ($)
1	$995	$288	$14,510	$950
2	$995	$288	$16,867	$950
3	$1,123	$160	$16,297	$950
4	$2,173	$1,025	$34,396	$1,393
5	$2,176	$1,022	$40,619	$1,393
6	$2,407	$791	$37,658	$1,393

Scenario	Average Annual O&M ($)	Present Value of Annual O&M ($)	Life-Cycle Cost ($)	Net Present Value of Strategy ($)
1	$3	$41	$15,460	$7,447
2	$3	$41	$17,816	$9,167
3	$6	$88	$17,293	$5,614
4	$3	$41	$35,769	$21,397
5	$3	$41	$41,992	$25,406
6	$6	$88	$39,078	$18,088

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