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* REGISTERED TO PRACTICE BEFORE THE U.S. PATENT AND TRADEMARK OFFICE
** NOT ADMITTED IN D.C.

October 30, 2003

VIA FEDERAL EXPRESS

The Honorable Jaclyn A. Brilling
Acting Secretary
State of New York
Department of Public Service
Three Empire State Plaza
Albany, NY 12223

Re: Incorporated Village of Rockville Centre – Application for Electric Rate Increase

Dear Secretary Brilling:

Enclosed herewith are the following materials, issued and transmitted for filing on behalf of the Incorporated Village of Rockville Centre, in accordance with the requirements of the Public Service Commission.

1. Revised tariff leaves for P.S.C. No. 3 Electricity, containing provisions and rates designed to produce an estimated annual aggregate increase in revenues of $2,581,000 based on forecast billing data for the twelve months ending May 31, 2005, as adjusted:

First Revised Leaf No. 4J
Second Revised Leaf No. 9
Twenty-Eighth Revised Leaf No. 11-B
Fifth Revised Leaf No. 11-C
Twelfth Revised Leaf No. 12

Fourteenth Revised Leaf No. 14-A
Thirteenth Revised Leaf No. 14-B
Thirteenth Revised Leaf No. 16

These revisions are issued as of October 30, 2003 and are proposed to be effective December 1, 2003

2. Testimony and exhibits which support the Village's requested increase in electric revenues.

The above leaves are filed for the purpose of increasing revenues from P.S.C. No. 3, Electricity, by $2,581,000 resulting in an overall increase of 14.6%, based on the forecast rate year ending May 31, 2005. Under the proposed revisions, the rate increase would be spread equally (i.e., uniform percentage increase) across all rate classes.

Submitted herewith are 15 copies of the proposed testimony and exhibits of the Village's witnesses supporting the Village's rate adjustments. Two sets of testimony and exhibits are being delivered to the Consumer Protection Board.

The Village has not filed for a rate increase since 1991. The primary reasons for this rate increase include inflationary cost pressures, higher costs for the New York State Retirement System and for medical and dental coverages for employees, the development of a new substation and to achieve a return sufficient to cover debt costs. In addition, tariff modifications have been submitted for filing, including changes to clarify the costs that are included in the Fuel Adjustment Clause (primarily related to the existence of the New York Independent System Operator) and to modify the application of the Fuel Adjustment Clause. Neither of these changes affect the amounts that are recovered from ratepayers. Other tariff changes include an increase in the reconnection fee, the addition of a late payment charge, elimination of the fuse replacement service and modifications to the power factor requirements.

Newspaper publication will be made in accordance with the Commission's regulations in the *Rockville Centre Herald* on four successive weeks.

Since public hearings will be required in connection with this filing, request is made for suspension of said filing and for an initial hearing to be held as soon as possible.

Accordingly, we respectfully request that the Public Service Commission expedite initiation of the requested proceedings and that the following individuals be advised of any action taken in consideration herewith: a) the undersigned; b) Paul J. Pallas, Superintendent of Village of Rockville Centre Electric Department, 110 Maple Avenue, Rockville Centre, NY 11571; c) Michael Schussheim, Comptroller, Village of Rockville Centre, 1 College Place, Rockville

Centre, NY 11570; and d) Howard S. Gorman, Vice President, R.J. Rudden Associates, 898 Veterans Memorial Highway, Hauppauge, New York 11788.

Respectfully submitted,

Jeffrey C. Genzer
Thomas L. Rudebusch
On behalf of the Village of Rockville Centre
jcg@dwgp.com
tlr@dwgp.com

vrcrateinccovltr103003.wpd

GENERAL INFORMATION

II. HOW SERVICE MAY BE OBTAINED: (Cont'd.)

B. Application: (Cont'd.)

4. Security Deposits - Non-residential Customers: (Cont'd.)

(f) Deposit Return: (Cont'd.)

(ii) may be credited to the account it secured in the amount of the next projected cycle bill, if applicable; and

(iii) may be credited to any other account of the customer not secured by a deposit, in the amount of the arrears on that account.

(3) If a balance remains after the Village has credited the customer's account(s) in accordance with paragraph (2) of this subdivision, a refund check shall be issued to the customer.

C. Fees:

1. All applications for service must be accompanied by a five ($5.00) dollar application fee except as noted herein below.

(a) No fees will be required in the event that a customer requires a larger meter or service due to existing or tentative increases in the demand for electric energy.

2. A ten ($10.00) dollar meter installation fee will be required for temporary service connection.

3. All applications for service after disconnection for non-payment must be accompanied by a reconnection fee in accordance with the following fee schedule:

(a) $15 when a service is reconnected with Meter Department personnel during regular business hours.
(b) $25 when a service is reconnected with Distribution Department personnel during regular business hours.
(c) $35 when service is reconnected outside normal business hours.

4. The Village charge for late payment of bills will be 1½ percent (1½%) for each monthly billing period for amounts billed, but for which the Village has not received payment by the "Due by" date on the bill.

D. Fire Underwriters' Certificates:

In the case of a new installation or major revision thereto, the application for service must be accompanied by a certificate of inspection as issued by the New York Board of Fire Underwriters and such certificate must indicate that the premises in question fully comply with the regulations as prescribed by the New York Board of Fire Underwriters. This installation must also comply with Municipal laws and/or ordinances governing electric installations.

GENERAL INFORMATION

B. 1. The consumer will be required to provide a galvanized iron eyebolt or bolts, not smaller than three-eighths (3/8") inches, firmly embedded in the wall for the attachment of the Village's service connection or other method as required to provide adequate support of the service wire.

2. The Village will use reasonable care and diligence in making its service connection to buildings but shall not be held liable for any defacing or injury caused to the building due to the wire supports, either in installing them or in their continued service.

XII POWER FACTOR

The Village reserves the right to make periodic tests for power factor, or to install suitable instruments to determine power factor over a period of time on any power installation. The Village further reserves the right to demand the installation of equipment for correcting low power factor on any installation which consistently continues to show power factor to be below 0.85. Failure to comply with this rule, within a reasonable period of time after due notice in writing has been given, may result in discontinuance of service.

GENERAL INFORMATION

XX ADJUSTMENT OF RATES DUE TO CHANGES IN COST OF FUEL

(a) Factor of Adjustment

The energy rates for electric service under Service Classification Nos. 1, 3 and 5 shall be subject each month to an addition or a deduction for each \$.0001, or major fraction thereof, increase or decrease in the estimated cost of fuel per kWh above or below the specified base cost of fuel.

(b) Base Cost of Fuel

The base cost of fuel, per kilowatthour is ..\$0.04641.

(c) Estimated Cost of Fuel

The estimated cost of fuel shall be determined monthly by dividing the sum of the estimates of (1) cost of fuel used by the Village plus (2) the cost of economy energy (see Rule XX(e)) purchased for its customers, plus (3) the fuel cost associated with other energy purchased for its customers plus (4) any current or future NYISO-related charges and fees, including, but not limited to, ancillary services, plus (5) any future regional transmission organization-related charges and fees of any kind, by the sum of (6) the estimated energy to be billed to the Village's customers for the upcoming month.

The estimated cost of fuel, as used herein, includes the cost of fuel, as billed by vendor, including all transportation taxes, if any, to the points at which the Village accepts delivery.

(d) Statement of Fuel Cost Adjustment

The rate of adjustment per kilowatthour, as determined above, shall become effective with the first billing cycle of the succeeding billing month and shall continue in effect until changed.

GENERAL INFORMATION

Not less than three business days prior to any change in the rate adjustment per kilowatthour resulting from this provision, a statement showing the base cost of fuel, the average cost of fuel the date at which and the period for which the average cost was determined, the amount of adjustment per kilowatthour, together with the period such rate adjustment per kilowatthour will remain in effect, will be duly filed with the Public Service commission, apart from this Rate Schedule. Such statement will be available to the public at village offices at which applications for service may be made.

(e) Economy Energy

Economy energy is that energy purchased at a total charge equal to or less than the Village's avoided fuel cost.

(f) Annual Surcharge or Refund

A surcharge or refund to recover electric fuel adjustment under-collections or refund electric fuel adjustment over-collections shall be computed as follows:

(1) By taking the cost of fuel, as defined in (c)above and subtracting therefrom an amount equal to
- (i) the base cost of fuel, as stated in (b) above, multiplied by the kWh available for distribution;
- (ii) the electric fuel adjustment revenues exclusive of revenue taxes; and
- (iii) (a) the calendar month' over-collection, or (b) adding the calendar month's under-collection.

(2) The amount derived in paragraph (1) above shall be divided by the estimated kWh to be sold in the upcoming calendar month.

(3) The determination period to be used in the computation of the surcharge or refund shall be a calendar month The initial period shall be the month ended June 30, 2005. The surcharge or refund computation shall be filed with the Commission monthly with the statement of fuel cost adjustment.

(4) The surcharge or refund shall be effective with the first billing cycle of each month. The initial surcharge or refund shall become effective with the first billing cycle in August, 2005.

SERVICE CLASSSIFICATION NO. 1

General Service - Small

APPLICABLE TO USE OF SERVICE FOR:

Any purpose by any customer whose demand is not metered and is estimated to be 5 kilowatts, or less.

CHARACTER OF SERVICE:

Continues sixty (6) cycle alternating current of the characteristics as listed below:
A. Single phase, 120/240 volts or 120/208 volts, or
B. Three phase, 120/208 volts or 277/480 volts

RATE: (per meter per month)

	WINTER BILLING PERIOD	SUMMER BILLING PERIOD
Customer Charge	$2.80	$2.80
Energy Charge, All kWh, per kWh	0.1127	0.1187

FUEL ADJUSTMENT:

The charges set this service classification shall be subject to a fuel adjustment as explained on Leaves Nos. 11B and 11C.

MINIMUM CHARGE:

$2.80 per meter per month exclusive of Fuel Adjustment.

INCREASE IN RATES AND CHARGES:

The rates and charges for this service classification, including fuel adjustment and minimum charge, are increased to reflect the tax rates applicable within the municipality where customer takes service.

See Rule XX-A.

Date of Issue October 30,2003
(Month Day Year)

Date Effective December 1, 2003
(Month Day Year)

Issued by Paul J.Pallas, Supt. of Utilities, Rockville Centre,NY 11571

SERVICE CLASSIFICATION NO. 3

Residential Service (Continued)

CHARACTER OF SERVICE (Continued)

Single phase, 120/240 volts, or 120/208 volts depending upon the characteristics of the circuit from which the load is to be supplied.

Three phase, 120/240, 120/208, or 277/480 depending up the characteristics of the circuit from which the load is to be supplied, available to religious organizations or associations, or supportive living facilities, as described above.

RATE: (Per meter bi-monthly)

	WINTER BILLING PERIOD	SUMMER BILLING PERIOD
Customer Charge	$5.63	$5.63
Energy Charge		
First 500 kWh, per kWh	0.1001	0.1001
Excess of 500kWh, per kWh	0.0982	0.1042
Excess of 1200 kWh (when Special Provision "A" applies per) kWh	0.0921	0.1042

FUEL ADJUSTMENT:

The charges set forth in this service classification shall be subject to a fuel adjustment as explained on Leaves Nos. 11B and 11C.

MINIMUM CHARGE:

$5.63 per meter bi-monthly, exclusive of fuel adjustment.

INCREASE IN RATES AND CHARGES:

The rates and charges for this service classification, including fuel adjustment and minimum charge, are increased to reflect the tax rates applicable within the municipality where customer takes service.

See Rule XX-A.

SERVICE CLASSIFICATION NO. 3

Residential Service (Concluded)

TERMS OF PAYMENT:

Charges for electric current are due and payable when rendered.

TERM:

Terminable on three days' written notice by the customer or by the Village in accordance with law or the provisions of this rate schedule.

SPECIAL PROVISIONS:

A. The Energy Charge of 0.0921 per kWh for use in excess of 1200 kWh per bi-monthly period is applicable during the months of October through May inclusive where the service furnished under this service is used by the customer for the operation of electric space heating equipment which is permanently installed and exclusively supplied, and is adequate to supply the entire space heating requirements of such customer's premises served hereunder, and no other space heating equipment is connected or available for use in such premises.

B. Submetering may be available according to certain conditions set forth in XIX RESALE.

C. The summer billing period shall be the four month period from June 1 through September 30 and the winter billing period shall be the balance of the year. When a bill includes periods during both the summer billing period, and the winter billing period, the applicable rates and charges will be prorated based on the number of days in the summer billing period and the number of days in the winter billing period related to the total number of days in the billing period.

SERVICE CLASSIFICATION NO. 5

General Service - Large

APPLICABLE TO USE OF SERVICE FOR:

Any purpose by any customer whose demand is more than 5 kW or whose consumption exceeds 2,000 kWh in each of two consecutive monthly billing periods.

CHARACTER OF SERVICE:

Continuous sixty (60) cycle alternating current of the characteristics as listed below:

A. Single phase 120/240 volts or 120/208 volts, or three phase 120/208 volts (secondary).

Three phase 2400/4160 volts (high tension).

RATE: Two Part Rate

DEMAND CHARGE (Per kW per month)

Secondary Service	High Tension Service
$4.18	$3.56

ENERGY CHARGE (Per meter per month)

First 30,000 kWh, per kWh	$0.0896
Excess of 30,000 kWh, per kWh	$0.0805

FUEL ADJUSTMENT:

The charges set forth in this service classification shall be subject to a fuel adjustment as explained on Leaves Nos. 11B and 11C.

Paul J. Pallas

INCORPORTED VILLAGE OF ROCKVILLE CENTRE

DIRECT TESTIMONY OF PAUL J. PALLAS

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Paul J. Pallas and I am the Superintendent of the Village of Rockville Centre Electric Department. My business address is 110 Maple Ave., Rockville Centre, New York 11571

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelors Degree in Engineering from Hofstra University in 1982. I received a Masters Degree in Business Administration from Dowling College in 1996. I am a Licensed Professional Engineer registered in the State of New York. From 1982 through 1993, I worked for the Long Island Lighting Company in various capacities starting as a substation design engineer then in the customer design area as area manager. In 1993 I started with the Village of Rockville Centre as Deputy Superintendent of the Electric Department with responsibility for the construction and startup of a new substation and generator. Upon completion of this project I assumed responsibility for the general operation of the electric department assisting the superintendent. In 1995 I was promoted to Superintendent of the department with complete responsibility for the operation of the utility. As part of my duties I managed the transition of the utility from a regulated environment to the deregulated wholesale market, working with the New York Independent System Operator. This includes day-to-day energy scheduling and participation in various NYISO committees.

Q. PLEASE STATE ON WHOSE BEHALF YOU ARE TESTIFYING AND BRIEFLY DESCRIBE THE PURPOSES OF YOUR TESTIMONY.

A. I am testifying on behalf of the Village. My testimony will address the following:

- Overview of this filing.
- Description of, and support for, increases in Reconnection Fees and Late Payment charges, as well as changes to tariff language, that are being requested.
- Description of planned new substation.

OVERVIEW

Q. PLEASE SUMMARIZE THE VILLAGE'S REQUESTS IN THIS PROCEEDING.

A. In this filing, the Village is requesting a rate increase, as well as several changes to tariff language. The Village is requesting a rate increase of approximately $2.6 million. This increase is necessary for the Village to recover all of its electric operating costs as well as to provide a return to cover the cost of debt. The Village is proposing that all rates and charges be increased by a uniform percentage, 14.6%, which would increase the average cost per kWh from approximately 8.969 ¢ / kWh to 10.282 ¢ / kWh. The filing is based on actual results for the Test Year, which is the Village's fiscal year ending May 31, 2003, and projected results for the Rate Year, which is the year ending May 31, 2005. The changes to tariff language are to clarify the costs that are included in the Fuel Adjustment Clause, and to change the Fuel Adjustment Clause calculation from a retroactive to prospective approach. In addition, the Village is requesting to increase Reconnection Charges to reflect actual costs and to add a Late Payment Charge to provide an incentive for timely payment by customers.

Q. PLEASE PROVIDE AN OVERVIEW OF THE TESTIMONY SUBMITTED IN THIS PROCEEDING.

A. The Village's proposal is supported by my testimony as well as that of Mr. Michael Schussheim, Mr. Howard S. Gorman and Mr. Michael Marks.

In my testimony, I will provide background on the Electric Department. I will also discuss the reasons why the new substation is needed, and the estimated cost. In addition, I will describe the changes to tariff language that are being proposed, and explain why each is necessary, and will describe why the increases to the Reconnection Fee is necessary. Mr. Michael Schussheim, the Comptroller of the Village, will support the Test Year historical data, the cost of debt, and the Village's decision to finance the new substation over 15 years and the benefits that ratepayers can expect to see from that decision. Mr. Gorman, a Vice President with the consulting firm of R. J. Rudden Associates, Inc., will develop the Rate Year Revenue Requirement, Rate Base and Rate of Return, based on Test Year data and appropriate adjustments. He will also present the proposed Rates and Charges that will produce the indicated Revenue Requirement, the related revenue forecast, and rate comparisons.

Mr. Marks, a Principal with the consulting firm of Applied Energy Group, Inc., will provide testimony in support of the sales forecast used in developing revenue requirements and rates.

Q. WHAT ARE THE PRIMARY REASONS FOR THE RATE INCREASE?

A. The Village filed its last rate increase in 1991. Prior to the 1991 filing the last increase was in 1980. Since 1991, the Village has avoided the need to file for a rate increase by carefully managing costs and has actually decreased Electric Department personnel by one. As our generation usage has been reduced through increased purchases we have reallocated and retrained personnel to perform other functions, with a result of increased efficiency. This was done even while managing the transition to a deregulated market handling all aspects of market-based operation with existing personnel. However, an increase is needed at present due to inflationary cost increases, much higher costs for the New York State Retirement System and for Dental / Medical, the need to achieve a return sufficient to cover debt costs, and to recover the additional costs of the planned new substation.

Q. PLEASE DESCRIBE BRIEFLY THE HISTORY AND OPERATION OF THE VILLAGE ELECTRIC UTILITY.

A. Located on the Maple Avenue site it occupies today, the utility began generating electricity for street lights on February 18, 1898. Originally, electricity was generated only during the hours of darkness – it was not until 1900 that people asked to have their homes connected into the system. Among the first customers was St. Agnes Church, which turned on the lights for early masses and evening weddings. Just eight years after it began, records show 285 customers used 88.35 kilowatts of power during the utility's 13-hour days. During 2003, by contrast, usage was approximately 196 million kilowatt hours. The introduction of electric motors brought about 24-hour operations, and in 1925 the first section of the current plant was built to house three diesel engines. Rockville Centre has been importing NYPA power since 1976 and its current allocation provides approximately 85% of annual energy needs. This is supplemented with Village owned and operated generation and supplemental purchases through the NYISO. The present interconnection is through a LIPA substation located approximately one mile from the Maple Ave site with two Village owned transmission lines. At the Maple Ave site there are four transformers, two rated at 5.6MVA and two rated at 15MVA. The power plant remains a vital resource for Rockville Centre as a supplement to purchased power and in the event of system-wide incidents.

CHANGES IN TARIFF LANGUAGE

Q. WHAT TARIFF LANGUAGE CHARGES ARE BEING REQUESTED?

A. In addition to the changes in charges described above, changes to the fuel adjustment clause are being requested. The first change is to reflect the changes in the market. Language is being added to capture all charges related to the purchase of energy, specifically those charges associated with the NYISO such as ancillary service charges and capacity charges. A change in methodology is detailed in Exhibit No. ____ (PJP-1) Schedule 1-3. Presently, fuel costs incurred during the calendar month are used to calculate the fuel adjustment charge for bills rendered during the upcoming billing period, usually beginning on the 15th of the month and continuing to the 15th of the following month. During the peak summer months this creates a lag in our receipts for these expenses. For example, during the billing period that begins in mid-June we are collecting fuel charges that are based on expenses incurred in May. During fiscal year 2003 in June and July we under-recovered over $600,000 in fuel costs. This shortfall, combined with the prior year carryover of over $200,000, put the total under-collection at over $800,000. The Village must carry this deficit until the collections increase during the off-peak months. Since there are less kwh's during the off-peak months there is a longer time period to catch up with the under-collection. We propose to prospectively estimate the fuel charges and sales during a calendar month and perform a twelve-month rolling reconciliation each month to allow for errors in the estimating process. Due to the nature of the timing of invoices for actual fuel costs, this reconciliation would have a one month lag. For example, if total fuel costs for June were estimated at $800,000 and sales were estimated at 16,000,000 kwh, the cost of fuel would be $.05 per kwh. Subtracting out the base cost of fuel of $.04641 per kwh the fuel adjustment would be $.0036 per kwh. If the actual costs were $780,000 and actual sales were 15,500,000 the actual fuel adjustment should have been $.0039 per kwh. The difference between these values would be spread for twelve months beginning in August. The first month of the application of this new procedure would be June 2005.

RECONNECTION FEE AND LATE PAYMENT CHARGE

Q. WHAT IS THE REASON FOR THE INCREASE IN THE RECONNECTION FEE?

A. The present fee of $5 has been used for many years and does not reflect our actual cost to provide this service. We believe that the customer who caused this work should bear the cost of this work. Reconnections are performed by two different types of personnel. When only a meter is involved our meter department will perform this task. At the present pay scales and an average of 1/2 hour to reconnect the meter the cost would be approximately $15. When a line maintainer is required to perform this work the cost increases to approximately $25. If this work is required after normal business hours the work would be performed by a line maintainer at a cost of approximately $35.

Q. WHAT IS THE REASON FOR THE IMPOSITION OF A LATE PAYMENT CHARGE?

A. Presently there is no disincentive for customers to make late payments prior to reaching the point of disconnection. There are a number of customers who will consistently pay at the last minute, usually when we have already sent someone to the service location to perform a disconnection, before paying. Imposing a late payment fee in accordance with the statute will provide an incentive for customers to make timely payments.

<u>SUBSTATION</u>

Q. WHAT ARE THE PRIMARY REASONS FOR THE ADDITION OF A NEW SUBSTATION?

A. The main component of our five year-capital plan, Exhibit No.____ (PJP-2), is the addition of a new substation. The project will install a new transmission substation at 33kv interconnected with an existing 33kv LIPA-owned transmission line. The LIPA-owned transmission line will require reconductoring to accommodate the new substation load. Two 20MVA, 33kv/4kv substation transformers will be installed along with new distribution switchgear that will have two line circuit breakers, a bus tie circuit breaker and a minimum of 10 distribution circuit breakers. The substation will provide two important benefits. First, it will allow greater access to market-based energy which is currently capped at approximately 30MWs due to Rockville Centre transmission limitations. By adding this substation we will be able to import approximately up to our peak load when this is the most economic option. The second benefit is the ability to move cables from existing circuit breakers that currently have two or three circuits connected. During cable failures uninvolved circuits are impacted when the circuit breaker trips. By reducing the number of cables attached to the circuit breakers we will minimize the impact of outages and aid in the troubleshooting process. This will improve reliability.

Q. IS THE VILLAGE PLANNING ANY GENERATION ADDITIONS?

A. The capital plan presented here does not have any generation projects listed at this time. However, this does not mean that more generation is not contemplated. At the present time, the Village is in the beginning stages of evaluating our capacity needs. Although our recently completed Integrated Resource Plan, Exhibit No. ____ (MM-2), discussed generation additions, two factors have caused this aspect of our capital plan to be delayed. The first issue is new environmental regulations currently in process that will be issued by the New York State Department of Environmental Conservation that may significantly impact the status of our existing generation facility. These regulations are not expected to be issued until the first quarter of 2004, with a compliance date of April 2005. The second issue concerning generation is the impact of the NYISO demand curve on our cost of purchased capacity and the amount of locational capacity required. Our intention is to study these issues over the next 12-18 months and develop a comprehensive capacity plan taking into account these two issues, and other factors as necessary.

NYPA REFUND

Q. WHAT TREATMENT IS THE VILLAGE REQUESTING FOR THE BALANCE OF THE NYPA REFUND RELATING TO THE SETTLEMENT OF THE *BERGEN, ET. AL. V. PASNY* CASE?

A. The village will be filing a separate request for this purpose.

DEMAND-SIDE MANAGEMENT

Q. WHAT DEMAND-SIDE MANGEMENT INITIATIVES IS THE VILLAGE EXPLORING?

A. The Village is exploring two significant programs to control demand. The first is with our largest customer, South Nassau Community Hospital. As described in our capital plan, a major expansion of this facility is expected in the near future. As part of this expansion we have been in discussions with the facility managers to participate in the demand reduction programs associated with the NYISO. As part of their expansion the hospital is installing new backup generation as required by regulation. The plan is to design the generation with the NYISO demand response program in mind and to utilize low sulfur fuel in order to meet the environmental restrictions of the program. The second initiative the Village is beginning to explore is partnering with LIPA in their LIPA Edge program. This program will allow the Village to control central air conditioners via an internet connection. We have discussed this with LIPA's consultant on this project and it is our understanding that this would be acceptable to LIPA. Although not a formal program, during high load periods we work with our largest customers to reduce load. Through phone contact and personal visits these customers are contacted when high loads are anticipated and contacted again when a specific request for load reduction is requested. Public appeals are also issued through the Village television station and web site in an attempt to reach residential customers. We have found this to be very effective and estimate that the process reduces load by 1000kw on a peak of approximately 50,000 kw.

Q. I HAVE NO FURTHER QUESTIONS AT THIS TIME.

Howard S.
Gorman

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

DIRECT TESTIMONY OF HOWARD S. GORMAN

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Howard Gorman. I am a Vice President with R. J. Rudden Associates, Inc. ("Rudden"). My business address is 898 Veterans Highway, Hauppauge, NY 11788.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have 15 years experience in the energy industry and 24 years of experience covering all areas of finance. At Rudden, I have performed numerous assignments in the development of revenue requirements, electric and gas industry accounting and costing, financial modeling, forecasting and analysis, accounting systems, fully allocated cost of service studies, rate design and competitive practices. My assignments have also included energy project financing and analysis; energy asset valuations, acquisitions and divestitures; mergers and related management and organizational matters; economic and financial planning; and computer modeling and information systems. I am a co-developer and implementer of Rudden's proprietary electric and natural gas unbundled cost of service models.

Prior to joining Rudden, I was Controller and Treasurer of Trigen Energy Corporation, the largest U.S. owner and operator of district heating/cooling systems including cogeneration plants. Before working at Trigen, I was employed by Touche Ross & Co. (now Deloitte & Touche LLP), and by Coleco Industries, Inc., a consumer leisure products company. I have a B.S. in accounting from New York University and an MBA from Harvard Business School. I am a New York State Certified Public Accountant.

Rudden provides economic, management and financial consulting services to utilities and their customers throughout North America and internationally. Founded in 1981, we have approximately 100 consultants. Our headquarters office is in Hauppauge, New York with regional offices in Washington, D.C., Houston, TX, Atlanta, GA and Augusta, ME. Rudden's major practice areas include: utility pricing; regulatory policy analysis; strategic and market planning; market research, demand forecasting and marketing; merger and acquisition assistance; generation and transmission planning; energy project management, financing and analysis; fuels analysis and acquisition; and litigation support and testimony. Our clients include electric and gas utilities subject to FERC and state regulation, energy producers and consumers, other industrial and commercial organizations, financial institutions and the U.S. and Canadian government.

Q. **PLEASE STATE ON WHOSE BEHALF YOU ARE TESTIFYING AND BRIEFLY DESCRIBE THE PURPOSES OF YOUR TESTIMONY.**

A. I am testifying on behalf of the petitioner, the Incorporated Village of Rockville Centre ("Village"). The purposes of my testimony are to develop the Rate Year Revenue Requirement, Rate Base and Rate of Return, based on Test Year data and appropriate adjustments, and to present the proposed Rates and Charges that will produce the indicated Revenue Requirement, the related revenue forecast, and rate comparisons.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR TESTIMONY.

A. Under the present rates, the Village would have a shortfall of approximately $2.6 million in revenue compared to revenue requirements for the Rate Year. Therefore, the Village is proposing that all rates and charges be increased by a uniform percentage of 14.6%, as shown on Exhibit No. __ (HSG-4) Schedule 1. This would increase the average cost from approximately 8.969 ¢/ kWh to 10.282 ¢/ kWh, as shown on Exhibit No. __ (HSG-5) Schedule 1. The electric revenue produced by the new rates, $20,211,504, would recover the costs forecast to be incurred by the Village in the Rate Year, including a 5.01% return on the rate base, as shown on Exhibit No. __ (HSG-6) Schedule 1. This filing is based on actual results for the Test Year, which is the Village's fiscal year ending May 31, 2003, and forecast for the Rate Year, which is the year ending May 31, 2005.

Q. WHY IS AN INCREASE IN RATES NEEDED?

A. An increase is needed at present due to inflationary cost increases, much higher costs for the New York State Retirement System and for Dental / Medical, the need to achieve a return sufficient to cover debt costs, and to recover the additional costs of the planned new substation.

Q. PLEASE DESCRIBE THE APPROACH USED TO DEVELOP THE PROPOSED RATES.

A. Exhibit No. __ (HSG-1) is an Index of the other exhibits in my testimony, Exhibit No. __ to __ (HSG-2 to HSG-7).

First, information about Test Year sales, revenue, rate base and operating expenses was obtained. This information is presented in Exhibit No. __ (HSG-2), Schedules 1-7. The information on those schedules was developed from the Village's accounting and financial records, and the Village's Comptroller, Michael Schussheim, who is testifying behalf of the Village, has confirmed the information is accurate and complete.

Second, the Rate Year forecast of electric sales in kWh by customer type was obtained. This forecast was provided by Michael Marks, who is also testifying behalf of the Village. This forecast was developed in further detail in order to compute monthly sales in kWh by Rate Class or subclass. These results are presented in Exhibit No. __ (HSG-5), Schedule 5.

Third, the Electric Production Costs included in the Fuel Adjustment Clause (FAC) in the Test Year were analyzed, and the Electric Production Costs for the Rate Year were forecast using this information and the sales forecast. These results are presented in Exhibit No. __ (HSG-3), Schedules 1-2.

Fourth, Rate Year costs were forecast. This includes operating and maintenance costs, depreciation expense and other items. This was done by starting with the actual costs for the Test Year, detailed by account and by function, then making known and measurable adjustments. These results are presented in Exhibit No. __ (HSG-7), Schedules 1-13.

Fifth, the Rate Base for the Rate Year was forecast, and the required Net Electric Operating Income was developed using the Rate of Return that I have developed. This computation indicated that Rate Year electric revenue of $20,211,504 is required to produce the required Rate of Return. These results are presented in Exhibit No. __ (HSG-6), Schedules 1-6.

Finally, proposed rates were developed that produce the indicated electric revenue in the Rate Year. The proposed new rates are shown on Exhibit No. __ (HSG-4), Schedule 1. The amounts that typical ratepayers can expect to pay under the proposed rates is compared to the amounts they would pay under the present rates on Exhibit No. __ (HSG-4), Schedule 2. The computation of Rate Year revenue under the proposed rates, with a comparison to Rate Year revenue under the present rates, is shown on Exhibit No. __ (HSG-5), Schedules 1-4.

Q. WHAT SERVICE CLASSIFICATIONS DOES THE VILLAGE USE TO REPORT SALES AND REVENUE?

A. The Village has three active service classifications in the tariff, SC-1, SC-3 and SC-5, and reports sales and revenue using the following classifications:

- SC-1: General Service- Small;
- SC-3: Residential;
- SC-3A: Residential- Special Provision A (Space Heating);
- SC-5: General Service- Large;
- Street Lighting- which takes service under SC-5;
- Operating Municipality- which takes service under SC-5; and
- Public Authorities, which take service under SC-1.

Q. WHAT ARE THE BILLING CYCLES?

A. SC-3 and SC-3A are bi-monthly billing cycles, and SC-1 and SC-5 are monthly. SC-3 and SC-5 have blocked rates, SC-5 has a two-tier demand charge with a 5 MW minimum and a ratchet, and the energy charges for SC-1 and SC-3 have Summer / Winter differentiation. Summer is June 1 through September 30, and Winter is the balance of the year. Bills that cover more than one period are pro-rated based on number of days.

Q. WHY ARE YOU PROPOSING A UNIFORM PERCENTAGE INCREASE IN RATES?

A. A uniform increase in rates is appropriate because:

- The cost structure of the Electric Department is very similar to that in the 1992 rate case, with Production accounting for approximately 80% of total costs (excluding General & Administrative and Non-Operating Costs) in both cases.
- The composition of kWh sales is very similar to that in the 1992 rate case, with Residential approximately 47%, Commercial 50% and Other 3%.
- A uniform rate increase is the simplest to implement, and Village management believes it would be the most acceptable to ratepayers.
- A cost of service study would be expensive and time-consuming.

TEST YEAR INFORMATION

Q. PLEASE DESCRIBE THE TEST YEAR INFORMATION ON EXHIBIT NO. __ (HSG-2).

A. Exhibit No. __ (HSG-2), Schedules 1-3 computes Test Year revenue using the present rates and Test Year billing units. Billing units are sales in kWh, numbers of customers and bills, and demand in kW. Test Year total electric revenue is $17,571,183 based on the Village's financial records. Applying present rates and Test Year billing units, total revenue was computed within 0.5% of actual, or $93,000. The difference is due to the use of estimates in applying blocked rates and billing cycle pro-ration. This difference is considered very slight, and the cost of obtaining more precise data would be prohibitive. Schedules 4 and 5 compute the return on rate base and the rate base for the Test Year. Schedule 4 shows that the actual return was 2.06%. Schedule 6 shows the details of operating expenses, by function (Production, Transmission, Poles, Distribution, Street Lights, Customer Accounts, General & Administrative, and Non-Operating). These amounts were used to develop the forecast of Rate Year expenses. Schedule 7 shows the calculation of the gross utility tax multipliers that are applied to revenue.

SALES FORECAST

Q. HOW WAS THE SALES FORECAST DEVELOPED FOR THE RATE YEAR?

A. The Rate Year forecast of electric sales in kWh by customer type was provided by Mr. Marks, showing sales of 197,887,000 kWh in the Rate Year. The forecast included a planned apartment complex with electric service assumed to begin mid-way through the Rate Year, however due to the lengthy nature of the review process for this apartment complex, the associated sales were eliminated from the Rate Year forecast, and the total sales were 196,573,000 kWh.

The forecast presented annual sales, with subtotals for Residential, Commercial and Other. Using the same ratios as computed for Test Year sales:

- Residential was split between Residential (SC-3) and Residential- Special Provision A (SC-3A);
- Commercial was split between large (SC-5) and small (SC-1); and
- Other was split among Street Lighting, Operating Municipality Public Authorities.

Then, the annual sales were split into monthly sales forecasts, by applying actual historical data from the 11-year period 1993-2003. This data was available for each of Residential, Commercial, Street Lighting, Operating Municipality and Public Authorities. The resulting Rate Year sales forecast is on Exhibit No. __ (HSG-5), Schedule 5.

Q. HOW WERE BILLING UNITS FOR NUMBER OF CUSTOMERS AND DEMAND DEVELOPED FOR THE RATE YEAR?

A. Rockville Centre is a mature, stable community. Therefore, any sales growth is likely to come from increased usage per customer, with the number of customers and number of bills remaining the same.

The sales forecast included a forecast of peak demands. After eliminating the effect of the planned apartment complex, and adjusting for the fact that approximately 90% of demand charge revenue is from customers that are below the minimum, an increase of 0.33% was applied to billed demand units for the Rate Year over the Test Year.

<u>ELECTRIC PRODUCTION COSTS FORECAST</u>

Q. **HOW DOES THE VILLAGE OBTAIN ELECTRICITY TO MEET CUSTOMER REQUIREMENTS?**

A. The Village obtains electricity from three sources. It has a nominal 29 MW allocation of low-cost hydroelectric power from the Power Authority of the State of New York (PASNY). It can generate up to 33 MW using its own oil and gas fired generation. It can purchase electricity from the grid operated by the New York Independent System Operator (NYISO). Purchases from PASNY and through the NYISO include the cost of energy as well as ancillary services, and reduce the Transmission Congestion Credit (TCC) that the Village receives.

Q. **DID YOU ANALYZE ELECTRIC PRODUCTION COSTS FOR THE TEST YEAR?**

A. Yes, electric production costs for the Test Year were obtained and analyzed. These costs are presented in the top half of each page of Exhibit No. __ (HSG-3), Schedule 1. The formula for each column is shown as well. Page 5 shows the cost per kWh for each component of electric production costs, by month.

Q. **DID YOU COMPUTE THE ELECTRIC PRODUCTION COSTS FOR THE RATE YEAR?**

A. Yes, electric production costs for the Rate Year are presented in the bottom half of each page of Exhibit No. __ (HSG-3), Schedule 1. The first step was to determine the total kWh needed, based on the sales forecast. Then, it was assumed that the kWh of electricity purchased from PASNY and generated by the Village would each be the same in the Rate Year as the Test Year, and the balance of kWh required would be purchased through the NYISO. Column h shows the total to be purchased through the NYISO in the Rate Year is 37,062,223 kWh.

Next, it was assumed that the cost per kWh of each component will be the same in the Rate Year as the Test Year. These unit costs were applied to the monthly kWh purchased from PASNY, generated by the Village or purchased through the NYISO, to calculate the total for the Rate Year, shown in column aa to be $9,122,457.

Q. **IF ACTUAL USAGE, OR ACTUAL ELECTRIC PRODUCTION COSTS, DIFFER FROM THE AMOUNTS SHOWN ON THIS SCHEDULE, WHAT WILL BE EFFECT ON THE VILLAGE AND THE RATEPAYERS?**

A. Actual electric production costs are passed through to ratepayers under the Fuel Adjustment Clause in the tariff. Therefore, even if actual usage and actual costs differ from the amounts shown on this Schedule, ratepayers will pay no more or less, and the Village will receive no more or less.

RATE YEAR COSTS

Q. **PLEASE LIST THE TYPES OF COSTS INCLUDED IN RATE YEAR COSTS.**

A. These costs include operating and maintenance costs, depreciation expense and other items.

Q. **HOW DID YOU FORECAST RATE YEAR OPERATING AND MAINTENANCE COSTS?**

A. The Test Year actual costs shown on Exhibit No. __ (HSG-2), Schedule 6 by account, by function were analyzed. A list of known and measurable adjustments was developed. The adjustments are shown on Exhibit No. __ (HSG-7), Schedule 3. The adjustments were applied to each account, by function. Exhibit No. __ (HSG-7), Schedules 6-13 show the Test Year costs by account, by function, the adjustments applicable, and the resulting Rate Year costs.

Q. PLEASE BRIEFLY DESCRIBE THE KNOWN AND MEASURABLE ADJUSTMENTS THAT WERE APPLIED.

A. The adjustments shown on Exhibit No. __ (HSG-7), Schedule 3 are summarized below:

- Contractual increase in labor costs, effective June 2003 through May 2006, and related increases in employee benefits and payroll taxes.
- General inflationary increase for costs other than labor-related costs, shown on Exhibit No. __ (HSG-7), Schedule 5.
- Increase in Medical costs based on estimate provided by New York State fund; increase in required New York State Retirement System contributions shown on Exhibit No. __ (HSG-7), Schedule 4; and contractual increase in Life Insurance costs.
- Additional costs for annual testing of the new substation, and to add a person to support NYISO purchasing and scheduling.
- Elimination of $2 million non-recurring Special Contracts Expense from both costs and revenue.
- Estimated Bad Debts expense.
- Amortization of estimated rate case costs over two years.

Q. HOW DID YOU FORECAST RATE YEAR DEPRECIATION EXPENSE?

A. Exhibit No. __ (HSG-6), Schedule 5, page 1 shows the Village's electric assets at cost by account, as of May 31, 2003, the end of the Test Year. Page 2 shows the accumulated depreciation. Asset cost balances at May 31, 2004 and 2005 were computed by adding planned capital additions and removing planned retirements. Depreciation expense for the years ended May 31, 2004 and 2005 (the Rate Year) was computed by applying depreciation rates to the average of beginning- of-year and end-of-year asset cost balances. Accumulated depreciation balances at May 31, 2004 and 2005 were computed by adding depreciation expense and removing planned retirements, assuming that retired assets are fully depreciated. Rate Year depreciation expense is included on the schedules of Exhibit No. __ (HSG-7).

Q. **IS THE COST OF THE NEW SUBSTATION INCLUDED IN THE SCHEDULE OF ASSETS?**

A. The new substation is expected to be placed in service during the Rate Year. This asset is estimated to cost $5 million. Because it is a significant addition to the Rate Base, Exhibit No. __ (HSG-6), Schedule 5 includes it on a pro forma basis for the full Rate Year.

The depreciable life used for the new substation is 15 years. As Mr. Schussheim discusses, the Village usually issues debt with 15-year or shorter term final maturity, in order to maintain or improve its credit rating, avoid over-burdening future residents, taxpayers and ratepayers (as the case may be) and minimize the aggregate cost of debt. The typical depreciable life for substation assets is 35.5 years, but this would cause depreciation expense to be insufficient to fund the principal payments on the debt. This will create cash flow pressures for the Village. The Village does not wish to alter its financial policy. Therefore, the depreciable life used for the substation is 15 years, to match the term of the associated debt and to support the Village's financial policy. Mr. Schussheim demonstrates that this will save ratepayers money over the long term.

Q. **WHAT OTHER ITEMS ARE INCLUDED IN THE RATE YEAR COSTS?**

A. Rate Year costs also include tax equivalency expense and gross utility tax. Tax equivalency expense was computed using the same methodology as used in the Village's last prior rate case in 1992. A 1% gross utility tax applies to all electric revenue, except for approximately 13% of revenue (virtually all of which is from Large Commercial users) representing sales made outside the Village. The appropriate gross utility tax multipliers, developed on Exhibit No. __ (HSG-2), Schedule 7, were applied to the revenue developed on Exhibit No. __ (HSG-5), Schedules 1-2, resulting in the Rate Year amount shown for gross utility tax shown on Exhibit No. __ (HSG-6), Schedule 1.

Q. **DID YOU PREPARE A SUMMARY OF THESE COSTS?**

A. Yes. Exhibit No. __ (HSG-7), Schedule 1 summarizes Rate Year costs for each account, by function. Exhibit No. __ (HSG-7), Schedule 2 compares the Rate Year totals for each account to the Test Year totals.

<u>RATE BASE, RATE OF RETURN AND NET ELECTRIC OPERATING INCOME</u>

Q. **HOW DID YOU DEVELOP THE RATE BASE?**

A. First, forecast balance sheets were prepared for May 31, 2004 and 2005. The balance sheets are presented in Exhibit No. __ (HSG-6), Schedule 4. Assets and accumulated depreciation were obtained from Exhibit No. __ (HSG-6), Schedule 5. Construction

Work in Progress was assumed to remain at the same amount as at May 31, 2003. Each other asset, except Cash and Investments, was assumed to be the average of the actual amounts for May 31, 2002 and 2003. Long Term Debt was based on the repayment schedule for outstanding debt, plus a pro forma issuance of $5 million new debt to finance the new substation. Payables was assumed to be the average of the actual amounts for May 31, 2002 and 2003. The deferred credit was assumed to be liquidated by May 31, 2004. Surplus was assumed to remain the same as at May 31, 2003. Cash and Investments was computed as the amount necessary to make the balance sheets balance.

Then, the Rate Base was developed using the appropriate accounts from the forecast balance sheets, plus an allowance for Cash Working Capital determined by using the widely-accepted formula of 1/8 of non-fuel cash operating costs plus 1/12 of fuel and purchased power costs. The Rate Base for the Rate Year is presented in Exhibit No. __ (HSG-6), Schedule 3.

Q. **WHAT FACTORS DID YOU CONSIDER IN DEVELOPING THE RATE OF RETURN?**

A. The rate of return must provide a fair return on invested capital. It must 1) cover the cost of the utility's embedded debt and 2) provide a fair return on the Village's invested surplus. If the rate of return does not cover the cost of embedded debt, it would impair the ability to raise debt for necessary capital expansion, and would jeopardize the credit rating of the Village. If the rate of return does not provide a fair return on invested surplus, the Village would benefit by replacing the surplus financing with debt financing, in which case the utility would have to bear the cost of additional embedded debt, at a much higher rate than at present due to the greater risk to debt-holders that all-debt financing would create.

Q. WHAT OVERALL RATE OF RETURN DID YOU USE FOR THE VILLAGE?

A. The rate of return of 5.01% is developed on Exhibit No. __ (HSG-6), Schedule 2. It reflects the weighted average of:

- Actual cost of the utility's embedded debt, 5.75%;
- Actual cost of customer deposits, 1.50%;
- Pro forma cost of new year debt assumed to be issued for the new substation, 4.50%; and
- Cost of surplus / New debt, estimated to be 5.00%.

Q. HOW DID YOU DETERMINE THE PRO FORMA COST OF NEW DEBT TO BE ISSUED FOR THE SUBSTATION?

A. Mr. Schussheim testifies that it is the financial policy of the Village to issue debt with maturity of 15-years or shorter term final maturity when possible, and the Village has obtained information from its financial advisor that 15-year debt would be required to yield 4.50%. Assuming that a 15-year depreciable life is used for the substation, this is the appropriate rate of return for the new debt for the substation.

Q. HOW DID YOU DETERMINE THE COST OF SURPLUS / NEW DEBT?

A. The rate of return on surplus must at least equal the rate that the Village would have to pay if it decided to replace the surplus financing with debt financing; i.e., the avoided cost of debt financing. The cost of debt financing to replace the surplus would be greater than the cost of new debt for the substation, because if the utility had 100% debt financing, the risk to debt-holders would be greater than at present, where the ratio is approximately 50% debt / 50% surplus. The greater risk would require a higher yield. In addition, in order to be able to meet debt service, the maturity of the debt would extend beyond 15 years. To reflect these considerations, 50 basis points was added to the cost of 15-year debt, and the result is an estimated 5.00% rate of return.

Q. HOW DID YOU COMPUTE THE REQUIRED NET ELECTRIC OPERATING INCOME?

A. The required net electric operating income is computed by multiplying the Rate Base, $26,451,267, by the Rate of Return, 5.01%. The result is $1,325,208.

PROPOSED RATES

Q. DID YOU PREPARE A SUMMARY OF THE PROPOSED RATES?

A. Yes, the proposed rates are summarized on Exhibit No. __ (HSG-4), Schedule 1. Each of the rates was increased by the same percentage.

Q. DID YOU COMPUTE THE RATE YEAR REVENUE THAT WILL BE PRODUCED FROM THE PRESENT RATES AND THE PROPOSED RATES?

A. Exhibit No. __ (HSG-5), Schedule 1 shows the Rate Year revenue that is produced using the present rates and proposed rates, and the Rate Year billing units. The details of these computations are on Exhibit No. __ (HSG-5), Schedules 2-4. In addition, the Fuel Adjustment Clause monthly amounts under the present and proposed rates are computed on Exhibit No. __ (HSG-3), Schedule 2.

Q. **DO THE PROPOSED RATES PRODUCE THE REQUIRED NET ELECTRIC OPERATING INCOME?**

A. Yes, Exhibit No. __ (HSG-6), Schedule 1 shows that revenue from sales of electricity of $20,211,504 is needed to produce the required net electric operating income. This revenue will be sufficient to cover the operating and maintenance expenses, depreciation expense, tax equivalency and gross utility tax developed above. Adjustments to Test Year revenues that affect the Rate Year are on Exhibit No. __ (HSG-6), Schedule 6. Exhibit No. __ (HSG-5), Schedule 1 shows that the increase in average revenues is very nearly uniform, with slight differences due to rounding.

Q. **DID YOU COMPARE THE AMOUNT THAT CUSTOMERS WOULD PAY UNDER THE PRESENT AND PROPOSED RATES?**

A. Yes, the amounts that typical ratepayers can expect to pay under the proposed rates is compared to the amounts they would pay under the present rates on Exhibit No. __ (HSG-4), Schedule 2.

Q. **WHAT IS THE AMOUNT OF FUEL AND PURCHASED POWER COSTS INLCUDED IN THESE RATES?**

A. Fuel and Purchased Power in the Rate Year, representing the costs that are subject to the FAC, is $9,122,457, or 4.641 ¢/ kWh.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

Michael
Schussheim

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

DIRECT TESTIMONY OF MICHAEL SCHUSSHEIM

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Michael Schussheim. I am employed by the Incorporated Village of Rockville Centre (Village) as its Comptroller. My business address is 1 College Place, Rockville Centre, NY 11570.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. In September 1980, I received a bachelors degree in business administration from the Bernard M. Baruch College of the City University of New York. In August 1987, I became the Deputy Comptroller of the Village and the following year, I was promoted to Comptroller.

Q. PLEASE STATE ON WHOSE BEHALF YOU ARE TESTIFYING AND BRIEFLY DESCRIBE THE PURPOSES OF YOUR TESTIMONY.

A. I am testifying on behalf of the Village. My testimony will address the following:

- Support the Test Year historical data and Rate Year estimated expenses.
- Discuss the considerations in financing a planned capital addition (i.e., a new substation) and why the depreciable life for the substation should match the term of the debt.
- Estimate the cost of new debt.

TEST YEAR HISTORICAL DATA AND RATE YEAR ESTIMATED EXPENSES

Q. DID YOU REVIEW THE TEST YEAR HISTORICAL DATA INCLUDED IN THE TESTIMONY OF VILLAGE WITNESS GORMAN?

A. Yes, I reviewed the Test Year data in Exhibit No. __ (HSG-2, Schedules 1-7). The information on those schedules concerning sales, revenue, costs and rate base is taken from the Village's accounting and financial records, and is accurate and complete.

Q. DID YOU REVIEW THE RATE YEAR ESTIMATED EXPENSES INCLUDED IN MR. GORMAN'S TESTIMONY?

A. Yes, I reviewed the Rate Year estimated expenses in Exhibit No. __ (HSG-7, Schedules 1-13). Mr. Gorman's testimony explains how the Rate Year expenses were estimated, based on Test Year actual data and required adjustments. The judgments used in making these estimates are reasonable, and it is appropriate to use the estimated expenses shown in these schedules as the basis for the Rate Year revenue requirement.

CONSIDERATIONS IN FINANCING A PLANNED CAPITAL ADDITION

Q. HOW DOES THE VILLAGE PLAN TO FINANCE THE PLANNED ADDITION OF A SUBSTATION, DISCUSSED IN THE TESTIMONY OF VILLAGE WITNESS PALLAS?

A. The Village plans to issue long term debt to finance the substation.

Q. WHAT FACTORS DOES THE VILLAGE CONSIDER WHEN IT ISSUES DEBT?

A. The Village's considerations in issuing long-term debt are to maintain or improve its credit rating, to avoid over-burdening future residents, ratepayers and taxpayers and to minimize the aggregate cost of debt. To achieve these objectives, the Village usually issues debt with 15-year or shorter term final maturity. This helps achieve these objectives for the following reasons:

- Shorter maturities (i.e., 15 years compared to 30 years) means faster repayment, which means that less overall debt is outstanding. This increases the financial flexibility of the Village. Moody's has stated that the Village's low amounts of outstanding debt are an important factor in its AA3 credit rating. In July 2003, Moody's wrote:

  "Moody's expects the Village's debt position will remain manageable given its low direct debt burden, rapid payout of debt and lack of significant future debt plans. The Village's direct debt burden (exclusive of self-supporting debt) is a low 0.5% of full value and increases to an average 2.9% on an overall basis. Debt is amortized at a rapid rate, with 80.3% of principal retired in 10 years. Management reports limited future debt plans, including $5 million to finance the construction of an electric substation, which will not appreciably increase the debt burden."

  A copy of Moody's report is attached as Exhibit No. __ (MS-1). This favorable credit rating is an important factor in the Village obtaining attractive interest rates.

- Shorter maturities also means that debt is retired more quickly, and that the burden of repayment falls on those residents, ratepayers and taxpayers who benefit immediately, rather than in the future.

- Shorter maturities carry lower interest rates than longer maturities.

Therefore, it is the financial policy of the Village to issue debt with maturity of 15-years or less when possible.

Q. WHAT ALTERNATIVES ARE BEING CONSIDERED FOR DEBT THAT WILL BE ISSUED TO FINANCE THE NEW SUBSTATION?

A. The Village has obtained information from its financial advisor that 15-year debt would be required to yield 4.50%, while 30-year debt would be required to yield 5.25%. While the annual payments on 15-year debt are higher, the debt is retired much more quickly, and the total cost of financing is far lower. This is illustrated on Exhibit No. __ (MS-2), using the estimated debt issuance amount of $5 million. This shows that over 30 years, the cost of 15-year debt is $0.0346 / kWh, and the cost of 30-year debt is $0.0461 / kWh. Over 30 years, the average Residential customer will pay $352 with 15-year debt, and $469 with 30-year debt, an increase of 33%. Over 30 years, the average Commercial customer will pay $4,360 with 15-year debt, and $5,809 with 30-year debt, an increase of 33%.

Q. DOES THIS MEAN THAT THE VILLAGE INTENDS TO ISSUE 15-YEAR DEBT TO FINANCE THE SUBSTATION?

A. The Village intends to issue 15-year debt to finance the new substation.

Q. WHAT EFFECT DOES THIS HAVE ON THE RATE CASE?

A. The typical depreciable life for substation assets is 35.5 years. However, the Village is unable to issue debt for that maturity, and as discussed above, intends to issue 15-year debt. However, this would create a mismatch between depreciation expense and principal payments, with depreciation expense on the substation being insufficient to fund the principal payments on the assets. This will create cash flow pressures for the Village. The Village does not wish to alter its financial policy. Therefore, the depreciable life for the substation should be established at 15-years, to match the term of the associated debt and to support the Village's financial policy, which benefits the ratepayers and taxpayers.

ESTIMATED COST OF NEW DEBT

Q. WHAT IS THE APPROPRIATE COST OF NEW DEBT THAT SHOULD BE USED IN THIS PROCEEDING?

A. The cost of new debt should be 4.50%, provided that a 15-year depreciable life is used for the new substation asset. However, if a 35.5-year depreciable life is required for the substation, then depreciation will not be sufficient to cover principal payments on the new debt, and to make up this shortfall, the cost of new debt in this proceeding should be increased to 5.25%.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Michael Marks

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

DIRECT TESTIMONY OF MICHAEL MARKS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael Marks. My business address is 490 Wheeler Road, Suite 100, Hauppauge, New York 11788.

Q. PLEASE STATE YOUR QUALIFICATIONS RELATIVE TO THE TESTIMONY YOU ARE NOW PRESENTING.

A. I am a Senior Vice President and cofounder of Applied Energy Group, Inc. (AEG), having formed the company in 1982. AEG is a management and technical consulting firm that has served the electric and gas utility industry, both domestic and internationally, in areas of specialization that include load and energy forecasting; weather normalization studies; comparative economics studies of utility investments; and demand side management program assessment, implementation and evaluation.

Personally, I have been performing load forecasting and weather normalization studies for electric and gas utility clients since 1979. I began my professional career at American Electric Power as a Systems Load Analyst in the Load

Forecasting group. I have provided load forecasts for many electric and natural gas utilities over the past 20 years. I have a BS in Applied Mathematical Economics from SUNY Oswego and an MA in Applied Economics from SUNY Binghamton. I have taken a number of advanced courses in load forecasting over the past 15 years as well. A complete description of my qualifications and professional experience is contained in Exhibit No.___ (MM-1), my resume.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS?

A. I have testified as an expert witness on forecasting in the states of Connecticut, Kansas, South Carolina, Massachusetts, Texas, and Missouri. I have also provided expert testimony on demand side management issues in Kentucky and New Jersey. Exhibit No.____ (MM-1) contains the specific docket or case numbers for each of these states in which I testified.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

The purpose of my testimony is to present the results of a 15-year peak and energy forecast that I developed for Rockville Centre. This load forecast was included in an Integrated Resource Plan prepared by AEG (June 17, 2003) and is attached as Exhibit No. _____(MM-2). I will briefly described the methodology and present some summary results. I will also describe the system peak normalization analysis which I conducted. This analysis for a review of historical system peaks on a consistent probabilistic basis and, further, is used as a starting point for the peak forecast.

Q. PLEASE DESCRIBE THE FORECAST DEVELOPMENT PROCESS.

A. The load and energy forecast which I prepared for Rockville Centre uses both econometric and statistical modeling techniques. An econometric model is able to relate underlying causal factors such as income, electric price, economic conditions, seasonal variations and weather to the energy use within an electric system over time. Econometric techniques are used to statistically verify and reliably estimate those relationships by developing equations that explain a statistically significant percentage of the historical variation in load. In contrast, statistical techniques do not employ mathematical expressions of causal variables. Rather, these techniques "fit" either a linear or non-linear model through a data series using various expressions of time as the independent variables.

The process of developing an econometric load and energy forecast consists of three basic steps: (1) selecting the appropriate independent variables which influence the customer class demand for electricity that is the object of the investigation, (2) analyzing, using an array of statistical techniques, the quantitative historical relationships between the independent variables and actual electric use, and (3) forecasting the statistically and logically significant independent variables which, in turn, will produce a forecast for electric use. By disaggregating Rockville Centre's electric sales into its rate class segments, a more accurate forecast of electric sales can be developed using specific variable sets that best explain the variation in the historic electric sales for each of the rate classes.

Q. WHAT ANALYSIS PERIOD DID YOU USE FOR THE FORECAST MODELS?

A. Rockville Centre provided AEG with ten years of historical monthly kWh data for each customer group (i.e., October 1992 through September 2002). The historical data sets provided a sufficient history upon which to forecast future trends in electric sales by class. The historical data sets also supported all of the different statistical techniques utilized for forecasting the different classes, including multiple regression analysis, Cochrane-Orcutt procedures, exponential smoothing and Box Jenkins analysis. The aggregation of the monthly data into quarterly historical data sets provided sufficient information for regression analysis from a "degrees of freedom" perspective, (i.e., degrees of freedom equals the number of data observations less the number of estimated equational elements) while minimizing the potential problems associated with billing cycle issues in the data. The historical data series are also long enough to capture changes and variation in sales due to:

- The introduction of new end uses

- Changes in the intensity of use of all major end uses
- End use efficiency improvements resulting from normal replacement cycles

All models were initially structured with quarterly data sets. Quarterly data provides a more robust estimation of seasonal factors such as weather. Monthly data is more difficult to model because of irregularities due to billing cycle variations and/or customers dropping in and out of the various classes under study. By aggregating monthly data into quarterly data series, these irregularities can be "smoothed away". All of the models utilized in this load forecast were based upon quarterly data sets.

Q. PLEASE DESCRIBE THE HISTORICAL DATA THAT WAS COLLECTED FOR THE FORECAST MODELS.

A. The following data was collected for the load forecast:

1. Ten years of monthly kWh sales, number of customers and revenues for the following classes:
   - Residential
   - Commercial
   - Municipal
   - Public Authority
   - Street Lighting

2. Historical annual summer peaks (1995 – 2002) Ten years of weather variables (e.g., monthly heating and cooling degree days) for New York's John F. Kennedy Airport (this weather station is the closest weather station to the Rockville Centre service territory).
3. Daily summer weather data for the 1995 – 2002 period.
4. Ten years of regional indicators of economic growth and vitality such as income per household and employment for the Nassau County region.
5. Identification of any major customer additions/expansions and departures/reductions over the historical period or in the future that could impact load growth.
6. A list of any major events (such as a large customer installing cogeneration), which could have had a dramatic impact on electric sales over the past 10 years. Specifically, the load for an Apartment complex of approximately 1 MW of new load and an expansion for South Nassau Community hospital of 1.2 MW of additional load was considered.
7. An estimation of the impact of any past load management or conservation initiatives that could have affected Rockville Centre load growth.

Q. WHAT ECONOMETRIC FORECAST ASSUMPTIONS DID YOU EMPLOY?

A. To generate an econometric forecast, projections must be made for each of the explanatory variables. The forecasts for the economic variables were obtained in a number of ways. One important feature of the explanatory variables was that they were as representative of the Village as possible. Rockville Centre is located in Nassau County on Long Island. In order to insure that we had the best independent variables from which to select, we purchased a regionally appropriate economic indicator database with a companion expert forecast. This database provided our residential and commercial models with the economic drivers necessary to produce a fully causal model structure. Thus, a data set of historical and projected regional demographic and economic indicators was purchased from Economy.com. Economy.com is the web's most comprehensive source for professional economic research with hundreds of analytical and statistical reports covering a wide range of industry, macroeconomic, regional, and international topics. Historical and forecasted data was obtained for Nassau County and used in the econometric models. All price and economic driver variables were adjusted for inflation by using a New York Consumer Price Index as the implicit price deflator. All forecasts were expressed in real terms, so inflation was factored out of all forecast projections. Based upon model diagnostics and testing, Real Income Per Household was found to have the best statistical fit of the available economic indicator variables for the residential model and employment for the commercial model. The forecast for these two variables was obtained from Economy.com. This forecast was Nassau County specific. The real price of electricity (cost per kWh) was forecasted using a regression model of historical cost per kWh. Annual heating and cooling degree-days were forecasted to be normal (defined as the 30-year monthly average).

Q. WHAT WAS YOUR MODEL SELECTION CRITERIA?

A. There are always different model structures to choose from. Models can differ in many ways, including variable combinations, use of lag terms, use of different data periods (monthly versus quarterly), etc. AEG evaluated different models based upon a combination of the following criteria:

1. Residual analysis and traditional "goodness of fit" measures to determine how well these models fit the historical data and whether there were any statistical problems such as autocorrelation. The "goodness of fit" measures evaluated were as follows:
   - The Standard Error of the Estimate
   - Adjusted R-square
   - The Bayesian Information Criterion
   - The "t" values of the Partial Regression Coefficients
   - Durbin-Watson "d" or "f" Statistic for Autocorrelation
   - Ljung-Box Test for Autocorrelation
2. An analysis of the reasonableness of the forecast generated by the models. The criterion was whether there were any obvious anomalies, such as the forecasts exceeding all rational expectations based on historical trends and current industrial expectations.
3. An analysis of the reasonableness and sign of the coefficient for each of the explanatory variables.

4. The overall logic of the selected model as compared to accepted economic theory.

Q. PLEASE SUMMARIZE YOUR FINAL MODEL SELECTIONS FOR THE RESIDENTIAL AND COMMERCIAL CLASSES.

A. The final model selected for Residential sales utilized a quarterly data series over a ten-year period (1992 Q4 – 2002 Q3). The Residential model included quarterly cooling degree-days (heating degree days were found to be statistically insignificant), Real Income per Household, Real Price of Electricity, a 2nd Quarter Seasonal Dummy (the 1st and 3rd quarter seasonal dummies were statistically insignificant), an Autocorrelation Term (4 quarter) and an Intercept term.

The final model selected for Commercial sales utilized a quarterly data series over a ten-year period (1992 Q4 – 2002 Q3). The Commercial model included quarterly cooling degree-days (heating degree days were found to be statistical insignificant), Employment, a 2nd Quarter Seasonal Dummy (the 1st and 3rd quarter seasonal dummies were statistically insignificant), and an Intercept term. The real price of electricity was extensively tested in various models but was found to be statistically insignificant (although it did have the correct sign) and left out of the final model.

Q. HOW DID YOU FORECAST THE REMAINING THREE RATE CLASSES?

The remaining three rate classes make up only 3% of total system sales. Further, each of these classes is not expected to undergo any dramatic changes over the forecast horizon. For this reason, I focused on fitting the historical data with competent statistical models to project "persistence type" forecasts for these classes.

The Municipal class includes all Village facilities. The final model selected for Municipal sales utilized a quarterly data series over a ten-year period (1992 Q4 – 2002 Q3). The model included quarterly cooling degree days (heating degree days were found to be statistical insignificant), Households, a 1st Quarter Seasonal Dummy (the 2nd and 3rd quarter seasonal dummies were statistically insignificant), and an Intercept term. The Street Lighting class is comprised of streetlights throughout the Village. A Box Jenkins model was selected to forecast this class. The Public Authority class primarily includes pumping motor loads for the Rockville Centre Municipal Water system. An exponential smoothing model was selected for this class.

Q. WHAT WERE THE RESULTS OF THE ENERGY FORECAST?

A. Table 1 contains the historical data and 15-year energy forecasts for each of the different customer groups.

Table 1

	Year	Residential Sales Mwh	Commercial Sales Mwh	Other Sales Mwh	Total Sales Mwh
Historical	1993	76,311	88,948	5,390	170,650
Historical	1994	76,467	91,476	5,512	173,455
Historical	1995	77,106	92,527	5,508	175,142
Historical	1996	77,337	94,519	5,505	177,360
Historical	1997	77,994	93,775	5,404	177,173
Historical	1998	81,058	95,842	5,685	182,585
Historical	1999	84,790	98,001	5,661	188,452
Historical	2000	83,984	97,200	5,700	186,884
Historical	2001	83,624	96,762	5,785	186,171
Historical/Forecast	2002	89,205	97,950	5,829	192,984
Forecasted	2003	88,408	98,271	5,725	192,404
Forecasted	2004	90,606	98,782	5,736	195,124
Forecasted	2005	92,997	99,142	5,748	197,887
Forecasted	2006	95,463	103,558	5,759	204,780
Forecasted	2007	96,958	107,958	5,766	210,681
Forecasted	2008	98,780	108,233	5,777	212,790
Forecasted	2009	100,121	108,466	5,802	214,389
Forecasted	2010	100,484	108,762	5,826	215,071
Forecasted	2011	100,330	109,184	5,840	215,354
Forecasted	2012	100,139	109,607	5,855	215,601
Forecasted	2013	99,942	110,032	5,870	215,844
Forecasted	2014	99,748	110,459	5,886	216,093
Forecasted	2015	99,552	110,889	5,901	216,342
Forecasted	2016	99,407	111,321	5,916	216,643
Forecasted	2017	99,211	111,755	5,931	216,897

Residential kWh sales are forecasted to grow at a rate of 0.83%, compared to an historical growth rate of 1.15% during the 1993 through 2001 historical period.

Commercial kWh sales are forecasted to grow at a rate of 0.92%, compared to an historical growth rate of 1.06% during the 1993 through 2001 historical period.

Q. HOW DID YOU FORECAST SYSTEM PEAK DEMAND?

A. Summer peak demand was forecasted based upon the econometrically derived energy forecast and an assumed annual load factor. The annual load factor can be represented by the following equation:

Annual L.F. (%) = Annual Energy*100 / 8760 hours* Annual Peak Demand

In order to determine the load factor to be used with the energy forecast, I weather-normalized both historical sales system peaks over the 1995 – 2002 period. I then calculated load factors by year based upon normal weather. I then averaged the eight years to arrive at a weather normal load factor which could be applied against the energy forecast.

Table 2 illustrates the historical information used to derive the load factor estimate.

Table 2

	Actual Sales	Normalized Sales	Actual Peaks	Weather Normalized Peaks	Load Factor Actual Weather	Load Factor Weather Normalized
1995	175,141,678	171,987,462	44,260	45,022	44.36%	43.61%
1996	177,360,042	179,225,276	40,380	42,026	50.67%	48.68%
1997	177,172,772	177,521,556	44,941	42,582	45.09%	47.59%
1998	182,585,196	181,144,569	46,640	44,163	44.34%	46.82%
1999	188,452,034	185,874,069	50,459	43,942	42.05%	48.29%
2000	186,883,978	188,491,415	44,999	45,699	47.82%	47.08%
2001	186,171,414	184,958,254	48,840	47,027	43.23%	44.90%
2002	191,994,035	189,647,560	49,080	47,543	44.11%	45.54%
				Average	45.21%	46.56%

Table 3 contains the historical and forecasted system peaks

Table 3

	Year	Annual Sales	Summer Peak Demand	Load Factor
Forecasted	2003	192,404	47.17	46.56%
Forecasted	2004	195,124	47.84	46.56%
Forecasted	2005	197,887	48.51	46.56%
Forecasted	2006	204,780	50.20	46.56%
Forecasted	2007	210,681	51.65	46.56%
Forecasted	2008	212,790	52.17	46.56%
Forecasted	2009	214,389	52.56	46.56%
Forecasted	2010	215,071	52.73	46.56%
Forecasted	2011	215,354	52.80	46.56%
Forecasted	2012	215,601	52.86	46.56%
Forecasted	2013	215,844	52.92	46.56%
Forecasted	2014	216,093	52.98	46.56%
Forecasted	2015	216,342	53.04	46.56%
Forecasted	2016	216,643	53.11	46.56%
Forecasted	2017	216,897	53.17	46.56%
	Compound Growth Rate		0.86%	

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Exhibit No. ______
(PJP-1)

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

Exhibit No. __ (PJP-1)
Schedule 1

Fuel Adjustment / Reconciliation Current Method (Fiscal Year 2003 experience)

	KWH SALES	REVENUE W/O FUEL	FUEL ADJUST-MENT	REVENUE WITH FUEL	FUEL IN RATE BASE	TOTAL FUEL REVENUE	PURCH. ENERGY & CAPACITY	PASNY $	TOTAL PURCH. $	OIL AND GAS $	NYISO ANCIL-LARY $	TRANS. CON-GESTION	MONTHLY ADJUST-MENTS	TOTAL $	(UNDER) / OVER COL-LECTION
JUN	13,965,796	$963,592	$166,177	$1,129,769	$294,678	$460,855	$242,249	$370,048	$612,298	$91,755	$61,605	$58,267	$71,128	$778,517	($317,662)
JUL	18,769,789	$1,214,277	$368,909	$1,583,186	$396,043	$764,952	$391,392	$377,859	$769,251	$214,609	$89,557	$48,388	$47,603	$1,072,633	($307,681)
AUG	21,709,855	$1,338,232	$602,350	$1,940,582	$458,078	$1,060,428	$342,390	$420,477	$762,867	$197,666	$68,556	$42,144	$164,049	$1,150,994	($90,566)
SEP	20,956,127	$1,321,183	$655,603	$1,976,786	$442,174	$1,097,777	$299,910	$388,582	$688,492	$39,767	$51,378	$28,162	$30,597	$782,071	$315,706
OCT	16,626,691	$1,073,429	$488,268	$1,561,697	$350,823	$839,091	$140,512	$551,949	$692,461	$12,759	$53,755	$17,510	$11,052	$752,517	$86,574
NOV	13,507,645	$878,831	$376,712	$1,255,543	$285,011	$661,723	$99,177	$457,956	$557,133	$2,987	$42,032	$13,604	$33,147	$621,696	$40,028
DEC	14,506,373	$893,557	$380,293	$1,273,850	$306,084	$686,377	$172,396	$479,186	$651,582	$13,666	$33,963	$27,571	$18,676	$690,315	($3,938)
JAN	17,279,421	$1,053,255	$394,285	$1,447,540	$364,596	$758,881	$251,110	$493,532	$744,643	$20,574	$44,576	$60,311	($5,653)	$743,829	$15,052
FEB	16,081,553	$1,051,952	$379,532	$1,431,484	$339,321	$718,853	$200,708	$537,686	$738,394	$5,110	$50,348	$17,858	$19,027	$795,021	($76,168)
MAR	14,591,849	$918,381	$436,670	$1,355,051	$307,888	$744,558	$146,789	$586,866	$733,655	$20,388	$57,802	$71,033	$17,326	$758,138	($13,580)
APR	14,958,612	$954,619	$490,792	$1,445,411	$315,627	$806,419	$134,497	$500,966	$635,464	$22,981	$66,122	$46,966	$21,800	$699,401	$107,018
MAY	13,496,751	$854,094	$419,591	$1,273,685	$284,781	$704,372	$117,849	$447,915	$565,764	$22,205	$69,733	$101,276	($63,960)	$492,467	$211,906
	196,450,462	$12,515,402	$5,159,182	$17,674,584	$4,145,105	$9,304,287	$2,538,981	$5,613,021	$8,152,002	$664,467	$689,426	$533,089	$364,793	$9,337,598	($33,312)

Fuel Adjustment / Reconciliation Proposed Method (Data from FY 04 Forecast and FY 03 Actual)

	ESTIMATED KWH SALES	BASE FUEL REVENUE	ESTIMATED FUEL COST	EST-IMATED FUEL ADJUST-MENT RATE	EST-IMATED FUEL ADJUST-MENT $	ACTUAL KWH SALES	ACTUAL BASE FUEL REVENUE	FUEL ADJUST-MENT ACTUAL REVENUE	TOTAL ACTUAL FUEL REVENUE	ACTUAL FUEL COST	(UNDER) / OVER COL-LECTION	CUMUL-ATIVE (UNDER) / OVER COL-LECTION	RECONCIL-IATION RATE (TWO MONTH LAG)	RECONCIL-IATION CUMULATIVE RATE
JUN	13,507,228	$626,870	$872,737	$0.0182	$245,866	13,126,807	$609,215	$238,942	$848,157	$778,517	$69,639	$69,639	$0.0000	$0.0000
JUL	18,153,482	$842,503	$1,085,307	$0.0134	$242,804	18,565,157	$861,609	$248,310	$1,109,919	$1,072,633	$37,286	$106,925	$0.0000	$0.0000
AUG	20,997,011	$974,471	$1,051,178	$0.0034	$70,904	20,805,698	$965,592	$70,258	$1,035,850	$1,150,994	($115,143)	($8,218)	($0.0003)	($0.0003)
SEP	20,268,031	$940,639	$886,577	($0.0031)	($62,771)	18,968,752	$880,340	($58,747)	$821,593	$782,071	$39,521	$31,303	($0.0002)	($0.0004)
OCT	16,080,753	$746,308	$734,251	($0.0006)	($9,371)	16,626,691	$771,645	($9,689)	$761,956	$752,517	$9,439	$40,742	$0.0006	$0.0002
NOV	13,064,121	$606,306	$645,461	$0.0029	$38,044	13,507,645	$626,890	$39,335	$666,225	$621,696	$44,529	$85,272	($0.0003)	($0.0001)
DEC	14,030,055	$651,135	$734,889	$0.0058	$81,773	14,506,373	$673,241	$84,550	$757,790	$690,315	$67,475	$152,747	($0.0001)	($0.0001)
JAN	16,712,050	$775,606	$761,023	($0.0012)	($20,653)	17,279,421	$801,938	($21,354)	$780,584	$743,829	$36,755	$189,501	($0.0002)	($0.0004)
FEB	15,553,514	$721,839	$681,549	($0.0033)	($51,561)	16,081,553	$746,345	($53,312)	$693,033	$795,021	($101,988)	$87,514	($0.0004)	($0.0007)
MAR	14,112,725	$654,972	$640,014	($0.0020)	($28,248)	14,591,849	$677,208	($29,207)	$648,001	$758,138	($110,137)	($22,624)	($0.0002)	($0.0009)
APR	14,467,445	$671,434	$677,097	$0.0000	$538	14,958,612	$694,229	$556	$694,785	$699,401	($4,616)	($27,239)	$0.0006	($0.0004)
MAY	13,053,584	$605,817	$646,221	$0.0034	$44,958	13,496,751	$626,384	$46,484	$672,868	$562,467	$110,401	$83,162	$0.0007	$0.0003
JUN	13,507,228	$626,870	$872,737	$0.0186	$250,962	13,126,807	$609,215	$243,894	$853,109	$778,517	$74,592	$157,754	$0.0000	$0.0004
JUL	18,153,482	$842,503	$1,085,307	$0.0132	$240,453	18,565,157	$861,609	$245,906	$1,107,515	$1,072,633	$34,882	$192,636	($0.0005)	($0.0001)
AUG	20,997,011	$974,471	$1,051,178	$0.0035	$73,575	20,805,698	$965,592	$72,905	$1,038,497	$1,150,994	($112,496)	$10,500	($0.0003)	($0.0001)
SEP	20,268,031	$940,639	$886,577	($0.0028)	($56,885)	18,968,752	$880,340	($53,238)	$827,101	$782,071	$45,030	$18,244	($0.0001)	($0.0001)
12 MONTH TOTAL (JUNE-MAY)														
	190,000,000	$8,817,900	$9,416,306		$552,282	192,515,309	$8,934,635	$556,125	$9,490,760	$9,407,598				

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

Exhibit No. __ (PJP-1)
Schedule 3

Comparison Summary of Fuel adjustment/ Reconciliation Methods (Using FY 03 Data)

	ACTUAL KWH SALES	TOTAL FUEL REVENUE	TOTAL FUEL COST	CURRENT METHOD (UNDER) / OVER COL-LECTION	PROPOSED METHOD (UNDER) / OVER COL-LECTION
JUN	13,965,796	$460,855	$778,517	($317,662)	$69,639
JUL	18,769,789	$764,952	$1,072,633	($307,681)	$37,286
AUG	21,709,855	$1,060,428	$1,150,994	($90,566)	($115,143)
SEP	20,956,127	$1,097,777	$782,071	$315,706	$39,521
OCT	16,626,691	$839,091	$752,517	$86,574	$9,439
NOV	13,507,645	$661,723	$621,696	$40,028	$44,529
DEC	14,506,373	$686,377	$690,315	($3,938)	$67,475
JAN	17,279,421	$758,881	$743,829	$15,052	$36,755
FEB	16,081,553	$718,853	$795,021	($76,168)	($101,988)
MAR	14,591,849	$744,558	$758,138	($13,580)	($110,137)
APR	14,958,612	$806,419	$699,401	$107,018	($4,616)
MAY	13,496,751	$704,372	$492,467	$211,906	$110,401
	196,450,462	$9,304,287	$9,337,598		

Exhibit No. ______
(PJP-2)

Incorporated Village of Rockville Centre

Five Year Capital Plan

The following five year capital plan details projects that the Electric Department of the Village of Rockville Centre has developed. The plan includes major projects (those greater than $50,000) that will be performed by outside contractors. One exception to this are Feeder Conversions which will be completed with in-house forces. They are included here since they are part of the new substation project. As with any capital budget, projects in the out years may change as conditions dictate.

One important aspect of this plan is that there are no generation projects listed at this time. However, this does not mean that more generation is not contemplated. At the present time, the Village is in the beginning stages of evaluating our capacity needs. Although our recently completed Integrated Resource Plan discussed generation additions, two factors have caused this aspect of our capital plan to be delayed.

The first issue is new environmental regulations that may significantly impact the status of our existing generation facility. These regulations are not expected to be issued until the first quarter of 2004. The second issue concerning generation is the impact of the NYISO demand curve on our cost of purchased capacity and the amount of locational capacity required. Our intention is to study these issues over the next 12-18 months and develop a comprehensive capacity plan taking into account these two issues, and other factors as necessary.

Paul J. Pallas

9/24/03

Village of Rockville Centre Five Year Capital Plan Details

Electric Department

Fiscal Year	Project	Estimate
2004-2005	New Substation 2-20MVA 35kv/4kv	$5,000,000
	SCADA System Replacement	150,000
	Vehicle Replacement	60,000
	Distribution Office Renovation	60,000
	Total FY '05	$5,270,000
2005-2006	South Nassau Hospital	500,000
	Feeder Conversion	100,000
	Line Truck	150,000
	Exterior building Renovation	2,500,000
	Total FY '06	$3,250,000
2006-2007	Power Plant Office Renovation	100,000
	Feeder Conversion	100,000
	Peninsula Blvd. Street Lights	1,000,000
	Total FY '07	$1,200,000

2007-2008	Bucket Truck	150,000
	Feeder Conversion	100,000
	Parking Lot Renovation	500,000
	Total FY '08	$ 750,000
2008-2009	Merrick Road Conduits	350,000
	Feeder Conversion	100,000
	Total FY '09	450,000

Village of Rockville Centre – Five Year Capital Plan
Project Descriptions

New Substation/Feeder Conversion

This project as described in the Integrated Resource Plan will provide greater access to market-based energy and improve distribution reliability. The project will install a new transmission substation at 33kv interconnected with an existing 33kv LIPA-owned transmission line. The LIPA-owned transmission line will require reconductoring to accommodate the new substation load. Two 20MVA 33kv/4kv substation transformers will be installed along with new distribution switchgear that will have two line circuit breakers, a bus tie circuit breaker and a minimum of 10 distribution circuit breakers. The substation will provide two important benefits. First, it will allow greater access to market-based energy which is currently capped at approximately 30MWs due to Rockville Centre transmission limitations. By adding this substation we will be able to import approximately up to our peak load when this is the most economic option.

The second benefit is the ability to move cables from existing circuit breakers that currently have two or three circuits connected. During cable failures uninvolved circuits are impacted when the circuit breaker trips. By reducing the number of cables attached to the circuit breakers we will minimize the impact of outages and aid in the troubleshooting process. This will improve reliability.

SCADA System Replacement

The existing SCADA system was installed in 1993 and is past its useful life. Extensive repairs over the last several years indicate the system no longer functions as originally designed. A new system will also provide better real time data that will allow greater operational flexibility in the deregulated wholesale market.

Vehicle Replacement

This project will replace one passenger vehicle and two vans that have reached the end of their useful lives.

Distribution Office

The distribution office has not been upgraded in over 25 years. This project will replace floors, walls and furniture as necessary.

South Nassau Hospital

This project will install a second dedicated distribution circuit to supply this critical facility. The hospital is embarking on a major expansion that will add over one megawatt to the existing load of just over two megawatts. The existing dedicated circuit does not have the capacity to supply the new load plus the existing load. The potential exists that if the Village cannot supply the new load the facility may seek other resources.

Line Trucks

The existing line truck is over twenty years old and requires replacement.

Existing Building Renovation

The exterior of all buildings located at the power plant site have deteriorated due to water infiltration behind the façade. In addition, all the windows in the power plant building require replacement. The building was constructed and modified at various times starting in the 1930's, with the latest addition constructed in the 1960's. The window replacement will provide improved ventilation in the power plant which will improve personnel comfort and equipment operability. The site consists of three buildings: Power Plant, Switchgear and Office. The Power Plant building houses eight engine generators as well as the control room for the plant and distribution facility. Many areas have loose bricks on the façade and the parapet wall coping requires resetting on the entire structure. The windows in this structure are of an old style and many panes are loose. Every window will require removal, renovation and reinstallation. The switchgear building and office building are in similar states although no window replacements are required.

Power Plant Office Renovation

Similar in nature to the distribution office with the additional work of renovating the power plant operators booth which is located on the engine room floor.

Peninsula Blvd. Street Lights

There is a large section of this major county road that runs through the Village that currently has no street lights. By county rules, the Village is responsible for installing street lights on county roads within the Village boundary. This project will improve visibility along this well traveled road. Traditionally, the electric department has funded all street lighting installations within the Village.

Bucket Truck

One of the fleet of bucket trucks will require replacement as it will have reached the end of its useful life. This vehicle will be over 20 years old.

Parking Lot Renovation

This project improves all paved areas within the electric department facility. Large areas of the parking lot are uneven which creates drainage problems and potential safety hazards.

Merrick Road Conduits

This project will install conduit crossings across Merrick Road, one of the largest east-west roads in the Village. Currently, there are limited available crossings. This project will improve our ability to install new cables in the event of an existing cable failure or new load requirements.

Exhibit No. ______
(HSG-1)

INCORPORATED VILLAGE OF ROCKVILLE CENTRE
INDEX TO EXHIBIT NO. __ TO __ (HSG-2 TO HSG-7)
Test Year Ended May 31, 2003
Rate Year Ended May 31, 2005

INCORPORATED VILLAGE OF ROCKVILLE CENTRE
INDEX TO EXHIBIT NO. __ TO __ (HSG-2 TO HSG-7)
Test Year Ended May 31, 2003
Rate Year Ended May 31, 2005

Exhibit No. ______
(HSG-2)

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

SUMMARY OF ELECTRIC SALES, CUSTOMERS AND REVENUE
ALL SERVICE CLASSIFICATIONS
Test Year Ended May 31, 2003

			Revenue - Present Rates			Revenue per Customer	Revenue per kWh
	Sales (kWh)	Average Customers	Base Rates	Fuel Clause	Total	Present Rates	Present Rates
SC 1- General Services - Small	2,824,120	334	$ 220,513	$ 74,688	$ 295,201	$ 884	$ 0.10453
SC 3- Residential	90,048,045	8,801	5,859,738	2,357,966	8,217,704	934	0.09126
SC 3- Residential / Space Heating	2,168,621	131	131,769	56,607	188,376	1,438	0.08686
Total SC 3- Residential	92,216,666	8,932	5,991,507	2,414,573	8,406,080	2,372	0.09116
SC 5- General Services - Large	95,509,145	764	5,778,616	2,484,825	8,263,441	10,812	0.08652
Street Lighting	3,219,416	1	179,784	84,571	264,355	264,355	0.08211
Operating Municipality	2,187,063	37	141,999	56,654	198,653	5,369	0.09083
Public Authorities	494,052	10	37,160	12,849	50,009	5,001	0.10122
Rounding			93,444		93,444		
TOTAL	196,450,462	10,078	$ 12,443,023	$ 5,128,160	$ 17,571,183	$ 1,743	$ 0.08944

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

SUMMARY OF ELECTRIC SALES, CUSTOMERS AND REVENUE
Service Classification 3 - Residential
Test Year Ended May 31, 2003

	Sales (kWh)	Bills Rendered	Revenue - Present Rates: Base Rates	Fuel Clause	Total
June 2002	6,253,250	4,410	$ 406,278	$ 74,407	$ 480,685
July 2002	8,134,454	4,435	546,112	159,875	705,987
August 2002	10,517,872	4,416	701,680	291,818	993,498
September 2002	10,322,147	4,437	689,083	322,928	1,012,011
October 2002	8,187,246	4,413	541,215	240,435	781,650
November 2002	6,163,111	4,440	395,420	171,883	567,303
December 2002	6,406,468	4,397	409,831	167,952	577,783
January 2003	7,550,448	4,419	478,537	172,286	650,823
February 2003	7,843,830	4,388	496,021	185,114	681,135
March 2003	6,332,525	4,434	405,551	185,017	590,568
April 2003	6,776,550	4,314	431,553	217,656	649,209
May 2003	5,560,144	4,305	358,457	168,595	527,052
TOTAL	90,048,045	52,808	$ 5,859,738	$ 2,357,966	$ 8,217,704
Average Customers		8,801			

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

SUMMARY OF ELECTRIC SALES, CUSTOMERS AND REVENUE
Service Classification 3 - Residential / Space Heating
Test Year Ended May 31, 2003

	Sales (kWh)	Bills Rendered	Revenue - Present Rates Base Rates	Revenue - Present Rates Fuel Clause	Revenue - Present Rates Total
June 2002	181,351	101	$ 11,645	$ 2,158	$ 13,803
July 2002	55,371	29	3,710	1,088	4,798
August 2002	216,601	100	14,470	6,010	20,480
September 2002	73,856	30	4,921	2,311	7,232
October 2002	211,770	101	13,817	6,219	20,036
November 2002	55,124	30	3,362	1,537	4,899
December 2002	224,803	100	13,489	5,893	19,382
January 2003	149,424	30	8,530	3,410	11,940
February 2003	405,897	101	23,395	9,579	32,974
March 2003	180,679	31	10,246	5,279	15,525
April 2003	321,282	101	18,752	10,319	29,071
May 2003	92,463	32	5,432	2,804	8,236
TOTAL	2,168,621	786	$ 131,769	$ 56,607	$ 188,376
Average Customers		131			

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

SUMMARY OF ELECTRIC SALES, CUSTOMERS AND REVENUE
Service Classification 1 - General Service - Small
Test Year Ended May 31, 2003

	Sales (kWh)	Bills Rendered	Revenue - Present Rates: Base Rates	Revenue - Present Rates: Fuel Clause	Revenue - Present Rates: Total
June 2002	195,786	324	$ 16,107	$ 2,330	$ 18,437
July 2002	225,101	323	18,396	4,424	22,820
August 2002	271,696	323	22,039	7,538	29,577
September 2002	230,536	326	18,828	7,212	26,040
October 2002	198,503	327	15,265	5,829	21,094
November 2002	236,097	329	18,008	6,585	24,593
December 2002	207,859	334	15,963	5,449	21,412
January 2003	240,704	336	18,360	5,492	23,852
February 2003	229,716	341	17,572	5,421	22,993
March 2003	193,844	341	14,960	5,664	20,624
April 2003	402,613	344	30,172	12,932	43,104
May 2003	191,665	358	14,843	5,812	20,655
TOTAL	2,824,120	4,006	$ 220,513	$ 74,688	$ 295,201
Average Customers		334			

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

SUMMARY OF ELECTRIC SALES, CUSTOMERS AND REVENUE
Service Classification 5 - General Service - Large
Test Year Ended May 31, 2003

	Sales (kWh)	Bills Rendered	Revenue - Present Rates: Base Rates	Fuel Clause	Total
June 2002	6,909,357	750	$ 426,293	$ 82,214	$ 508,507
July 2002	9,845,485	736	588,308	193,503	781,811
August 2002	10,193,300	743	577,486	282,813	860,299
September 2002	9,837,352	749	557,682	307,762	865,444
October 2002	7,526,616	755	456,724	221,034	677,758
November 2002	6,580,400	758	421,946	183,521	605,467
December 2002	6,943,843	760	425,781	182,040	607,821
January 2003	8,938,910	771	524,635	203,968	728,603
February 2003	7,100,454	774	453,189	167,571	620,760
March 2003	7,399,337	775	450,318	216,186	666,504
April 2003	7,015,349	778	440,750	225,326	666,076
May 2003	7,218,742	822	455,504	218,887	674,391
TOTAL	95,509,145	9,171	$ 5,778,616	$ 2,484,825	$ 8,263,441
Average Customers		764			

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

SUMMARY OF ELECTRIC SALES, CUSTOMERS AND REVENUE
Street Lighting (Service Classification 5 Applies)
Test Year Ended May 31, 2003

			Revenue - Present Rates		
	Sales (kWh)	Bills Rendered	Base Rates	Fuel Clause	Total
June 2002	201,408	1	$ 12,013	$ 2,397	$ 14,410
July 2002	209,768	1	12,384	4,123	16,507
August 2002	240,423	1	13,745	6,671	20,416
September 2002	254,608	1	14,375	7,965	22,340
October 2002	295,648	1	16,197	8,682	24,879
November 2002	312,368	1	16,939	8,712	25,651
December 2002	338,968	1	18,120	8,886	27,006
January 2003	333,353	1	17,870	7,606	25,476
February 2003	284,248	1	15,691	6,708	22,399
March 2003	285,768	1	15,758	8,349	24,107
April 2003	243,208	1	13,869	7,812	21,681
May 2003	219,648	1	12,823	6,660	19,483
TOTAL	3,219,416	12	$ 179,784	$ 84,571	$ 264,355
Average Customers		1			

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

SUMMARY OF ELECTRIC SALES, CUSTOMERS AND REVENUE
Operating Municipality (Service Classification 5 Applies)
Test Year Ended May 31, 2003

	Sales (kWh)	Bills Rendered	Revenue - Present Rates: Base Rates	Fuel Clause	Total
June 2002	183,473	37	$ 11,887	$ 2,183	$ 14,070
July 2002	258,439	37	15,215	5,079	20,294
August 2002	228,792	37	13,899	6,348	20,247
September 2002	196,457	37	12,464	6,146	18,610
October 2002	165,737	37	11,100	4,867	15,967
November 2002	119,374	37	9,042	3,329	12,371
December 2002	343,261	37	18,980	8,999	27,979
January 2003	25,411	37	4,871	580	5,451
February 2003	176,237	37	11,566	4,159	15,725
March 2003	158,525	37	10,780	4,632	15,412
April 2003	158,439	37	10,776	5,089	15,865
May 2003	172,918	37	11,419	5,243	16,662
TOTAL	2,187,063	444	$ 141,999	$ 56,654	$ 198,653
Average Customers		37			

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

SUMMARY OF ELECTRIC SALES, CUSTOMERS AND REVENUE
Public Authorities (Service Classification 1 Applies)
Test Year Ended May 31, 2003

			Revenue - Present Rates		
	Sales (kWh)	Bills Rendered	Base Rates	Fuel Clause	Total
June 2002	41,171	10	$ 3,244	$ 490	$ 3,734
July 2002	41,171	10	3,244	809	4,053
August 2002	41,171	10	3,244	1,142	4,386
September 2002	41,171	10	3,244	1,288	4,532
October 2002	41,171	10	3,023	1,209	4,232
November 2002	41,171	10	3,023	1,148	4,171
December 2002	41,171	10	3,023	1,079	4,102
January 2003	41,171	10	3,023	939	3,962
February 2003	41,171	10	3,023	972	3,995
March 2003	41,171	10	3,023	1,203	4,226
April 2003	41,171	10	3,023	1,322	4,345
May 2003	41,171	10	3,023	1,248	4,271
TOTAL	494,052	120	$ 37,160	$ 12,849	$ 50,009
Average Customers		10			

INCORPORA[illegible] VILLAGE OF ROCKVILLE CENTRE

Exhibit No. __ (HSG-2)
Schedule 3
Page 1 of 2

DETAIL OF BILLING UNITS AND RATES
Test Year Ended May 31, 2003- Present Rates

Rate Schedule		Residential-Spec. Prov. A SC-3A	Residential-Others SC-3	Commercial-Small SC-1	Commercial-Large SC-5	Street Lighting SC-5	Operating Municipality SC-5	Public Authorities SC-1	Total
		BILLING UNITS							
		kWh Sales Test Year Ended May 31, 2003							
June	Summer	181,351	6,253,250	195,786	6,909,357	201,408	183,473	41,171	13,965,796
July	Summer	55,371	8,134,454	225,101	9,845,485	209,768	258,439	41,171	18,769,789
August	Summer	216,601	10,517,872	271,696	10,193,300	240,423	228,792	41,171	21,709,855
September	Summer	73,856	10,322,147	230,536	9,837,352	254,608	196,457	41,171	20,956,127
October	Winter	211,770	8,187,246	198,503	7,526,616	295,648	165,737	41,171	16,626,691
November	Winter	55,124	6,163,111	236,097	6,580,400	312,368	119,374	41,171	13,507,645
December	Winter	224,803	6,406,468	207,859	6,943,843	338,968	343,261	41,171	14,506,373
January	Winter	149,424	7,550,448	240,704	8,938,910	333,353	25,411	41,171	17,279,421
February	Winter	405,897	7,843,830	229,716	7,100,454	284,248	176,237	41,171	16,081,553
March	Winter	180,679	6,332,525	193,844	7,399,337	285,768	158,525	41,171	14,591,849
April	Winter	321,282	6,776,550	402,613	7,015,349	243,208	158,439	41,171	14,958,612
May	Winter	92,463	5,560,144	191,665	7,218,742	219,648	172,918	41,171	13,496,751
		2,168,621	90,048,045	2,824,120	95,509,145	3,219,416	2,187,063	494,052	196,450,462

		Residential-Spec. Prov. A SC-3A	Residential-Others SC-3	Commercial-Small SC-1	Commercial-Large SC-5	Street Lighting SC-5	Operating Municipality SC-5	Public Authorities SC-1	Total
		Number of Bills Test Year Ended May 31, 2003							
June		101	4,410	324	750	1	37	10	5,633
July		29	4,435	323	736	1	37	10	5,571
August		100	4,416	323	743	1	37	10	5,630
September		30	4,437	326	749	1	37	10	5,590
October		101	4,413	327	755	1	37	10	5,644
November		30	4,440	329	758	1	37	10	5,605
December		100	4,397	334	760	1	37	10	5,639
January		30	4,419	336	771	1	37	10	5,604
February		101	4,388	341	774	1	37	10	5,652
March		31	4,434	341	775	1	37	10	5,629
April		101	4,314	344	778	1	37	10	5,585
May		32	4,305	358	822	1	37	10	5,565
		786	52,808	4,006	9,171	12	444	120	67,347
Monthly Demand kW						768	960		

Exhibit No. __ (HSG-2)
Schedule 3
Page 2 of 2

DETAIL OF BILLING UNITS AND RATES
Test Year Ended May 31, 2003- Present Rates

Rate Schedule		Residential- Spec. Prov. A SC-3A	Residential- Others SC-3	Commercial- Small SC-1	Commercial- Large SC-5	Street Lighting SC-5	Operating Municipality SC-5	Public Authorities SC-1	Total
RATES AND CHARGES									
Tariff Rates									
Customer Charge		$4.92	$4.92	$2.45				$2.45	
Energy Charge 1- Sum	Summer	$0.0611	$0.0611	$0.0774	$0.0519	$0.0519	$0.0519	$0.0774	
Energy Charge 1- Wint	Winter	$0.0611	$0.0611	$0.0721	$0.0519	$0.0519	$0.0519	$0.0721	
Energy Charge 2- Sum	Summer	$0.0647	$0.0647		$0.0440	$0.0440	$0.0440		
Energy Charge 2- Wint	Winter	$0.0594	$0.0594		$0.0440	$0.0440	$0.0440		
Energy Charge 3- Sum	Summer	$0.0647							
Energy Charge 3- Wint	Winter	$0.0541							
Demand- Secondary					$3.65	$3.65	$3.65		
Demand- High Tension					$3.11	$3.11			
Effective Rates with Gross Utility Tax									
Gross Utility Tax Multiplier		1.01010	1.01010	1.01010	1.008750	1.01010	1.01010	1.01010	
Customer Charge		$4.97	$4.97	$2.47				$2.47	
Energy Charge 1- Sum	Summer	$0.06172	$0.06172	$0.07818	$0.05235	$0.05242	$0.05242	$0.07818	
Energy Charge 1- Wint	Winter	$0.06172	$0.06172	$0.07283	$0.05235	$0.05242	$0.05242	$0.07283	
Energy Charge 2- Sum	Summer	$0.06535	$0.06535		$0.04439	$0.04444	$0.04444		
Energy Charge 2- Wint	Winter	$0.06000	$0.06000		$0.04439	$0.04444	$0.04444		
Energy Charge 3- Sum	Summer	$0.06535							
Energy Charge 3- Wint	Winter	$0.05465							
Demand- Secondary					$3.68	$3.69	$3.69		
Demand- High Tension					$3.14	$3.14			

Monthly Effective kWh Rates

		Residential- SC 3 and SC 3A			Sm. Comm.- SC 1	Large Commercial- SC 5	
		Block 1 Rate	Block 2 Rate	Block 3 Rate		Block 1 Rate	Block 2 Rate
June	Summer	$0.0617	$0.0613	$0.0573	$0.0782	$0.0524	$0.0444
July	Summer	$0.0617	$0.0654	$0.0654	$0.0782	$0.0524	$0.0444
August	Summer	$0.0617	$0.0654	$0.0654	$0.0782	$0.0524	$0.0444
September	Summer	$0.0617	$0.0654	$0.0654	$0.0782	$0.0524	$0.0444
October	Winter	$0.0617	$0.0640	$0.0627	$0.0728	$0.0524	$0.0444
November	Winter	$0.0617	$0.0600	$0.0547	$0.0728	$0.0524	$0.0444
December	Winter	$0.0617	$0.0600	$0.0547	$0.0728	$0.0524	$0.0444
January	Winter	$0.0617	$0.0600	$0.0547	$0.0728	$0.0524	$0.0444
February	Winter	$0.0617	$0.0600	$0.0547	$0.0728	$0.0524	$0.0444
March	Winter	$0.0617	$0.0600	$0.0547	$0.0728	$0.0524	$0.0444
April	Winter	$0.0617	$0.0600	$0.0547	$0.0728	$0.0524	$0.0444
May	Winter	$0.0617	$0.0600	$0.0547	$0.0728	$0.0524	$0.0444

Exhibit No. __ (HSG-2)
Schedule 4

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

RATE OF RETURN ON RATE BASE
Test Year Ended May 31, 2003

	ACTUAL
OPERATING REVENUE	
Sales of Electricity	$ 17,571,183
Street Lighting Rental	159,996
Misc Other Revenue	4,545
Interest Income	73,857
Other Electric Income	2,004,197
	19,813,778
OPERATING EXPENSES	
Electric Production:	
Generation Costs	1,476,281
Fuel for Generation	664,467
Other Production Expense	440,179
Purchased Electricity	8,504,755
	11,085,682
Transmission	100,377
Distribution	559,166
Street Lighting	299,535
Customer Accounts	362,805
General & Administrative	1,865,284
Depreciation Expense	1,243,209
Special Contract Expense	2,000,000
Tax Equivalency	1,624,411
Gross Utility Tax	165,653
Uncollectible Accounts	25,529
	19,331,651
NET ELECTRIC OPERATING INCOME	$ 482,127
RATE BASE	$ 23,455,484
RATE OF RETURN ON RATE BASE	2.06%

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

COMPUTATION OF RATE BASE
Test Year Ended May 31, 2003

	Balance, May 31, 2003	Balance, May 31, 2002	Average
Utility Plant in Service			
Assets	$ 42,966,248	$ 40,412,140	$ 41,689,194
Construction Work in Progress	1,100,042	3,345,179	2,222,611
Less: Contributions for Extensions	(1,555,526)	(1,555,526)	(1,555,526)
Less: Accumulated Depreciation	(22,357,836)	(22,357,836)	(22,357,836)
	20,152,928	19,843,957	19,998,443
Materials & Supplies	1,640,854	1,705,016	1,672,935
			21,671,378
Cash Working Capital Allowance			1,784,106
RATE BASE			$ 23,455,484
Cash Working Capital Allowance:			
Operating Expenses, Test Year			$ 19,331,651
Deductions:			
Fuel for Generation			664,467
Purchased Electricity			8,504,755
Depreciation Expense			1,243,209
Contract Expense			2,000,000
Tax Equivalency			1,624,411
Gross Utility Tax			165,653
Uncollectible Accounts			25,529
Total Deductions			14,228,024
Cash Operating Expenses			5,103,627
Cash Operating Expenses Ratio			1/8
Cash Operating Expenses Allowance (A)			637,953
Fuel for Generation			664,467
Purchased Electricity			8,504,755
Cash Fuel and Purchased Power Expenses			9,169,222
Cash Fuel and Purchased Power Ratio			1/12
Cash Fuel and Purchased Power Allowance (B)			1,146,153
Cash Working Capital Allowance (A plus B)			$ 1,784,106

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

Exhibit No. __ (HSG-2)
Schedule 6
Page 1 of 2

OPERATING EXPENSE DETAILS - ACTUAL
Test Year Ended May 31, 2003

Account Number	Description	Total	Production Expenses	Transmission Expenses	Maintenance- Poles	Distribution Expenses	St Light Expenses	Customer Accounts	General & Administrative	Non-Operating Expense
111	Regular Time	1,852,667	989,100	4,224		323,540	119,515	111,641	304,647	
112	Overtime	153,309	51,797	1,400		58,330	39,528	1,313	941	
115	Seasonal	485				25		460	0	
410	Supplies & Materials	176,054	69,340	1,433	1,934	22,651	30,221	264	50,211	
431	Telephone	24,557	633						23,924	
433	Water	19,047	19,047							
441	Publicity	4,368							4,368	
451	Printing	2,665				173		310	2,182	
452	Rentals	93,641	3,624	89,666		12			339	
455	Medical Fees	1,026							1,026	
459	Data Processing	13,983				636		9,290	4,057	
465	Insurance	164,122							164,122	
471	Postage	25,415						25,383	32	
472	Dues	4,283							4,283	
473	Travel	11,273							11,273	
474	Outside Legal	14,008							14,008	
475	Subscriptions	18,532							18,532	
476	Regulatory / PSC Expense	46,358							46,358	
477	Legal Notices	137							137	
478	MEUA Expenses	11,171							11,171	
484	Contract Services	2,460,394	2,440,179			2,755		8,491	8,969	
492	Professional Services	44,720							44,720	
495-498	Purchased Power	8,504,755	8,504,755							
608	Merchandise & Jobbing	(5,790)			(649)	(3,400)	(1,741)			
610	Material from Inventory	100,014	53,009			8,938	38,054	7	6	
620	Fuel Oil for Generation	207,934	207,934							
621	Natural Gas for Generation	456,533	456,533							
630	Ammonia from Inventory	1,127	1,127							
660	Inventory Overhead	51,526	22,791			5,452	23,237	42	4	
665	Depreciation	1,243,209	519,097	120,649	92,588	314,967	92,681		103,227	
670	Work Orders	(17,861)			649	7,142	(7)		(25,645)	
724	Payroll Reimb. Oper Munic.	585,076						137,840	447,236	
804	Transportation	82,023	6,990	386		32,062	12,553	15,990	14,042	
805	Building Services	39,067				7,813		23,441	7,813	
901	Tax Equivalency	1,624,411								1,624,411
902	Gross Utility Tax	165,653								165,653
903	A/R Consumers Bad Debt Exp	25,529								25,529
912	Consumers Deposit Interest	1,957							1,957	
929-939	Bond Interest	489,890								489,890
950	Expense Recovery	14,536							14,536	

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - ACTUAL
Test Year Ended May 31, 2003

Account Number	Description	Total	Production Expenses	Transmission Expenses	Maintenance- Poles	Distribution Expenses	St Light Expenses	Customer Accounts	General & Administrative	Non-Operating Expense
800	Employee Benefits	496,294	258,823	1,334		93,037	38,175	28,333	76,592	
810	Retirement	36,584							36,584	
820	FICA	134,322							134,322	
830	Workers Compensation	31,196							31,196	
850	Dental / Medical	407,271							407,271	
860	Life Insurance	4,069							4,070	
	TOTALS	19,821,540	13,604,779	219,092	94,522	874,133	392,216	362,805	1,968,511	2,305,483
	Depreciation Expense	1,243,209	519,097	120,649	92,588	314,967	92,681	0	103,227	0
	Totals Without Depreciation	18,578,331	13,085,682	98,443	1,934	559,166	299,535	362,805	1,865,284	2,305,483

Production Expense	
Generation Costs	1,476,281
Fuel Generation	664,467
Purchased Electricity	8,504,755
Other Production Expense	440,179
Special Contract Expense	2,000,000
	13,085,682

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

GROSS UTILITY TAX MULTIPLIERS
Test Year Ended May 31, 2003

General	
Gross Utility Tax Rate	1.00%
Gross Utility Tax Multiplier	1.01010

Per General Information XX-A of the Tariff, Leaf 11C-1, Rates and Charges for all sales are grossed up for applicable taxes. The Gross Utility Tax rate for sales of electricity within the Village is 1.0%.

Large Commercial under SC-5	
Large Commercial Revenue outside Village	$1,109,221
Total Large Commercial Revenue	8,268,922
% Large Commercial Revenue outside Village	13.41%
Gross Utility Tax Multiplier (No Gross Utility Tax applies)	1.00000
% Large Commercial Revenue outside Village	86.59%
Gross Utility Tax Multiplier	1.01010
Overall Gross Utility Tax Multiplier for Large Commercial	1.00875

Exhibit No. ______
(HSG-3)

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

ELECTRIC PRODUCTION COSTS IN FUEL ADJUSTMENT CLAUSE

Uses and Soures of kWh

	KWh Sales	Station kWh	Lost & Unaccounted kWh	Total Uses of kWh	PASNY kWH	Oil kWh	Gas kWH	Purchased kWh	Total Sources of kWh
	Test Year Ended May 31, 2003								
Column	A	B	C	D	E	F	G	H	I
Source	=HSG-1, Sch3	Input	=D-A-B	=I	Input	Input	Input	Input	=Sum(E:H)
June	13,965,796	134,000	4,856,204	18,956,000	12,157,000	527,000	1,184,000	5,088,000	18,956,000
July	18,769,789	230,000	4,795,211	23,795,000	11,907,000	642,000	3,352,000	7,894,000	23,795,000
August	21,709,855	209,000	1,327,145	23,246,000	13,524,000	476,000	3,238,000	6,008,000	23,246,000
September	20,956,127	116,000	(2,689,127)	18,383,000	12,391,000	200,000	492,000	5,300,000	18,383,000
October	16,626,691	114,000	(472,691)	16,268,000	14,526,000	24,000	139,000	1,579,000	16,268,000
November	13,507,645	115,000	1,743,355	15,366,000	14,610,000	0	0	756,000	15,366,000
December	14,506,373	173,000	2,780,627	17,460,000	14,915,000	237,000	0	2,308,000	17,460,000
January	17,279,421	182,000	502,579	17,964,000	14,398,000	304,000	0	3,262,000	17,964,000
February	16,081,553	161,000	(867,553)	15,375,000	13,579,000	47,000	0	1,749,000	15,375,000
March	14,591,849	145,000	1,106,151	15,843,000	15,034,000	287,000	7,000	515,000	15,843,000
April	14,958,612	126,000	(560,612)	14,524,000	13,301,000	110,000	149,000	964,000	14,524,000
May	13,496,751	108,000	1,331,249	14,936,000	13,128,000	123,000	177,000	1,508,000	14,936,000
	196,450,462	1,813,000	13,852,538	212,116,000	163,470,000	2,977,000	8,738,000	36,931,000	212,116,000
	Average Lost and Unaccounted		6.9869%						

	Rate Year Ended May 31, 2005								
Column	a	b	c	d	e	f	g	h	i
Source	=HSG-4, Sch3	Same as Test Year	=TY Avg *(a+b)	=Sum(a:b)	Same as Test Year	Same as Test Year	Same as Test Year	=d-Sum(e:g)	=Sum(e:h)
June	15,873,567	134,000	1,118,433	17,126,000	12,157,000	527,000	1,184,000	3,258,000	17,126,000
July	18,305,620	230,000	1,295,065	19,830,685	11,907,000	642,000	3,352,000	3,929,685	19,830,685
August	20,467,130	209,000	1,444,621	22,120,751	13,524,000	476,000	3,238,000	4,882,751	22,120,751
September	19,724,520	116,000	1,386,237	21,226,757	12,391,000	200,000	492,000	8,143,757	21,226,757
October	17,203,953	114,000	1,209,988	18,527,941	14,526,000	24,000	139,000	3,838,941	18,527,941
November	14,451,766	115,000	1,017,765	15,584,531	14,610,000	0	0	974,531	15,584,531
December	14,966,948	173,000	1,057,813	16,197,761	14,915,000	237,000	0	1,045,761	16,197,761
January	15,874,381	182,000	1,121,843	17,178,224	14,398,000	304,000	0	2,476,224	17,178,224
February	15,911,839	161,000	1,122,993	17,195,832	13,579,000	47,000	0	3,569,832	17,195,832
March	14,829,724	145,000	1,046,269	16,020,993	15,034,000	287,000	7,000	692,993	16,020,993
April	14,926,528	126,000	1,051,705	16,104,233	13,301,000	110,000	149,000	2,544,233	16,104,233
May	14,037,202	108,000	988,311	15,133,513	13,128,000	123,000	177,000	1,705,513	15,133,513
	196,573,180	1,813,000	13,861,043	212,247,223	163,470,000	2,977,000	8,738,000	37,062,223	212,247,223

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

ELECTRIC PRODUCTION COSTS IN FUEL ADJUSTMENT CLAUSE

PASNY $, Purchased And Generated $

Test Year Ended May 31, 2003

	PASNY kWh $	PASNY Ancillary $	PASNY Total $	Purchased kWh $	Purchased Ancillary $	Oil $	Gas $	Purchased and Generated Total $
Column	J	K	L	M	N	O	P	Q
Source	Input	Input	=Sum(J:K)	Input	Input	Input	Input	=Sum(M:P)
June	$370,048	$43,544	$413,592	$176,269	$18,224	$32,041	$59,714	$286,248
July	377,800	58,120	435,920	361,079	38,532	43,030	171,580	614,220
August	420,480	48,779	469,258	282,104	21,670	34,487	163,179	501,440
September	384,605	35,860	420,465	235,835	15,338	13,552	26,214	290,940
October	551,949	49,784	601,733	74,686	5,412	4,786	7,973	92,856
November	457,956	40,426	498,382	35,606	2,092	2,987	0	40,685
December	479,186	28,875	508,061	113,378	4,468	13,666	0	131,512
January	467,532	35,963	503,496	188,222	8,148	20,574	0	216,945
February	537,686	44,603	582,289	125,448	5,745	5,110	0	136,302
March	586,866	55,887	642,753	71,529	1,914	19,254	1,135	93,832
April	500,966	61,654	562,620	56,057	4,468	9,786	13,195	83,507
May	447,915	62,548	510,463	58,329	7,185	8,661	13,543	87,719
	$5,582,988	$566,043	$6,149,031	$1,778,543	$133,196	$207,934	$456,533	$2,576,206

Rate Year Ended May 31, 2005

Column	j	k	l	m	n	o	p	q
Source	Same as Test Year	Same as Test Year	=Sum(j:k)	=h * AE	=h * AF	Same as Test Year	Same as Test Year	=Sum(m:p)
June	$370,048	$43,544	$413,592	$112,871	$11,669	$32,041	$59,714	$216,295
July	377,800	58,120	435,920	179,747	19,181	43,030	171,580	413,538
August	420,480	48,779	469,258	229,268	17,611	34,487	163,179	444,546
September	384,605	35,860	420,465	362,374	23,568	13,552	26,214	425,709
October	551,949	49,784	601,733	181,580	13,157	4,786	7,973	207,495
November	457,956	40,426	498,382	45,898	2,697	2,987	0	51,582
December	479,186	28,875	508,061	51,372	2,025	13,666	0	67,062
January	467,532	35,963	503,496	142,882	6,185	20,574	0	169,641
February	537,686	44,603	582,289	256,048	11,726	5,110	0	272,883
March	586,866	55,887	642,753	96,251	2,576	19,254	1,135	119,216
April	500,966	61,654	562,620	147,949	11,793	9,786	13,195	182,723
May	447,915	62,548	510,463	65,969	8,126	8,661	13,543	96,300
	5,582,988	566,043	$6,149,031	$1,872,209	$130,315	$207,934	$456,533	$2,666,991

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

ELECTRIC PRODUCTION COSTS IN FUEL ADJUSTMENT CLAUSE

Capacity $, TCC Credit $

Test Year Ended May 31, 2003

	Capacity $	Total TCC (Credit)	TCC Applied to PASNY	TCC Applied to Purchases	Available TCC (Credit)
Column	R	S	T	U	V
Source	Input	Input	Input	Input	=Sum(S:U)
June	$73,746	($332,996)	$204,678	$74,846	($53,472)
July	72,114	(439,750)	260,146	146,633	(32,971)
August	77,147	(464,873)	316,639	110,605	(37,629)
September	77,147	(187,711)	117,624	43,758	(26,329)
October	77,147	(81,217)	59,677	4,824	(16,715)
November	74,200	(81,210)	66,264	1,802	(13,144)
December	75,260	(165,327)	125,298	13,870	(26,159)
January	76,850	(375,168)	271,102	47,292	(56,774)
February	75,260	(124,943)	99,577	7,508	(17,858)
March	75,260	(311,623)	234,520	6,070	(71,033)
April	78,440	(178,031)	124,221	6,844	(46,966)
May	59,520	(360,210)	236,928	22,006	(101,276)
	$892,091	($3,103,058)	$2,116,674	$486,059	($500,325)

Rate Year Ended May 31, 2005

Column	r	s	t	u	v
Source	Same as Test Year	Same as Test Year	Same as Test Year	=h * AI	=Sum(s:u)
June	$73,746	($332,996)	$204,678	$47,926	($80,392)
July	72,114	(439,750)	260,146	72,995	(106,610)
August	77,147	(464,873)	316,639	89,890	(58,345)
September	77,147	(187,711)	117,624	67,237	(2,850)
October	77,147	(81,217)	59,677	11,729	(9,811)
November	74,200	(81,210)	66,264	2,323	(12,623)
December	75,260	(165,327)	125,298	6,284	(33,744)
January	76,850	(375,168)	271,102	35,900	(68,166)
February	75,260	(124,943)	99,577	15,325	(10,042)
March	75,260	(311,623)	234,520	8,167	(68,935)
April	78,440	(178,031)	124,221	18,064	(35,746)
May	59,520	(360,210)	236,928	24,889	(98,393)
	$892,091	($3,103,058)	$2,116,674	$400,728	($585,656)

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

ELECTRIC PRODUCTION COSTS IN FUEL ADJUSTMENT CLAUSE

Summary of Costs

Test Year Ended May 31, 2003

	PASNY Total $	Purchased and Generated Total $	Capacity $	Available TCC (Credit)	Total Energy $	Average $ / kWh Sales- Total Energy
Column	W	X	Y	Z	AA	AB
Source	=L	=U	=R	=V	=Sum(W:Z)	=AA / A
June	$413,592	$286,248	$73,746	($53,472)	$720,114	$0.05156
July	435,920	614,220	72,114	(32,971)	1,089,283	0.05803
August	469,258	501,440	77,147	(37,629)	1,010,216	0.04653
September	420,465	290,940	77,147	(26,329)	762,222	0.03637
October	601,733	92,856	77,147	(16,715)	755,020	0.04541
November	498,382	40,685	74,200	(13,144)	600,124	0.04443
December	508,061	131,512	75,260	(26,159)	688,674	0.04747
January	503,496	216,945	76,850	(56,774)	740,516	0.04286
February	582,289	136,302	75,260	(17,858)	775,994	0.04825
March	642,753	93,832	75,260	(71,033)	740,812	0.05077
April	562,620	83,507	78,440	(46,966)	677,601	0.04530
May	510,463	87,719	59,520	(101,276)	556,426	0.04123
	$6,149,031	$2,576,206	$892,091	($500,325)	$9,117,003	0.04641
Oil and Gas Costs (columns O and P)					(664,467)	
Credit for May 2003 Not in Trial Balance					72,000	
Rounding					(19,781)	
Other Purchased Electricity Costs					$8,504,755	

Rate Year Ended May 31, 2005

Column	w	x	y	z	aa	ab
Source	=l	=u	=r	=v	=Sum(w:z)	=aa / a
June	$413,592	$216,295	$73,746	($80,392)	$623,241	$0.03926
July	435,920	413,538	72,114	(106,610)	814,962	0.04452
August	469,258	444,546	77,147	(58,345)	932,607	0.04557
September	420,465	425,709	77,147	(2,850)	920,470	0.04667
October	601,733	207,495	77,147	(9,811)	876,564	0.05095
November	498,382	51,582	74,200	(12,623)	611,542	0.04232
December	508,061	67,062	75,260	(33,744)	616,639	0.04120
January	503,496	169,641	76,850	(68,166)	681,821	0.04295
February	582,289	272,883	75,260	(10,042)	920,391	0.05784
March	642,753	119,216	75,260	(68,935)	768,294	0.05181
April	562,620	182,723	78,440	(35,746)	788,037	0.05279
May	510,463	96,300	59,520	(98,393)	567,890	0.04046
	$6,149,031	$2,666,991	$892,091	($585,656)	$9,122,457	0.04641
Oil and Gas Costs (columns O and P)					(664,467)	
Other Purchased Electricity Costs					$8,457,990	

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

ELECTRIC PRODUCTION COSTS IN FUEL ADJUSTMENT CLAUSE

Costs per kWh Purchased or Generated

Test Year Ended May 31, 2003

	PASNY Energy	PASNY Ancillary	Purchased Energy	Purchased Ancillary	Generation Oil	Generation Gas	Purchased TCC Applied
Column	AC	AD	AE	AF	AG	AH	AI
Source	=J / E	=K / E	=M / H	=N / H	=O / F	=P / G	=U / H
June	$0.03044	$0.00358	$0.03464	$0.00358	$0.06080	$0.05043	$0.01471
July	0.03173	0.00488	0.04574	0.00488	0.06702	0.05119	0.01858
August	0.03109	0.00361	0.04695	0.00361	0.07245	0.05040	0.01841
September	0.03104	0.00289	0.04450	0.00289	0.06776	0.05328	0.00826
October	0.03800	0.00343	0.04730	0.00343	0.19942	0.05736	0.00306
November	0.03135	0.00277	0.04710	0.00277			0.00238
December	0.03213	0.00194	0.04912	0.00194	0.05766		0.00601
January	0.03247	0.00250	0.05770	0.00250	0.06768		0.01450
February	0.03960	0.00329	0.07173	0.00328	0.10872		0.00429
March	0.03904	0.00372	0.13889	0.00372	0.06709	0.16212	0.01179
April	0.03766	0.00464	0.05815	0.00464	0.08897	0.08855	0.00710
May	0.03412	0.00476	0.03868	0.00476	0.07042	0.07652	0.01459
	0.03415	0.00346	0.04816	0.00361	0.06985	0.05225	0.01316

Rate Year Ended May 31, 2005

Column	ac	ad	ae	af	ag	ah	ai
Source	=j / e	=k / e	=m / h	=n / h	=o / f	=p / g	=u / h
June	$0.03044	$0.00358	$0.03464	$0.00358	$0.06080	$0.05043	$0.01471
July	0.03173	0.00488	0.04574	0.00488	0.06702	0.05119	0.01858
August	0.03109	0.00361	0.04695	0.00361	0.07245	0.05040	0.01841
September	0.03104	0.00289	0.04450	0.00289	0.06776	0.05328	0.00826
October	0.03800	0.00343	0.04730	0.00343	0.19942	0.05736	0.00306
November	0.03135	0.00277	0.04710	0.00277			0.00238
December	0.03213	0.00194	0.04912	0.00194	0.05766		0.00601
January	0.03247	0.00250	0.05770	0.00250	0.06768		0.01450
February	0.03960	0.00329	0.07173	0.00328	0.10872		0.00429
March	0.03904	0.00372	0.13889	0.00372	0.06709	0.16212	0.01179
April	0.03766	0.00464	0.05815	0.00464	0.08897	0.08855	0.00710
May	0.03412	0.00476	0.03868	0.00476	0.07042	0.07652	0.01459
	0.03415	0.00346	0.05052	0.00352	0.06985	0.05225	0.01081

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

FUEL ADJUSTMENT CLAUSE (FAC) MONTHLY AMOUNTS

	KWh Sales	Fuel and Purchased Power Cost Recovered in Base Rates	Total Energy Cost	Unrecovered (Overrecovered) Fuel and Purchased Power Cost	FAC Amount
Rate Year Ended May 31, 2005- Present Rates					
June	15,873,567	$317,471	$623,241	$305,770	$0.01926
July	18,305,620	366,112	814,962	448,850	0.02452
August	20,467,130	409,343	932,607	523,264	0.02557
September	19,724,520	394,490	920,470	525,980	0.02667
October	17,203,953	344,079	876,564	532,485	0.03095
November	14,451,766	289,035	611,542	322,507	0.02232
December	14,966,948	299,339	616,639	317,300	0.02120
January	15,874,381	317,488	681,821	364,333	0.02295
February	15,911,839	318,237	920,391	602,154	0.03784
March	14,829,724	296,594	768,294	471,700	0.03181
April	14,926,528	298,531	788,037	489,506	0.03279
May	14,037,202	280,744	567,890	287,146	0.02046
	196,573,180	$3,931,463	$9,122,457	$5,190,994	0.026407
Rate Year Ended May 31, 2005- Proposed Rates					
June	15,873,567	$736,692	$623,241	($113,451)	($0.00715)
July	18,305,620	849,564	814,962	(34,602)	(0.00189)
August	20,467,130	949,880	932,607	(17,273)	(0.00084)
September	19,724,520	915,415	920,470	5,055	0.00026
October	17,203,953	798,435	876,564	78,129	0.00454
November	14,451,766	670,706	611,542	(59,164)	(0.00409)
December	14,966,948	694,616	616,639	(77,977)	(0.00521)
January	15,874,381	736,730	681,821	(54,909)	(0.00346)
February	15,911,839	738,468	920,391	181,923	0.01143
March	14,829,724	688,248	768,294	80,046	0.00540
April	14,926,528	692,740	788,037	95,297	0.00638
May	14,037,202	651,467	567,890	(83,577)	(0.00595)
	196,573,180	$9,122,961	$9,122,457	($504)	0.00000

Exhibit No. ______
(HSG-4)

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

SUMMARY OF PRESENT AND PROPOSED TARIFF RATES

Test Year Ended May 31, 2003 AND Rate Year Ended May 31, 2005

	Present Tariff Rates (excluding FAC)		FAC	Present Effective Rates (including FAC)		Proposed Effective Rates		Increase	
	Winter	Summer		Winter	Summer	Winter	Summer	Winter	Summer
SC 1- General Services - Small									
Billing Period	Monthly	Monthly				Monthly	Monthly		
Customer Charge per bill	$2.45	$2.45		$2.45	$2.45	$2.80	$2.80	14.29%	14.29%
Energy charge per kWh, all kWh	$0.0721	$0.0774	$0.0264	$0.0985	$0.1038	$0.1127	$0.1187	14.39%	14.39%
SC 3- Residential									
Billing Period	Bi-Monthly	Bi-Monthly				Bi-Monthly	Bi-Monthly		
Customer Charge per Bill	$4.92	$4.92		$4.92	$4.92	$5.63	$5.63	14.43%	14.43%
<u>Energy Charge, per kWh</u>									
First 500 kWh per bill	$0.0611	$0.0611	$0.0264	$0.0875	$0.0875	$0.1001	$0.1001	14.38%	14.38%
Excess of 500 kWh per bill	$0.0594	$0.0647	$0.0264	$0.0858	$0.0911	$0.0982	$0.1042	14.38%	14.38%
Special Provision A (Space Heating)-									
Excess of 1,200 kWh per bill	$0.0541	$0.0647	$0.0264	$0.0805	$0.0911	$0.0921	$0.1042	14.39%	14.38%
SC 5- General Services - Large									
Billing Period	Monthly	Monthly				Monthly	Monthly		
<u>Energy Charge, per kWh</u>									
First 30,000 kWh per bill	$0.0519	$0.0519	$0.0264	$0.0783	$0.0783	$0.0896	$0.0896	14.38%	14.38%
Excess of 30,000 kWh per bill	$0.0440	$0.0440	$0.0264	$0.0704	$0.0704	$0.0805	$0.0805	14.38%	14.38%
<u>Demand Charge, per kW Month</u>									
Secondary Service	$3.65	$3.65		$3.65	$3.65	$4.18	$4.18	14.52%	14.52%
High Tension Service	$3.11	$3.11		$3.11	$3.11	$3.56	$3.56	14.47%	14.47%

Notes

(1) All rates exclude Gross Utility Tax.
(2) All rate classes are subject to Fuel Adjustment Clause (FAC).
(3) Summer is June 1 through September 30. Winter is balance of year. Bills that cover more than one period are pro-rated based on num
(4) Minimum demands and ratchets apply to SC 5 Demand charge.

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

Exhibit No. __ (HSG-4)
Schedule 2
Page 1 of 5

BILL COMPARISONS
Service Classification 3 - Residential
Rate Year Ended May 31, 2005

		Present Rates		Proposed Rates		Increase	
	Sales (kWh)	Bi-Monthly Bill	Cost per kWh	Bi-Monthly Bill	Cost per kWh	$ per Bi-Monthly Bill	%
Summer	Minimum	$4.97		$5.69		$0.72	14.49%
	1	5.06	$5.06000	5.79	$5.79000	0.73	14.43%
	10	5.85	0.58500	6.70	0.67000	0.85	14.53%
	100	13.81	0.13810	15.80	0.15800	1.99	14.41%
	250	27.07	0.10828	30.96	0.12384	3.89	14.37%
	500	49.17	0.09834	56.24	0.11248	7.07	14.38%
	1,000	95.18	0.09518	108.87	0.10887	13.69	14.38%
	1,500	141.19	0.09413	161.50	0.10767	20.31	14.38%
	2,000	187.21	0.09361	214.13	0.10707	26.92	14.38%
	2,500	233.22	0.09329	266.76	0.10670	33.54	14.38%
	5,000	463.29	0.09266	529.92	0.10598	66.63	14.38%
Winter	Minimum	$4.97		$5.69		$0.72	14.49%
	1	5.06	$5.06000	5.79	$5.79000	0.73	14.43%
	10	5.85	0.58500	6.70	0.67000	0.85	14.53%
	100	13.81	0.13810	15.80	0.15800	1.99	14.41%
	250	27.07	0.10828	30.96	0.12384	3.89	14.37%
	500	49.17	0.09834	56.24	0.11248	7.07	14.38%
	1,000	92.50	0.09250	105.81	0.10581	13.31	14.39%
	1,500	135.84	0.09056	155.38	0.10359	19.54	14.38%
	2,000	179.18	0.08959	204.95	0.10248	25.77	14.38%
	2,500	222.51	0.08900	254.52	0.10181	32.01	14.39%
	5,000	439.20	0.08784	502.37	0.10047	63.17	14.38%

NOTE: Amounts above are for sales within the Village and include Gross Utility Tax at 1.0%

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

BILL COMPARISONS
Service Classification 3 - Residential / Space Heating
Rate Year Ended May 31, 2005

		Present Rates		Proposed Rates		Increase	
	Sales (kWh)	Bi-Monthly Bill	Cost per kWh	Bi-Monthly Bill	Cost per kWh	$ per Bi-Monthly Bill	%
Summer	Minimum	$4.97		$5.69		$0.72	14.49%
	1	5.06	$5.06000	5.79	$5.79000	0.73	14.43%
	100	13.81	0.13810	15.80	0.15800	1.99	14.41%
	500	49.17	0.09834	56.24	0.11248	7.07	14.38%
	1,000	95.18	0.09518	108.87	0.10887	13.69	14.38%
	1,500	141.19	0.09413	161.50	0.10767	20.31	14.38%
	2,000	187.21	0.09361	214.13	0.10707	26.92	14.38%
	3,000	279.23	0.09308	319.39	0.10646	40.16	14.38%
	5,000	463.29	0.09266	529.92	0.10598	66.63	14.38%
	7,000	647.34	0.09248	740.44	0.10578	93.10	14.38%
	10,000	923.42	0.09234	1,056.23	0.10562	132.81	14.38%
Winter	Minimum	$4.97		$5.69		$0.72	14.49%
	1	5.06	$5.06000	5.79	$5.79000	0.73	14.43%
	100	13.81	0.13810	15.80	0.15800	1.99	14.41%
	500	49.17	0.09834	56.24	0.11248	7.07	14.38%
	1,000	92.50	0.09250	105.81	0.10581	13.31	14.39%
	1,500	134.23	0.08949	153.54	0.10236	19.31	14.39%
	2,000	174.89	0.08745	200.05	0.10003	25.16	14.39%
	3,000	256.21	0.08540	293.07	0.09769	36.86	14.39%
	5,000	418.85	0.08377	479.11	0.09582	60.26	14.39%
	7,000	581.49	0.08307	665.15	0.09502	83.66	14.39%
	10,000	825.45	0.08255	944.21	0.09442	118.76	14.39%

NOTE: Amounts above are for sales within the Village and include Gross Utility Tax at 1.0%

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

BILL COMPARISONS
Service Classification 1 - General Service - Small
Rate Year Ended May 31, 2005

		Present Rates		Proposed Rates		Increase	
	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Monthly Bill	%
Summer	Minimum	$2.47		$2.83		$0.36	14.57%
	1	2.58	$2.58000	2.95	$2.95000	0.37	14.34%
	10	3.52	0.35200	4.03	0.40300	0.51	14.49%
	100	12.96	0.12960	14.82	0.14820	1.86	14.35%
	250	28.69	0.11476	32.81	0.13124	4.12	14.36%
	500	54.90	0.10980	62.80	0.12560	7.90	14.39%
	750	81.12	0.10816	92.78	0.12371	11.66	14.37%
	1,000	107.33	0.10733	122.77	0.12277	15.44	14.39%
	1,500	159.76	0.10651	182.74	0.12183	22.98	14.38%
	2,000	212.19	0.10610	242.71	0.12136	30.52	14.38%
	5,000	526.75	0.10535	602.52	0.12050	75.77	14.38%
Winter	Minimum	$2.47		$2.83		$0.36	14.57%
	1	2.57	$2.57000	2.94	$2.94000	0.37	14.40%
	10	3.47	0.34700	3.97	0.39700	0.50	14.41%
	100	12.42	0.12420	14.21	0.14210	1.79	14.41%
	250	27.35	0.10940	31.28	0.12512	3.93	14.37%
	500	52.23	0.10446	59.74	0.11948	7.51	14.38%
	750	77.10	0.10280	88.19	0.11759	11.09	14.38%
	1,000	101.98	0.10198	116.65	0.11665	14.67	14.39%
	1,500	151.73	0.10115	173.56	0.11571	21.83	14.39%
	2,000	201.48	0.10074	230.46	0.11523	28.98	14.38%
	5,000	499.98	0.10000	571.92	0.11438	71.94	14.39%

NOTE: Amounts above are for sales within the Village and include Gross Utility Tax at 1.0%

INCORPORATED VIL[illegible] OF ROCKVILLE CENTRE

Exhibit No. __ (HSG-4)
Schedule 2

BILL COMPARISONS
Service Classification 5 - General Service - Large
Rate Year Ended May 31, 2005

		Present Rates		Proposed Rates		Increase	
	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Monthly Bill	%
Secondary Service							
Up to 5 kW Demand	Minimum	$18.43		$21.11		$2.68	14.54%
	10	19.23	1.92300	22.02	2.20200	2.79	14.51%
	100	26.34	0.26340	30.16	0.30160	3.82	14.50%
	500	57.98	0.11596	66.35	0.13270	8.37	14.44%
	1,000	97.53	0.09753	111.59	0.11159	14.06	14.42%
	2,000	176.63	0.08832	202.06	0.10103	25.43	14.40%
	5,000	413.92	0.08278	473.48	0.09470	59.56	14.39%
10 kW Demand	Minimum	$36.87		$42.22		$5.35	14.51%
	10	37.66	3.76600	43.13	4.31300	5.47	14.52%
	100	44.78	0.44780	51.27	0.51270	6.49	14.49%
	500	76.42	0.15284	87.46	0.17492	11.04	14.45%
	1,000	115.97	0.11597	132.70	0.13270	16.73	14.43%
	2,000	195.06	0.09753	223.17	0.11159	28.11	14.41%
	5,000	432.36	0.08647	494.60	0.09892	62.24	14.40%
	10,000	827.85	0.08279	946.97	0.09470	119.12	14.39%
50 kW Demand	Minimum	$184.34		$211.11		$26.77	14.52%
	10	185.13	$18.51300	212.02	$21.20200	26.89	14.52%
	100	192.25	1.92250	220.16	2.20160	27.91	14.52%
	1,000	263.44	0.26344	301.59	0.30159	38.15	14.48%
	5,000	579.83	0.11597	663.48	0.13270	83.65	14.43%
	10,000	975.32	0.09753	1,115.86	0.11159	140.54	14.41%
	20,000	1,766.30	0.08832	2,020.60	0.10103	254.30	14.40%
	50,000	3,979.64	0.07959	4,552.22	0.09104	572.58	14.39%
100 kW Demand	Minimum	$368.69		$422.22		$53.53	14.52%
	10	369.48	$36.94800	423.13	$42.31300	53.65	14.52%
	100	376.60	3.76600	431.27	4.31270	54.67	14.52%
	1,000	447.78	0.44778	512.70	0.51270	64.92	14.50%
	5,000	764.18	0.15284	874.60	0.17492	110.42	14.45%
	10,000	1,159.67	0.11597	1,326.97	0.13270	167.30	14.43%
	20,000	1,950.64	0.09753	2,231.71	0.11159	281.07	14.41%
	50,000	4,163.99	0.08328	4,763.33	0.09527	599.34	14.39%
	100,000	7,719.89	0.07720	8,830.50	0.08831	1,110.61	14.39%

NOTE: Amounts above are for sales within the Village and include Gross Utility Tax at 1.0%

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

Exhibit No. __ (HSG-4)
Schedule 2

BILL COMPARISONS
Service Classification 5 - General Service - Large
Rate Year Ended May 31, 2005

		Present Rates		Proposed Rates		Increase	
	Sales (kWh)	Monthly Bill	Cost per kWh	Monthly Bill	Cost per kWh	$ per Monthly Bill	%
High Tension Service							
Up to 5 kW Demand	Minimum	$15.71		$17.98		$2.27	14.45%
	10	16.50	1.65000	18.88	1.88800	2.38	14.42%
	100	23.62	0.23620	27.03	0.27030	3.41	14.44%
	500	55.26	0.11052	63.22	0.12644	7.96	14.40%
	1,000	94.80	0.09480	108.45	0.10845	13.65	14.40%
	2,000	173.90	0.08695	198.93	0.09947	25.03	14.39%
	5,000	411.20	0.08224	470.35	0.09407	59.15	14.38%
10 kW Demand	Minimum	$31.41		$35.96		$4.55	14.49%
	10	32.21	3.22100	36.86	3.68600	4.65	14.44%
	100	39.32	0.39320	45.01	0.45010	5.69	14.47%
	500	70.96	0.14192	81.20	0.16240	10.24	14.43%
	1,000	110.51	0.11051	126.43	0.12643	15.92	14.41%
	2,000	189.61	0.09481	216.91	0.10846	27.30	14.40%
	5,000	426.90	0.08538	488.33	0.09767	61.43	14.39%
	10,000	822.39	0.08224	940.71	0.09407	118.32	14.39%
50 kW Demand	Minimum	$157.07		$179.80		$22.73	14.47%
	10	157.86	$15.78600	180.70	$18.07000	22.84	14.47%
	100	164.98	1.64980	188.85	1.88850	23.87	14.47%
	1,000	236.17	0.23617	270.27	0.27027	34.10	14.44%
	5,000	552.56	0.11051	632.17	0.12643	79.61	14.41%
	10,000	948.05	0.09481	1,084.54	0.10845	136.49	14.40%
	20,000	1,739.03	0.08695	1,989.29	0.09946	250.26	14.39%
	50,000	3,952.37	0.07905	4,520.90	0.09042	568.53	14.38%
100 kW Demand	Minimum	$314.14		$359.60		$45.46	14.47%
	10	314.93	$31.49300	360.50	$36.05000	45.57	14.47%
	100	322.05	3.22050	368.64	3.68640	46.59	14.47%
	1,000	393.24	0.39324	450.07	0.45007	56.83	14.45%
	5,000	709.63	0.14193	811.97	0.16239	102.34	14.42%
	10,000	1,105.12	0.11051	1,264.34	0.12643	159.22	14.41%
	20,000	1,896.10	0.09481	2,169.09	0.10845	272.99	14.40%
	50,000	4,109.44	0.08219	4,700.70	0.09401	591.26	14.39%
	100,000	7,665.35	0.07665	8,767.87	0.08768	1,102.52	14.38%

NOTE: Amounts above are for sales within the Village and include Gross Utility Tax at 1.0%

Exhibit No. ______
(HSG-5)

Exhibit No. __ (HSG-5)
Schedule 1

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

SUMMARY OF ELECTRIC SALES, CUSTOMERS AND REVENUE
ALL SERVICE CLASSIFICATIONS
Rate Year Ended May 31, 2005

			Revenue		Revenue per Customer		Revenue per kWh		
	Sales (kWh)	Average Cus-tomers	Present Rates	Proposed Rates	Present Rates	Proposed Rates	Present Rates	Proposed Rates	Increase
SC 1- General Services - Small	2,847,347	334	$ 297,772	$ 341,571	$ 892	$ 1,023	$ 0.10458	$ 0.11996	14.71%
SC 3- Residential	89,527,108	8,801	8,202,587	9,406,752	932	1,069	0.09162	0.10507	14.68%
SC 3- Residential / Space Heating	2,156,075	131	191,604	219,750	1,463	1,677	0.08887	0.10192	14.69%
Total SC 3- Residential	91,683,183	8,932	8,394,191	9,626,502	940	1,076	0.09156	0.10500	14.68%
SC 5- General Services - Large	96,294,653	764	8,341,990	9,572,506	10,915	12,525	0.08663	0.09941	14.75%
Street Lighting	3,136,193	1	259,200	297,234	259,200	297,234	0.08265	0.09478	14.67%
Operating Municipality	2,130,523	37	195,412	224,173	5,281	6,059	0.09172	0.10522	14.72%
Public Authorities	481,281	10	48,897	56,074	4,890	5,607	0.10160	0.11651	14.68%
Rounding			93,444	93,444					
TOTAL	196,573,180	10,078	$ 17,630,906	$ 20,211,504	$ 1,749	$ 2,005	$ 0.08969	$ 0.10282	14.64%

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

SUMMARY OF ELECTRIC SALES, CUSTOMERS AND REVENUE
Service Classification 3 - Residential
Rate Year Ended May 31, 2005

			Revenue - Present Rates			Revenue - Proposed Rates		
	Sales (kWh)	Bills Rendered	Base Rates	Fuel Clause	Total	Base Rates	Fuel Clause	Total
June 2002	6,501,804	4,410	$ 421,523	$ 125,225	$ 546,748	$ 680,530	$ (46,488)	$ 634,042
July 2002	7,842,738	4,435	527,049	192,304	719,353	842,148	(14,823)	827,325
August 2002	9,949,933	4,416	664,566	254,420	918,986	1,063,735	(8,358)	1,055,377
September 2002	9,238,910	4,437	618,293	246,402	864,695	989,115	2,402	991,517
October 2002	8,397,178	4,413	554,653	259,893	814,546	890,638	38,123	928,761
November 2002	6,336,895	4,440	405,847	141,439	547,286	657,568	(25,918)	631,650
December 2002	6,794,825	4,397	433,132	144,050	577,182	702,749	(35,401)	667,348
January 2003	7,312,560	4,419	464,264	167,823	632,087	754,155	(25,301)	728,854
February 2003	7,851,064	4,388	496,455	297,084	793,539	807,405	89,738	897,143
March 2003	6,595,449	4,434	421,326	209,801	631,127	683,161	35,615	718,776
April 2003	6,887,665	4,314	438,220	225,847	664,067	711,400	43,943	755,343
May 2003	5,818,087	4,305	373,933	119,038	492,971	605,234	(34,618)	570,616
TOTAL	89,527,108	52,808	$ 5,819,261	$ 2,383,326	$ 8,202,587	$ 9,387,838	$ 18,914	$ 9,406,752
Average Customers		8,801						

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

SUMMARY OF ELECTRIC SALES, CUSTOMERS AND REVENUE
Service Classification 3 - Residential / Space Heating
Rate Year Ended May 31, 2005

			Revenue - Present Rates			Revenue - Proposed Rates		
	Sales (kWh)	Bills Rendered	Base Rates	Fuel Clause	Total	Base Rates	Fuel Clause	Total
June 2002	156,583	101	$ 10,225	$ 3,016	$ 13,241	$ 16,473	$ (1,120)	$ 15,353
July 2002	188,876	29	12,434	4,631	17,065	19,986	(357)	19,629
August 2002	239,624	100	15,975	6,127	22,102	25,584	(201)	25,383
September 2002	222,500	30	14,635	5,934	20,569	23,529	58	23,587
October 2002	202,229	101	13,219	6,259	19,478	21,291	918	22,209
November 2002	152,611	30	8,690	3,406	12,096	14,596	(624)	13,972
December 2002	163,639	100	10,147	3,469	13,616	16,599	(853)	15,746
January 2003	176,108	30	9,989	4,042	14,031	16,799	(609)	16,190
February 2003	189,077	101	11,545	7,155	18,700	18,975	2,161	21,136
March 2003	158,838	31	9,052	5,053	14,105	15,200	858	16,058
April 2003	165,875	101	10,259	5,439	15,698	16,796	1,058	17,854
May 2003	140,117	32	8,036	2,867	10,903	13,467	(834)	12,633
TOTAL	2,156,075	786	$ 134,206	$ 57,398	$ 191,604	$ 219,295	$ 455	$ 219,750
Average Customers		131						

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

SUMMARY OF ELECTRIC SALES, CUSTOMERS AND REVENUE
Service Classification 1 - General Service - Small
Rate Year Ended May 31, 2005

			Revenue - Present Rates			Revenue - Proposed Rates		
	Sales (kWh)	Bills Rendered	Base Rates	Fuel Clause	Total	Base Rates	Fuel Clause	Total
June 2002	252,192	324	$ 20,516	$ 4,857	$ 25,373	$ 31,165	$ (1,803)	$ 29,362
July 2002	281,426	323	22,800	6,901	29,701	34,668	(532)	34,136
August 2002	281,275	323	22,788	7,192	29,980	34,650	(236)	34,414
September 2002	281,213	326	22,790	7,500	30,290	34,652	73	34,725
October 2002	233,500	327	17,814	7,227	25,041	27,502	1,060	28,562
November 2002	214,553	329	16,439	4,789	21,228	25,351	(878)	24,473
December 2002	214,015	334	16,412	4,537	20,949	25,304	(1,115)	24,189
January 2003	225,672	336	17,266	5,179	22,445	26,637	(781)	25,856
February 2003	212,142	341	16,292	8,027	24,319	25,111	2,425	27,536
March 2003	217,839	341	16,707	6,929	23,636	25,759	1,176	26,935
April 2003	213,505	344	16,400	7,001	23,401	25,275	1,362	26,637
May 2003	220,015	358	16,908	4,501	21,409	26,055	(1,309)	24,746
TOTAL	2,847,347	4,006	$ 223,132	$ 74,640	$ 297,772	$ 342,129	$ (558)	$ 341,571
Average Customers		334						

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

SUMMARY OF ELECTRIC SALES, CUSTOMERS AND REVENUE
Service Classification 5 - General Service - Large
Rate Year Ended May 31, 2005

			Revenue - Present Rates			Revenue - Proposed Rates		
	Sales (kWh)	Bills Rendered	Base Rates	Fuel Clause	Total	Base Rates	Fuel Clause	Total
June 2002	8,528,914	750	$ 498,519	$ 164,267	$ 662,786	$ 830,301	$ (60,982)	$ 769,319
July 2002	9,517,571	736	574,202	233,371	807,573	947,076	(17,988)	929,088
August 2002	9,512,467	743	547,621	243,234	790,855	916,438	(7,990)	908,448
September 2002	9,510,349	749	543,506	253,641	797,147	911,652	2,473	914,125
October 2002	7,896,739	755	473,492	244,404	717,896	782,430	35,851	818,281
November 2002	7,255,995	758	452,297	161,954	614,251	738,692	(29,677)	709,015
December 2002	7,237,795	760	439,149	153,441	592,590	723,061	(37,709)	685,352
January 2003	7,632,025	771	466,966	175,155	642,121	766,914	(26,407)	740,507
February 2003	7,174,433	774	456,849	271,481	728,330	741,435	82,004	823,439
March 2003	7,367,119	775	449,208	234,348	683,556	738,516	39,782	778,298
April 2003	7,220,558	778	450,203	236,762	686,965	735,211	46,067	781,278
May 2003	7,440,688	822	465,684	152,236	617,920	759,628	(44,272)	715,356
TOTAL	96,294,653	9,171	$ 5,817,696	$ 2,524,294	$ 8,341,990	$ 9,591,354	$ (18,848)	$ 9,572,506
Average Customers		764						

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

SUMMARY OF ELECTRIC SALES, CUSTOMERS AND REVENUE
Street Lighting (Service Classification 5 Applies)
Rate Year Ended May 31, 2005

			Revenue - Present Rates			Revenue - Proposed Rates		
	Sales (kWh)	Bills Rendered	Base Rates	Fuel Clause	Total	Base Rates	Fuel Clause	Total
June 2002	196,893	1	$ 11,824	$ 3,792	$ 15,616	$ 19,521	$ (1,408)	$ 18,113
July 2002	205,110	1	12,189	5,029	17,218	20,189	(388)	19,801
August 2002	234,349	1	13,487	5,992	19,479	22,564	(197)	22,367
September 2002	249,136	1	14,143	6,644	20,787	23,765	65	23,830
October 2002	277,155	1	15,387	8,578	23,965	26,041	1,258	27,299
November 2002	305,992	1	16,667	6,830	23,497	28,383	(1,252)	27,131
December 2002	331,587	1	17,803	7,030	24,833	30,462	(1,728)	28,734
January 2003	326,268	1	17,567	7,488	25,055	30,030	(1,129)	28,901
February 2003	278,202	1	15,433	10,527	25,960	26,126	3,180	29,306
March 2003	279,394	1	15,486	8,888	24,374	26,223	1,509	27,732
April 2003	237,579	1	13,630	7,790	21,420	22,826	1,516	24,342
May 2003	214,528	1	12,607	4,389	16,996	20,954	(1,276)	19,678
TOTAL	3,136,193	12	$ 176,223	$ 82,977	$ 259,200	$ 297,084	$ 150	$ 297,234
Average Customers		1						

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

SUMMARY OF ELECTRIC SALES, CUSTOMERS AND REVENUE
Operating Municipality (Service Classification 5 Applies)
Rate Year Ended May 31, 2005

			Revenue - Present Rates			Revenue - Proposed Rates		
	Sales (kWh)	Bills Rendered	Base Rates	Fuel Clause	Total	Base Rates	Fuel Clause	Total
June 2002	195,789	37	$ 12,445	$ 3,771	$ 16,216	$ 20,203	$ (1,400)	$ 18,803
July 2002	228,305	37	13,888	5,598	19,486	22,844	(431)	22,413
August 2002	209,365	37	13,048	5,353	18,401	21,305	(176)	21,129
September 2002	181,981	37	11,832	4,853	16,685	19,081	47	19,128
October 2002	157,288	37	10,736	4,868	15,604	17,075	714	17,789
November 2002	146,178	37	10,243	3,263	13,506	16,173	(598)	15,575
December 2002	185,183	37	11,974	3,926	15,900	19,341	(965)	18,376
January 2003	162,523	37	10,968	3,730	14,698	17,500	(562)	16,938
February 2003	167,417	37	11,185	6,335	17,520	17,898	1,914	19,812
March 2003	171,397	37	11,362	5,452	16,814	18,221	926	19,147
April 2003	161,545	37	10,925	5,297	16,222	17,421	1,031	18,452
May 2003	163,552	37	11,014	3,346	14,360	17,584	(973)	16,611
TOTAL	2,130,523	444	$ 139,620	$ 55,792	$ 195,412	$ 224,646	$ (473)	$ 224,173
Average Customers		37						

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

SUMMARY OF ELECTRIC SALES, CUSTOMERS AND REVENUE
Public Authorities (Service Classification 1 Applies)
Rate Year Ended May 31, 2005

			Revenue - Present Rates			Revenue - Proposed Rates		
	Sales (kWh)	Bills Rendered	Base Rates	Fuel Clause	Total	Base Rates	Fuel Clause	Total
June 2002	41,392	10	$ 3,261	$ 797	$ 4,058	$ 4,993	$ (296)	$ 4,697
July 2002	41,594	10	3,277	1,020	4,297	5,017	(79)	4,938
August 2002	40,117	10	3,161	1,026	4,187	4,840	(34)	4,806
September 2002	40,431	10	3,186	1,078	4,264	4,877	11	4,888
October 2002	39,865	10	2,928	1,234	4,162	4,565	181	4,746
November 2002	39,543	10	2,905	883	3,788	4,529	(162)	4,367
December 2002	39,903	10	2,931	846	3,777	4,570	(208)	4,362
January 2003	39,226	10	2,882	900	3,782	4,493	(136)	4,357
February 2003	39,504	10	2,902	1,495	4,397	4,524	452	4,976
March 2003	39,689	10	2,916	1,263	4,179	4,545	214	4,759
April 2003	39,800	10	2,924	1,305	4,229	4,558	254	4,812
May 2003	40,217	10	2,954	823	3,777	4,605	(239)	4,366
TOTAL	481,281	120	$ 36,227	$ 12,670	$ 48,897	$ 56,116	$ (42)	$ 56,074
Average Customers		10						

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

DETAIL OF BILLING UNITS AND RATES
Rate Year Ended May 31, 2005- Present Rates

Rate Schedule		Residential-Special SC-3A	Residential-Others SC-3	Commercial-Small SC-1	Commercial-Large SC-5	Street Lighting SC-5	Operating Municipality SC-5	Public Authorities SC-1	Total
		BILLING UNITS							
		kWh Sales Rate Year Ended May 31, 2005							
June	Summer	156,583	6,501,804	252,192	8,528,914	196,893	195,789	41,392	15,873,567
July	Summer	188,876	7,842,738	281,426	9,517,571	205,110	228,305	41,594	18,305,620
August	Summer	239,624	9,949,933	281,275	9,512,467	234,349	209,365	40,117	20,467,130
September	Summer	222,500	9,238,910	281,213	9,510,349	249,136	181,981	40,431	19,724,520
October	Winter	202,229	8,397,178	233,500	7,896,739	277,155	157,288	39,865	17,203,953
November	Winter	152,611	6,336,895	214,553	7,255,995	305,992	146,178	39,543	14,451,766
December	Winter	163,639	6,794,825	214,015	7,237,795	331,587	185,183	39,903	14,966,948
January	Winter	176,108	7,312,560	225,672	7,632,025	326,268	162,523	39,226	15,874,381
February	Winter	189,077	7,851,064	212,142	7,174,433	278,202	167,417	39,504	15,911,839
March	Winter	158,838	6,595,449	217,839	7,367,119	279,394	171,397	39,689	14,829,724
April	Winter	165,875	6,887,665	213,505	7,220,558	237,579	161,545	39,800	14,926,528
May	Winter	140,117	5,818,087	220,015	7,440,688	214,528	163,552	40,217	14,037,202
		2,156,075	89,527,108	2,847,347	96,294,653	3,136,193	2,130,523	481,281	196,573,180
									196,573,180
		Number of Bills Rate Year Ended May 31, 2005							
June		101	4,410	324	750	1	37	10	5,633
July		29	4,435	323	736	1	37	10	5,571
August		100	4,416	323	743	1	37	10	5,630
September		30	4,437	326	749	1	37	10	5,590
October		101	4,413	327	755	1	37	10	5,644
November		30	4,440	329	758	1	37	10	5,605
December		100	4,397	334	760	1	37	10	5,639
January		30	4,419	336	771	1	37	10	5,604
February		101	4,388	341	774	1	37	10	5,652
March		31	4,434	341	775	1	37	10	5,629
April		101	4,314	344	778	1	37	10	5,585
May		32	4,305	358	822	1	37	10	5,565
		786	52,808	4,006	9,171	12	444	120	67,347
Monthly Demand - kW						771	963		

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

DETAIL OF BILLING UNITS AND RATES
Rate Year Ended May 31, 2005- Present Rates

Rate Schedule		Residential- Special SC-3A	Residential- Others SC-3	Commercial- Small SC-1	Commercial- Large SC-5	Street Lighting SC-5	Operating Municipality SC-5	Public Authorities SC-1	Total
RATES AND CHARGES									
Tariff Rates									
Customer Charge		$4.92	$4.92	$2.45				$2.45	
Energy Charge 1- Sum	Summer	$0.0611	$0.0611	$0.0774	$0.0519	$0.0519	$0.0519	$0.0774	
Energy Charge 1- Wint	Winter	$0.0611	$0.0611	$0.0721	$0.0519	$0.0519	$0.0519	$0.0721	
Energy Charge 2- Sum	Summer	$0.0647	$0.0647		$0.0440	$0.0440	$0.0440		
Energy Charge 2- Wint	Winter	$0.0594	$0.0594		$0.0440	$0.0440	$0.0440		
Energy Charge 3- Sum	Summer	$0.0647							
Energy Charge 3- Wint	Winter	$0.0541							
Demand- Secondary					$3.65	$3.65	$3.65		
Demand- High Tension					$3.11	$3.11			
Effective Rates with Gross Utility Tax									
Gross Utility Tax Multiplier		1.01010	1.01010	1.01010	1.008750	1.01010	1.01010	1.01010	
Customer Charge		$4.97	$4.97	$2.47				$2.47	
Energy Charge 1- Sum	Summer	$0.06172	$0.06172	$0.07818	$0.05235	$0.05242	$0.05242	$0.07818	
Energy Charge 1- Wint	Winter	$0.06172	$0.06172	$0.07283	$0.05235	$0.05242	$0.05242	$0.07283	
Energy Charge 2- Sum	Summer	$0.06535	$0.06535		$0.04439	$0.04444	$0.04444		
Energy Charge 2- Wint	Winter	$0.06000	$0.06000		$0.04439	$0.04444	$0.04444		
Energy Charge 3- Sum	Summer	$0.06535							
Energy Charge 3- Wint	Winter	$0.05465							
Demand- Secondary					$3.68	$3.69	$3.69		
Demand- High Tension					$3.14	$3.14			

Monthly Effective kWh Rates

		Residential- SC 3 and SC 3A			Commercial- SC 1	Large Commercial- SC 5	
		Block 1 Rate	Block 2 Rate	Block 3 Rate		Block 1 Rate	Block 2 Rate
June	Summer	$0.0617	$0.0613	$0.0573	$0.0782	$0.0524	$0.0444
July	Summer	$0.0617	$0.0654	$0.0654	$0.0782	$0.0524	$0.0444
August	Summer	$0.0617	$0.0654	$0.0654	$0.0782	$0.0524	$0.0444
September	Summer	$0.0617	$0.0654	$0.0654	$0.0782	$0.0524	$0.0444
October	Winter	$0.0617	$0.0640	$0.0627	$0.0728	$0.0524	$0.0444
November	Winter	$0.0617	$0.0600	$0.0547	$0.0728	$0.0524	$0.0444
December	Winter	$0.0617	$0.0600	$0.0547	$0.0728	$0.0524	$0.0444
January	Winter	$0.0617	$0.0600	$0.0547	$0.0728	$0.0524	$0.0444
February	Winter	$0.0617	$0.0600	$0.0547	$0.0728	$0.0524	$0.0444
March	Winter	$0.0617	$0.0600	$0.0547	$0.0728	$0.0524	$0.0444
April	Winter	$0.0617	$0.0600	$0.0547	$0.0728	$0.0524	$0.0444
May	Winter	$0.0617	$0.0600	$0.0547	$0.0728	$0.0524	$0.0444

Exhibit No. __ (HSG-5)
Schedule 4

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

DETAIL OF BILLING UNITS AND RATES
Rate Year Ended May 31, 2005- Proposed Rates

Rate Schedule		Residential-Special SC-3A	Residential-Others SC-3	Commercial-Small SC-1	Commercial-Large SC-5	Street Lighting SC-5	Operating Municipality SC-5	Public Authorities SC-1	Total
		BILLING UNITS							
		kWh Sales Rate Year Ended May 31, 2005							
June	Summer	156,583	6,501,804	252,192	8,528,914	196,893	195,789	41,392	15,873,567
July	Summer	188,876	7,842,738	281,426	9,517,571	205,110	228,305	41,594	18,305,620
August	Summer	239,624	9,949,933	281,275	9,512,467	234,349	209,365	40,117	20,467,130
September	Summer	222,500	9,238,910	281,213	9,510,349	249,136	181,981	40,431	19,724,520
October	Winter	202,229	8,397,178	233,500	7,896,739	277,155	157,288	39,865	17,203,953
November	Winter	152,611	6,336,895	214,553	7,255,995	305,992	146,178	39,543	14,451,766
December	Winter	163,639	6,794,825	214,015	7,237,795	331,587	185,183	39,903	14,966,948
January	Winter	176,108	7,312,560	225,672	7,632,025	326,268	162,523	39,226	15,874,381
February	Winter	189,077	7,851,064	212,142	7,174,433	278,202	167,417	39,504	15,911,839
March	Winter	158,838	6,595,449	217,839	7,367,119	279,394	171,397	39,689	14,829,724
April	Winter	165,875	6,887,665	213,505	7,220,558	237,579	161,545	39,800	14,926,528
May	Winter	140,117	5,818,087	220,015	7,440,688	214,528	163,552	40,217	14,037,202
		2,156,075	89,527,108	2,847,347	96,294,653	3,136,193	2,130,523	481,281	196,573,180
									196,573,180
		Number of Bills Rate Year Ended May 31, 2005							
June		101	4,410	324	750	1	37	10	5,633
July		29	4,435	323	736	1	37	10	5,571
August		100	4,416	323	743	1	37	10	5,630
September		30	4,437	326	749	1	37	10	5,590
October		101	4,413	327	755	1	37	10	5,644
November		30	4,440	329	758	1	37	10	5,605
December		100	4,397	334	760	1	37	10	5,639
January		30	4,419	336	771	1	37	10	5,604
February		101	4,388	341	774	1	37	10	5,652
March		31	4,434	341	775	1	37	10	5,629
April		101	4,314	344	778	1	37	10	5,585
May		32	4,305	358	822	1	37	10	5,565
		786	52,808	4,006	9,171	12	444	120	67,347
Monthly Demand - kW						771	963		

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

DETAIL OF BILLING UNITS AND RATES
Rate Year Ended May 31, 2005- Proposed Rates

Rate Schedule		Residential-Special SC-3A	Residential-Others SC-3	Commercial-Small SC-1	Commercial-Large SC-5	Street Lighting SC-5	Operating Municipality SC-5	Public Authorities SC-1	Total
		RATES AND CHARGES							
		Tariff Rates							
Customer Charge		$5.63	$5.63	$2.80				$2.80	
Energy Charge 1- Sum	Summer	$0.10009	$0.10009	$0.11874	$0.08957	$0.08957	$0.08957	$0.11874	
Energy Charge 1- Wint	Winter	$0.10009	$0.10009	$0.11268	$0.08957	$0.08957	$0.08957	$0.11268	
Energy Charge 2- Sum	Summer	$0.10421	$0.10421		$0.08053	$0.08053	0		
Energy Charge 2- Wint	Winter	$0.09815	$0.09815		$0.08053	$0.08053	0		
Energy Charge 3- Sum	Summer	$0.10421							
Energy Charge 3- Wint	Winter	$0.09209							
Demand- Secondary					$4.18	$4.18	$4.18		
Demand- High Tension					$3.56	$3.56			
		Effective Rates with Gross Utility Tax							
Gross Utility Tax Multiplier		1.01010	1.01010	1.01010	1.008750	1.01010	1.01010	1.01010	
Customer Charge		$5.69	$5.69	$2.83				$2.83	
Energy Charge 1- Sum	Summer	$0.10110	$0.10110	$0.11994	$0.09035	$0.09047	$0.09047	$0.11994	
Energy Charge 1- Wint	Winter	$0.10110	$0.10110	$0.11382	$0.09035	$0.09047	$0.09047	$0.11382	
Energy Charge 2- Sum	Summer	$0.10526	$0.10526		$0.08123	$0.08134	$0.08134		
Energy Charge 2- Wint	Winter	$0.09914	$0.09914		$0.08123	$0.08134	$0.08134		
Energy Charge 3- Sum	Summer	$0.10526							
Energy Charge 3- Wint	Winter	$0.09302							
Demand- Secondary					$4.22	$4.22	$4.22		
Demand- High Tension					$3.59	$3.60			

Monthly Effective kWh Rates

		Residential- SC 3 and SC 3A			Commercial- SC 1	Large Commercial- SC 5	
		Block 1 Rate	Block 2 Rate	Block 3 Rate		Block 1 Rate	Block 2 Rate
June	Summer	$0.1011	$0.1007	$0.0961	$0.1199	$0.0904	$0.0812
July	Summer	$0.1011	$0.1053	$0.1053	$0.1199	$0.0904	$0.0812
August	Summer	$0.1011	$0.1053	$0.1053	$0.1199	$0.0904	$0.0812
September	Summer	$0.1011	$0.1053	$0.1053	$0.1199	$0.0904	$0.0812
October	Winter	$0.1011	$0.1037	$0.1022	$0.1138	$0.0904	$0.0812
November	Winter	$0.1011	$0.0991	$0.0930	$0.1138	$0.0904	$0.0812
December	Winter	$0.1011	$0.0991	$0.0930	$0.1138	$0.0904	$0.0812
January	Winter	$0.1011	$0.0991	$0.0930	$0.1138	$0.0904	$0.0812
February	Winter	$0.1011	$0.0991	$0.0930	$0.1138	$0.0904	$0.0812
March	Winter	$0.1011	$0.0991	$0.0930	$0.1138	$0.0904	$0.0812
April	Winter	$0.1011	$0.0991	$0.0930	$0.1138	$0.0904	$0.0812
May	Winter	$0.1011	$0.0991	$0.0930	$0.1138	$0.0904	$0.0812

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

FORECAST OF ELECTRIC SALES
Rate Year Ended May 31, 2005

	Residential-Special Provision A	Residential-Others	Commercial-Small	Commercial-Large	Street Lighting	Operating Municipality	Public Authorities	Total
	Test Year Ended May 31, 2003							
kWh Sales - Actual	2,168,621	90,048,045	2,824,120	95,509,145	3,219,416	2,187,063	494,052	196,450,462
Residential subtotals	2.35%	97.65%						
Commercial subtotals			2.87%	97.13%				
Street Lighting, Oper Muni and PA subtotals					54.56%	37.07%	8.37%	
	Rate Year Ended May 31, 2005 From Integrated Resource Plan							
	Residential- Total		Commercial- Total		StL / Muni / PA Total			Total
kWh Sales - IRP	92,997,000		99,142,000		5,748,000			197,887,000
Eliminate New Residential Apartments	(1,314,000)							(1,314,000)
kWh Sales - Based on IRP	91,683,000		99,142,000		5,748,000			196,573,000
kWh Sales - Detailed	2,156,071	89,526,929	2,847,347	96,294,653	3,136,193	2,130,527	481,281	196,573,001
	Historical Monthly % of Annual Totals by Service Classification							
June	7.26%	7.26%	8.86%	8.86%	6.28%	9.19%	8.60%	8.10%
July	8.76%	8.76%	9.88%	9.88%	6.54%	10.72%	8.64%	9.33%
August	11.11%	11.11%	9.88%	9.88%	7.47%	9.83%	8.34%	10.38%
September	10.32%	10.32%	9.88%	9.88%	7.94%	8.54%	8.40%	10.02%
October	9.38%	9.38%	8.20%	8.20%	8.84%	7.38%	8.28%	8.73%
November	7.08%	7.08%	7.54%	7.54%	9.76%	6.86%	8.22%	7.37%
December	7.59%	7.59%	7.52%	7.52%	10.57%	8.69%	8.29%	7.62%
January	8.17%	8.17%	7.93%	7.93%	10.40%	7.63%	8.15%	8.08%
February	8.77%	8.77%	7.45%	7.45%	8.87%	7.86%	8.21%	8.07%
March	7.37%	7.37%	7.65%	7.65%	8.91%	8.04%	8.25%	7.55%
April	7.69%	7.69%	7.50%	7.50%	7.58%	7.58%	8.27%	7.59%
May	6.50%	6.50%	7.73%	7.73%	6.84%	7.68%	8.36%	7.16%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Rate Year Ended May 31, 2005 Detailed by Service Classification by Month							
June	156,583	6,501,804	252,192	8,528,914	196,893	195,789	41,392	15,873,567
July	188,876	7,842,738	281,426	9,517,571	205,110	228,305	41,594	18,305,620
August	239,624	9,949,933	281,275	9,512,467	234,349	209,365	40,117	20,467,130
September	222,500	9,238,910	281,213	9,510,349	249,136	181,981	40,431	19,724,520
October	202,229	8,397,178	233,500	7,896,739	277,155	157,288	39,865	17,203,953
November	152,611	6,336,895	214,553	7,255,995	305,992	146,178	39,543	14,451,766
December	163,639	6,794,825	214,015	7,237,795	331,587	185,183	39,903	14,966,948
January	176,108	7,312,560	225,672	7,632,025	326,268	162,523	39,226	15,874,381
February	189,077	7,851,064	212,142	7,174,433	278,202	167,417	39,504	15,911,839
March	158,838	6,595,449	217,839	7,367,119	279,394	171,397	39,689	14,829,724
April	165,875	6,887,665	213,505	7,220,558	237,579	161,545	39,800	14,926,528
May	140,117	5,818,087	220,015	7,440,688	214,528	163,552	40,217	14,037,202
	2,156,075	89,527,108	2,847,347	96,294,653	3,136,193	2,130,523	481,281	196,573,180

Exhibit No. ______
(HSG-6)

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

Exhibit No. __ (HSG-6)
Schedule 1

RATE OF RETURN ON RATE BASE
Rate Year Ended May 31, 2005

	ACTUAL Test Year Ended May 31, 2003	PRESENT RATES Rate Year Ended May 31, 2005	PROPOSED RATES Rate Year Ended May 31, 2005
OPERATING REVENUE			
Sales of Electricity	$ 17,571,183	$ 17,630,906	$ 20,211,504
Street Lighting Rental	159,996	159,996	159,996
Misc Other Revenue	4,545	9,745	9,745
Interest Income	73,857	53,857	53,857
Other Electric Income	2,004,197	4,197	4,197
	19,813,778	17,858,701	20,439,299
OPERATING EXPENSES			
Electric Production:			
Generation Costs	1,476,281	1,670,883	1,670,883
Fuel for Generation	664,467	664,467	664,467
Other Production Expense	440,179	467,338	467,338
Purchased Electricity	8,504,755	8,457,990	8,457,990
	11,085,682	11,260,678	11,260,678
Transmission	100,377	156,563	156,563
Distribution	559,166	593,117	593,117
Street Lighting	299,535	317,860	317,860
Customer Accounts	362,805	384,442	384,442
General & Administrative	1,865,284	2,577,815	2,577,815
Depreciation Expense	1,243,209	1,784,112	1,784,112
Special Contract Expense	2,000,000		
Tax Equivalency	1,624,411	1,821,777	1,821,777
Gross Utility Tax	165,653	164,305	188,478
Uncollectible Accounts	25,529	30,000	30,000
	19,331,651	19,090,669	19,114,842
NET ELECTRIC OPERATING INCOME (LOSS)	$ 482,127	$ (1,231,968)	$ 1,324,457
RATE BASE	$ 23,455,484	$ 26,451,267	$ 26,451,267
RATE OF RETURN ON RATE BASE	2.06%	(4.66%)	5.01%

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

COMPUTATION OF RATE OF RETURN
Rate Year Ended May 31, 2005

RATE OF RETURN	Amount	% of Total	Cost	Rate of Return
Long Term Debt	$6,882,675	26.0%	5.75%	1.50%
Customer Deposits	723,217	2.7%	1.50%	0.04%
Pro Forma New Debt Issuance	5,000,000	18.9%	4.50%	0.85%
Surplus / New Debt	13,845,375	52.3%	5.00%	2.62%
	$26,451,267	100.0%		5.01%

LONG TERM DEBT

Issue	Principal Balance May 31, 2002	Principal Balance May 31, 2003	Principal Balance May 31, 2004	Principal Balance May 31, 2005	Interest Expense Rate Year
1991 Bonds	$802,500	$642,000	$481,500	$321,000	$22,751
1992 Bonds	7,135,000	6,655,000	6,175,000	5,675,000	346,875
1994 Bonds	621,350	500,000	380,700	261,900	16,426
1998 Bonds	372,000	317,000	262,000	208,250	9,826
TOTAL	$8,930,850	$8,114,000	$7,299,200	$6,466,150	$395,878
Rate Year Average				$6,882,675	
Rate Year Average Rate				5.75%	

Exhibit No. __ (HSG-6)
Schedule 3

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

COMPUTATION OF RATE BASE
Rate Year Ended May 31, 2005

	Balance, May 31, 2005	Balance, May 31, 2004	Average
Utility Plant in Service			
Assets	$ 49,825,548	$ 49,059,448	$ 49,442,498
Construction Work in Progress	1,100,042	1,100,042	1,100,042
Less: Contributions for Extensions	(1,555,526)	(1,555,526)	(1,555,526)
Less: Accumulated Depreciation	(26,600,495)	(24,879,283)	(25,739,889)
	22,769,569	23,724,681	23,247,125
Materials & Supplies	1,672,935	1,672,935	1,672,935
			24,920,060
Cash Working Capital Allowance			1,531,207
RATE BASE			$ 26,451,267
Cash Working Capital Allowance:			
Operating Expenses, Test Year			$ 19,090,669
Deductions:			
Fuel for Generation			664,467
Purchased Electricity			8,457,990
Depreciation Expense			1,784,112
Tax Equivalency			1,821,777
Gross Utility Tax			164,305
Uncollectible Accounts			30,000
Total Deductions			12,922,651
Cash Operating Expenses			6,168,018
Cash Operating Expenses Ratio			1/8
Cash Operating Expenses Allowance (A)			771,002
Fuel for Generation			664,467
Purchased Electricity			8,457,990
Cash Fuel and Purchased Power Expenses			9,122,457
Cash Fuel and Purchased Power Ratio			1/12
Cash Fuel and Purchased Power Allowance (B)			760,205
Cash Working Capital Allowance (A plus B)			$ 1,531,207

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

BALANCE SHEETS
Rate Year Ended May 31, 2005

	ACTUAL Year Ended May 31, 2002	ACTUAL Test Year Ended May 31, 2003	FORECAST Year Ended May 31, 2004	FORECAST Rate Year Ended May 31, 2005
ASSETS				
FIXED ASSETS				
Assets	$ 40,412,141	$ 42,966,248	$ 49,059,448	$ 49,825,548
Construction Work in Progress	3,345,179	1,100,042	1,100,042	1,100,042
Less: Contributions for Extensions	(1,555,526)	(1,555,526)	(1,555,526)	(1,555,526)
Less: Accumulated Depreciation	(22,357,836)	(23,499,451)	(24,879,283)	(26,600,495)
	19,843,958	19,011,313	23,724,681	22,769,569
CURRENT ASSETS AND INVESTMENTS				
Cash and Investments	4,760,526	2,757,512	1,296,008	1,418,070
Materials and Supplies	1,705,016	1,640,854	1,672,935	1,672,935
Receivables	2,363,586	2,811,695	2,587,641	2,587,641
Less: Reserve for Uncollectibles	(360,616)	(386,036)	(373,326)	(373,326)
	8,468,512	6,824,025	5,183,258	5,305,320
TOTAL ASSETS	$ 28,312,470	$ 25,835,338	$ 28,907,939	$ 28,074,889
LIABILITIES AND SURPLUS				
LONG TERM DEBT				
Currently Outstanding	$ 8,930,850	$ 8,114,000	$ 7,299,200	$ 6,466,150
New Debt Issue Pro Forma			5,000,000	5,000,000
	8,930,850	8,114,000	12,299,200	11,466,150
CURRENT AND OTHER LIABILITIES				
Payables	2,052,204	2,384,451	2,218,328	2,218,328
Deferred Credits	2,946,476	946,476		
	4,998,680	3,330,927	2,218,328	2,218,328
TOTAL LIABILITIES	13,929,530	11,444,927	14,517,528	13,684,478
SURPLUS	14,382,940	14,390,411	14,390,411	14,390,411
TOTAL LIABILITIES AND SURPLUS	$ 28,312,470	$ 25,835,338	$ 28,907,939	$ 28,074,889

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

ASSETS AND ACCUMULATED DEPRECIATION

		ASSET COST							
		FYE 05/31/2003	FYE 05/31/2004			FYE 05/31/2005			
Account	Description	Balance	Additions	Less: Retirements	Balance	Pro Forma	Additions	Less: Retirements	Balance
311	Land & Land Rights	48,614			48,614	48,614			48,614
321	Structures & Improvements	3,242,079	94,000		3,336,079	3,336,079	60,000		3,396,079
342	Engine Dr. Gen.- IC	13,487,647	31,000		13,518,647	13,518,647			13,518,647
344	Accessory Equip- IC	1,459,325			1,459,325	1,459,325			1,459,325
345	Misc Plant Equip- IC	129,581	10,000		139,581	139,581	10,000		149,581
	PRODUCTION	18,367,246	135,000	0	18,502,246	18,502,246	70,000	0	18,572,246
352	Trans Substation Equip	5,536,804	31,000		5,567,804	5,567,804			5,567,804
352A	Trans Substation Equip	0			0	5,000,000			5,000,000
	TRANSMISSION	5,536,804	31,000	0	5,567,804	10,567,804	0	0	10,567,804
358	Poles, Towers, Fixtures	531,504	35,000	3,000	563,504	563,504	35,000	3,000	595,504
359	Underground Conduits	3,559,762	50,000		3,609,762	3,609,762	20,000		3,629,762
	POLES	4,091,266	85,000	3,000	4,173,266	4,173,266	55,000	3,000	4,225,266
363	Dist OH Conductors	2,514,080	201,000	2,100	2,712,980	2,712,980	75,000	1,500	2,786,480
364	Dist UG Conductors	4,036,105	277,000	3,200	4,309,905	4,309,905	100,000	5,000	4,404,905
365	Line Transformers	2,237,982	143,000	5,500	2,375,482	2,375,482	75,000	5,000	2,445,482
366	Overhead Services	595,772	30,000	600	625,172	625,172	30,000	1,000	654,172
367	Underground Services	409,653	64,000	1,200	472,453	472,453	50,000	1,000	521,453
368	Consumers' Meters	758,966	25,000	2,000	781,966	781,966	25,000	2,500	804,466
369	Consumers' Meter Install	125,700	4,000	1,100	128,600	128,600	4,000	1,000	131,600
	DISTRIBUTION	10,678,258	744,000	15,700	11,406,558	11,406,558	359,000	17,000	11,748,558
371	**Street Light & Signal Equip**	2,084,733	82,000	12,000	2,154,733	2,154,733	75,000	8,000	2,221,733
381	Office Equipment	1,127,361	10,000	200	1,137,161	1,137,161	175,000	5,000	1,307,161
382	Stores Equipment	52,634			52,634	52,634			52,634
384	Transportation Equipment	746,447			746,447	746,447	60,000	25,000	781,447
385	Communication Equipment	55,259	12,000	1,000	66,259	66,259	10,000	1,000	75,259
386	Laboratory Equipment	74,975	20,000	3,500	91,475	91,475	15,000	3,500	102,975
387	General Tools & Implements	118,733	10,000	400	128,333	128,333	10,000	400	137,933
391	Misc Tangible Property	32,532			32,532	32,532			32,532
	GENERAL	2,207,941	52,000	5,100	2,254,841	2,254,841	270,000	34,900	2,489,941
		42,966,248	1,129,000	35,800	44,059,448	49,059,448	829,000	62,900	49,825,548

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

ASSETS AND ACCUMULATED DEPRECIATION

			ACCUMULATED DEPRECIATION							
			FYE 05/31/2003	FYE 05/31/2004			FYE 05/31/2005			
		Annual Rate	Balance	Depreciation Expense	Less: Retirements	Balance	Pro Forma	Depreciation Expense	Less: Retirements	Balance
311	Land & Land Rights		0			0	0			0
321	Structures & Improvements	2.40%	1,242,223	78,938		1,321,161	1,321,161	80,786		1,401,947
342	Engine Dr. Gen.- IC	3.23%	9,536,927	436,152		9,973,079	9,973,079	436,652		10,409,731
344	Accessory Equip- IC	3.23%	956,832	47,136	0	1,003,968	1,003,968	47,136	0	1,051,104
345	Misc Plant Equip- IC	3.96%	127,779	5,329	0	133,108	133,108	5,725	0	138,833
	PRODUCTION		11,863,761	567,555	0	12,431,316	12,431,316	570,299	0	13,001,615
352	Trans Substation Equip	2.81%	1,233,948	156,020	0	1,389,968	1,389,968	156,455	0	1,546,423
352A	Trans Substation Equip	6.67%	0	0	0	0	0	333,333	0	333,333
	TRANSMISSION		1,233,948	156,020	0	1,389,968	1,389,968	489,788	0	1,879,756
358	Poles, Towers, Fixtures	5.52%	344,237	30,222	3,000	371,459	371,459	31,989	3,000	400,448
359	Underground Conduits	1.92%	1,645,769	68,827	0	1,714,596	1,714,596	69,499	0	1,784,095
	POLES		1,990,006	99,049	3,000	2,086,055	2,086,055	101,488	3,000	2,184,543
363	Dist OH Conductors	2.88%	803,493	75,270	2,100	876,663	876,663	79,192	1,500	954,355
364	Dist UG Conductors	2.76%	1,916,510	115,175	3,200	2,028,485	2,028,485	120,264	5,000	2,143,749
365	Line Transformers	2.10%	1,254,153	48,441	5,500	1,297,094	1,297,094	50,620	5,000	1,342,714
366	Overhead Services	5.04%	702,303	30,768	600	732,471	732,471	32,239	1,000	763,710
367	Underground Services	3.12%	231,626	13,761	1,200	244,187	244,187	15,505	1,000	258,692
368	Consumers' Meters	3.84%	577,155	29,586	2,000	604,741	604,741	30,459	2,500	632,700
369	Consumers' Meter Install	3.00%	52,916	3,815	1,100	55,631	55,631	3,903	1,000	58,534
	DISTRIBUTION		5,538,156	316,816	15,700	5,839,272	5,839,272	332,182	17,000	6,154,454
371	Street Light & Signal Equip	4.56%	1,703,468	96,660	12,000	1,788,128	1,788,128	99,783	8,000	1,879,911
381	Office Equipment	9.06%	310,692	102,583	200	413,075	413,075	110,728	5,000	518,803
382	Stores Equipment	3.84%	22,899	2,021	0	24,920	24,920	2,021	0	26,941
384	Transportation Equipment	8.28%	670,363	61,806	0	732,169	732,169	63,255	25,000	770,424
385	Communication Equipment	6.00%	33,329	3,646	1,000	35,975	35,975	4,246	1,000	39,221
386	Laboratory Equipment	2.76%	26,795	2,297	3,500	25,592	25,592	2,683	3,500	24,775
387	General Tools & Implements	4.80%	77,617	5,930	400	83,147	83,147	6,390	400	89,137
391	Misc Tangible Property	3.84%	28,417	1,249	0	29,666	29,666	1,249	0	30,915
	GENERAL		1,170,112	179,532	5,100	1,344,544	1,344,544	190,572	34,900	1,500,216
			23,499,451	1,415,632	35,800	24,879,283	24,879,283	1,784,112	62,900	26,600,495

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OTHER REVENUE
Rate Year Ended May 31, 2005

	NOTE	ACTUAL Test Year Ended May 31, 2003	ADJUSTMENT	FORECAST Rate Year Ended May 31, 2005
Street Lighting Rental		$159,996		$159,996
Misc Other Revenue	(A)	4,545	$5,200	9,745
Interest Income	(B)	73,857	(20,000)	53,857
Other Electric Income	(C)	2,004,197	(2,000,000)	4,197
		$2,242,595	($2,014,800)	$227,795

(A) Proposed increase in Reconnect Fees is forecast to increase Reconnect Fee revenue by $5,200, from $1,820 to $7,020.
(B) Estimated reduction in interest income due to lower cash balances.
(C) Eliminate $2 million NYPA refund from Revenue and from Expense. See Exhibit HSG-6, Schedule 3, Adjustment 6.

Exhibit No. ______
(HSG-7)

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - SUMMARY
Rate Year Ended May 31, 2005

Account Number	Description	Total	Production Expenses	Transmission Expenses	Maintenance- Poles	Distribution Expenses	St Light Expenses	Customer Accounts	General & Administrative	Non-Operating Expense
111	Regular Time	2,045,062	1,128,904	4,481		343,244	126,793	118,440	323,200	
112	Overtime	166,811	59,118	1,485		61,882	41,935	1,393	998	
115	Seasonal	515				27		488		
410	Supplies & Materials	186,916	73,618	1,521	2,053	24,049	32,086	280	53,309	
431	Telephone	26,072	672						25,400	
433	Water	20,222	20,222							
441	Publicity	4,638							4,638	
451	Printing	2,830				184		329	2,317	
452	Rentals	99,419	3,848	95,198		13			360	
455	Medical Fees	1,089							1,089	
459	Data Processing	14,845				675		9,863	4,307	
465	Insurance	174,248							174,248	
471	Postage	26,983						26,949	34	
472	Dues	4,547							4,547	
473	Travel	11,969							11,969	
474	Outside Legal	14,872							14,872	
475	Subscriptions	19,675							19,675	
476	Regulatory / PSC Expense	149,218							149,218	
477	Legal Notices	145							145	
478	MEUA Expenses	11,860							11,860	
484	Contract Services	537,553	467,338	50,000		2,755		8,491	8,969	
492	Professional Services	47,479							47,479	
495-498	Purchased Power	8,457,990	8,457,990							
608	Merchandise & Jobbing	(6,147)			(689)	(3,610)	(1,848)			
610	Material from Inventory	106,184	56,280			9,489	40,402	7	6	
620	Fuel Oil for Generation	207,934	207,934							
621	Natural Gas for Generation	456,533	456,533							
630	Ammonia from Inventory	1,197	1,197							
660	Inventory Overhead	54,705	24,197			5,788	24,671	45	4	
665	Depreciation	1,784,112	570,299	489,788	101,488	332,182	99,783		190,572	
670	Work Orders	(18,962)			689	7,583	(7)		(27,227)	
724	Payroll Reimb. Oper Munic.	620,708						146,235	474,473	
804	Transportation	87,084	7,421	410		34,040	13,328	16,977	14,908	
805	Building Services	41,477				8,295		24,887	8,295	
901	Tax Equivalency	1,821,777								1,821,777
902	Gross Utility Tax	188,478								188,478
903	A/R Consumers Bad Debt Exp	30,000								30,000

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - SUMMARY
Rate Year Ended May 31, 2005

Account Number	Description	Total	Production Expenses	Transmission Expenses	Maintenance- Poles	Distribution Expenses	St Light Expenses	Customer Accounts	General & Administrative	Non-Operating Expense
912	Consumers Deposit Interest	1,957							1,957	
929-939	Bond Interest	489,890								489,890
950	Expense Recovery	14,536							14,536	
800	Employee Benefits	547,338	295,406	1,415		98,703	40,500	30,058	81,256	
810	Retirement	360,000							360,000	
820	FICA	148,265							148,265	
830	Workers Compensation	34,434							34,434	
850	Dental / Medical	603,332							603,332	
860	Life Insurance	4,942							4,942	
	TOTALS	19,604,732	11,830,977	644,298	103,541	925,299	417,643	384,442	2,768,387	2,530,145
	Depreciation Expense	1,784,112	570,299	489,788	101,488	332,182	99,783	0	190,572	0
	Totals Without Depreciation	17,820,620	11,260,678	154,510	2,053	593,117	317,860	384,442	2,577,815	2,530,145

Production Expense	
Generation Costs	1,670,883
Fuel Generation	664,467
Purchased Electricity	8,457,990
Other Production Expense	467,338
	11,260,678

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - COMPARISON
Rate Year Ended May 31, 2005

Account Number	Description	Test Year Totals	Rate Year Totals	Increase (Decrease)	% Increase (Decrease)
111	Regular Time	$1,852,667	$2,045,062	$192,395	10.38%
112	Overtime	153,309	166,811	13,502	8.81%
115	Seasonal	485	515	30	6.19%
410	Supplies & Materials	176,054	186,916	10,862	6.17%
431	Telephone	24,557	26,072	1,515	6.17%
433	Water	19,047	20,222	1,175	6.17%
441	Publicity	4,368	4,638	270	6.18%
451	Printing	2,665	2,830	165	6.19%
452	Rentals	93,641	99,419	5,778	6.17%
455	Medical Fees	1,026	1,089	63	6.14%
459	Data Processing	13,983	14,845	862	6.16%
465	Insurance	164,122	174,248	10,126	6.17%
471	Postage	25,415	26,983	1,568	6.17%
472	Dues	4,283	4,547	264	6.16%
473	Travel	11,273	11,969	696	6.17%
474	Outside Legal	14,008	14,872	864	6.17%
475	Subscriptions	18,532	19,675	1,143	6.17%
476	Regulatory / PSC Expense	46,358	149,218	102,860	221.88%
477	Legal Notices	137	145	8	5.84%
478	MEUA Expenses	11,171	11,860	689	6.17%
484	Contract Services	2,460,394	537,553	(1,922,841)	-78.15%
492	Professional Services	44,720	47,479	2,759	6.17%
495-498	Purchased Power	8,504,755	8,457,990	(46,765)	-0.55%
608	Merchandise & Jobbing	(5,790)	(6,147)	(357)	6.17%
610	Material from Inventory	100,014	106,184	6,170	6.17%
620	Fuel Oil for Generation	207,934	207,934	0	0.00%
621	Natural Gas for Generation	456,533	456,533	(0)	0.00%
630	Ammonia from Inventory	1,127	1,197	70	6.21%
660	Inventory Overhead	51,526	54,705	3,179	6.17%
665	Depreciation	1,243,209	1,784,112	540,903	43.51%
670	Work Orders	(17,861)	(18,962)	(1,101)	6.16%
724	Payroll Reimb. Oper Munic.	585,076	620,708	35,632	6.09%

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - COMPARISON
Rate Year Ended May 31, 2005

Account Number	Description	Test Year Totals	Rate Year Totals	Increase (Decrease)	% Increase (Decrease)
804	Transportation	82,023	87,084	5,061	6.17%
805	Building Services	39,067	41,477	2,410	6.17%
901	Tax Equivalency	1,624,411	1,821,777	197,366	12.15%
902	Gross Utility Tax	165,653	188,478	22,825	13.78%
903	A/R Consumers Bad Debt Exp	25,529	30,000	4,471	17.51%
912	Consumers Deposit Interest	1,957	1,957	0	0.00%
929-939	Bond Interest	489,890	489,890	0	0.00%
950	Expense Recovery	14,536	14,536	0	0.00%
800	Employee Benefits	496,294	547,338	51,044	10.29%
810	Retirement	36,584	360,000	323,416	884.04%
820	FICA	134,322	148,265	13,943	10.38%
830	Workers Compensation	31,196	34,434	3,238	10.38%
850	Dental / Medical	407,271	603,332	196,061	48.14%
860	Life Insurance	4,069	4,942	873	21.45%
	TOTALS	19,821,540	19,604,732	($216,808)	-1.09%
	Less: Bond Interest	489,890	489,890		
	ELECTRIC OPERATING EXPENSES	$19,331,650	$19,114,842		

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - ADJUSTMENTS
Rate Year Ended May 31, 2005

	Description	Additional Information
1	Adj. 1- Civil Service Association PR increase, Rate Year over Test Year = 6.09%.	Contractual increase in Civil Service Association payroll of 3% annually, effective June 1, 2003 through May 31, 2006. Increase of Rate Year over Test Year is 6%.
1A	Adj. 1A- Change is proportional to increase in Regular Time payroll.	
1B	Adj. 1B- Contractual increase in Life Insurance of 10.00%.	
2	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	General CPI-related inflationary increase of 3.04% annually, per CPI Schedule. Increase of Rate Year over Test Year is 6.17%.
3	Adj. 3- Dental / Medical costs increase, Rate Year over Test Year = 42.04%.	Increase in Dental / Medical costs per NYS fund of 19.18% annually. Increase of Rate Year over Test Year is 42.04%.
4	Adj. 4- Rate Year Amount from Production Costs, HSG-3, Schedule 1.	Production Costs are computed on Production Costs schedule.
5	Adj. 5- Rate Year Amounts from Assets and Accumulated Depreciation, HSG-6, Schedule 4.	Depreciation expense is computed on Assets and Accumulated Depreciation schedule.
6	Adj. 6- Eliminate $2 million NYPA refund from Revenue and from Expense.	Eliminate non-recurring Test Year item.
7	Adj. 7- Tax Equivalency increases based on real estate tax rate increases. Increase of Rate Year over Test Year = 12.15%.	Tax Equivalency increases are based on increases in Village real estate tax rate. Increase is 5.9% for 2004 over 2003, estimated at 5.9% for 2005 over 2003.
8	Adj. 8- Rate Year Amount from Retirement Costs, HSG-7, Schedule 5.	Retirement cost expense is computed on Retirement Costs schedule.
9	Adj. 9- Estimated Bad Debts Expense.	
10	Adj. 10- Additional testing required for new substation.	
11	Adj. 11- Additional payroll costs related to NYISO purchasing.	
12	Adj. 12- Rate Case costs amortized over 2 years.	

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS- CPI INFLATOR
Rate Year Ended May 31, 2005

	2001-2002	2002-2003	Increase
October	187.8	193.7	3.14%
November	187.8	193.4	2.98%
December	187.3	193.1	3.10%
January	188.5	194.7	3.29%
February	189.9	196.2	3.32%
March	191.1	197.1	3.14%
April	191.8	196.7	2.55%
May	191.4	196.8	2.82%
June	191.5	196.9	2.82%
July	192.0	197.7	2.97%
August	193.1	199.1	3.11%
September	193.3	199.6	3.26%
Average			3.04%

Source: Bureau of Labor Statistics, Series ID CUURA101SA0, Not Seasonally Adjusted (All Urban Consumers, New York-Northern New Jersey-Long Island, NY-NJ-CT-PA).

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - RETIREMENT COSTS
Rate Year Ended May 31, 2005

	Tier 1	Tier 2	Tier 3	Tier 4	Total
Estimated Salaries, 2003-2004	169,390	87,615	650,366	1,982,370	2,889,741
Multiplier for 2004-2005	0.94	0.97	0.99	1.08	
Estimated Salaries, 2004-2005	159,227	84,987	643,862	2,140,960	3,029,035
Contribution Percentages					
Regular Pension	16.8%	14.3%	11.0%	11.0%	
GTLI Pension	0.4%	0.4%	0.4%	0.4%	
Sick Leave	0.1%	0.1%	0.1%	0.1%	
	17.3%	14.8%	11.5%	11.5%	
Contribution Amounts					
Regular Pension	26,750	12,153	70,825	235,506	345,234
GTLI Pension	637	340	2,575	8,564	12,116
Sick Leave	159	85	644	2,141	3,029
Retirement Expense	27,546	12,578	74,044	246,211	360,379
Rounded to					360,000

Retirement costs are computed based on information from New York State and Local Retirement System for December 15, 2004 payments.

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - PRODUCTION EXPENSES
Rate Year Ended May 31, 2005

Acct. No.	Description	Production Expenses- Test Year Actual	Adjustments	Change Amount	Production Expenses- Rate Year
111	Regular Time	989,100	Adj. 1- Civil Service Association PR increase, Rate Year over Test Year = 6.09%. Adj. 11- Additional payroll costs related to NYISO purchasing.	139,804	1,128,904
112	Overtime	51,797	Adj. 1A- Change is proportional to increase in Regular Time payroll.	7,321	59,118
115	Seasonal				
410	Supplies & Materials	69,340	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	4,278	73,618
431	Telephone	633	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	39	672
433	Water	19,047	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	1,175	20,222
441	Publicity				
451	Printing				
452	Rentals	3,624	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	224	3,848
455	Medical Fees				
459	Data Processing				
465	Insurance				
471	Postage				
472	Dues				
473	Travel				
474	Outside Legal				
475	Subscriptions				
476	Regulatory / PSC Expens				
477	Legal Notices				
478	MEUA Expenses				
484	Contract Services	2,440,179	Adj. 6- Eliminate $2 million NYPA refund from Revenue and from Expense. Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	(1,972,841)	467,338
492	Professional Services				
495-498	Purchased Power	8,504,755	Adj. 4- Rate Year Amount from Production Costs, HSG-3, Schedule 1.	(46,765)	8,457,990
608	Merchandise & Jobbing				

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - PRODUCTION EXPENSES
Rate Year Ended May 31, 2005

Acct. No.	Description	Production Expenses- Test Year Actual	Adjustments	Change Amount	Production Expenses- Rate Year
610	Material from Inventory	53,009	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	3,271	56,280
620	Fuel Oil for Generation	207,934	Adj. 4- Rate Year Amount from Production Costs, HSG-3, Schedule 1.	0	207,934
621	Natural Gas for Generatic	456,533	Adj. 4- Rate Year Amount from Production Costs, HSG-3, Schedule 1.	(0)	456,533
630	Ammonia from Inventory	1,127	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	70	1,197
660	Inventory Overhead	22,791	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	1,406	24,197
665	Depreciation	519,097	Adj. 5- Rate Year Amounts from Assets and Accumulated Depreciation, HSG-6, Schedule 4.	51,202	570,299
670	Work Orders				
724	Payroll Reimb. Oper Muni				
804	Transportation	6,990	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	431	7,421
805	Building Services				
901	Tax Equivalency				
902	Gross Utility Tax				
903	A/R Consumers Bad Deb				
912	Consumers Deposit Intere				
929-939	Bond Interest				
950	Expense Recovery				
800	Employee Benefits	258,823	Adj. 1A- Change is proportional to increase in Regular Time payroll.	36,583	295,406
810	Retirement				
820	FICA				
830	Workers Compensation				
850	Dental / Medical				
860	Life Insurance				
	TOTALS	13,604,779		(1,773,802)	11,830,977
	Depreciation Expense	519,097		51,202	570,299
	Totals Without Depreciati	13,085,682		(1,825,004)	11,260,678

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - TRANSMISSION EXPENSES
Rate Year Ended May 31, 2005

Acct. No.	Description	Transmission Expenses- Test Year Actual	Adjustments	Change Amount	Transmission Expenses- Rate Year
111	Regular Time	4,224	Adj. 1- Civil Service Association PR increase, Rate Year over Test Year = 6.09%.	257	4,481
112	Overtime	1,400	Adj. 1A- Change is proportional to increase in Regular Time payroll.	85	1,485
115	Seasonal				
410	Supplies & Materials	1,433	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	88	1,521
431	Telephone				
433	Water				
441	Publicity				
451	Printing				
452	Rentals	89,666	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	5,532	95,198
455	Medical Fees				
459	Data Processing				
465	Insurance				
471	Postage				
472	Dues				
473	Travel				
474	Outside Legal				
475	Subscriptions				
476	Regulatory / PSC Expens				
477	Legal Notices				
478	MEUA Expenses				
484	Contract Services		Adj. 10- Additional testing required for new substation.	50,000	50,000
492	Professional Services				
495-498	Purchased Power				
608	Merchandise & Jobbing				
610	Material from Inventory				
620	Fuel Oil for Generation				
621	Natural Gas for Generatic				
630	Ammonia from Inventory				

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - TRANSMISSION EXPENSES
Rate Year Ended May 31, 2005

Acct. No.	Description	Transmission Expenses- Test Year Actual	Adjustments	Change Amount	Transmission Expenses- Rate Year
660	Inventory Overhead				
665	Depreciation	120,649	Adj. 5- Rate Year Amounts from Assets and Accumulated Depreciation, HSG-6, Schedule 4.	369,139	489,788
670	Work Orders				
724	Payroll Reimb. Oper Mun				
804	Transportation	386	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	24	410
805	Building Services				
901	Tax Equivalency				
902	Gross Utility Tax				
903	A/R Consumers Bad Deb				
912	Consumers Deposit Inter				
929-939	Bond Interest				
950	Expense Recovery				
800	Employee Benefits	1,334	Adj. 1A- Change is proportional to increase in Regular Time payroll.	81	1,415
810	Retirement				
820	FICA				
830	Workers Compensation				
850	Dental / Medical				
860	Life Insurance				
	TOTALS	219,092		425,206	644,298
	Depreciation Expense	120,649		369,139	489,788
	Totals Without Depreciati	98,443		56,067	154,510

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - POLES EXPENSES
Rate Year Ended May 31, 2005

Acct. No.	Description	Proles Expenses-Test Year Actual	Adjustments	Change Amount	Poles Expenses-Rate Year
111	Regular Time				
112	Overtime				
115	Seasonal				
410	Supplies & Materials	1,934	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	119	2,053
431	Telephone				
433	Water				
441	Publicity				
451	Printing				
452	Rentals				
455	Medical Fees				
459	Data Processing				
465	Insurance				
471	Postage				
472	Dues				
473	Travel				
474	Outside Legal				
475	Subscriptions				
476	Regulatory / PSC Expens				
477	Legal Notices				
478	MEUA Expenses				
484	Contract Services				
492	Professional Services				
495-498	Purchased Power				
608	Merchandise & Jobbing	(649)	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	(40)	(689)
610	Material from Inventory				
620	Fuel Oil for Generation				
621	Natural Gas for Generatic				
630	Ammonia from Inventory				
660	Inventory Overhead				

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - POLES EXPENSES
Rate Year Ended May 31, 2005

Acct. No.	Description	Proles Expenses- Test Year Actual	Adjustments	Change Amount	Poles Expenses- Rate Year
665	Depreciation	92,588	Adj. 5- Rate Year Amounts from Assets and Accumulated Depreciation, HSG-6, Schedule 4.	8,900	101,488
670	Work Orders	649	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	40	689
724	Payroll Reimb. Oper Mun				
804	Transportation				
805	Building Services				
901	Tax Equivalency				
902	Gross Utility Tax				
903	A/R Consumers Bad Deb				
912	Consumers Deposit Inter				
929-939	Bond Interest				
950	Expense Recovery				
800	Employee Benefits				
810	Retirement				
820	FICA				
830	Workers Compensation				
850	Dental / Medical				
860	Life Insurance				
	TOTALS	94,522		9,019	103,541
	Depreciation Expense	92,588		8,900	101,488
	Totals Without Depreciati	1,934		119	2,053

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - DISTRIBUTION EXPENSES
Rate Year Ended May 31, 2005

Acct. No.	Description	Distribution Expenses- Test Year Actual	Adjustments	Change Amount	Distribution Expenses- Rate Year
111	Regular Time	323,540	Adj. 1- Civil Service Association PR increase, Rate Year over Test Year = 6.09%.	19,704	343,244
112	Overtime	58,330	Adj. 1A- Change is proportional to increase in Regular Time payroll.	3,552	61,882
115	Seasonal	25	Adj. 1A- Change is proportional to increase in Regular Time payroll.	2	27
410	Supplies & Materials	22,651	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	1,398	24,049
431	Telephone				
433	Water				
441	Publicity				
451	Printing	173	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	11	184
452	Rentals	12	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	1	13
455	Medical Fees				
459	Data Processing	636	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	39	675
465	Insurance				
471	Postage				
472	Dues				
473	Travel				
474	Outside Legal				
475	Subscriptions				
476	Regulatory / PSC Expens				
477	Legal Notices				
478	MEUA Expenses				
484	Contract Services	2,755	Adj. 6- Eliminate $2 million NYPA refund from Revenue and from Expense. Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.		2,755
492	Professional Services				
495-498	Purchased Power				
608	Merchandise & Jobbing	(3,400)	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	(210)	(3,610)

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - DISTRIBUTION EXPENSES
Rate Year Ended May 31, 2005

Acct. No.	Description	Distribution Expenses- Test Year Actual	Adjustments	Change Amount	Distribution Expenses- Rate Year
610	Material from Inventory	8,938	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	551	9,489
620	Fuel Oil for Generation				
621	Natural Gas for Generatic				
630	Ammonia from Inventory				
660	Inventory Overhead	5,452	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	336	5,788
665	Depreciation	314,967	Adj. 5- Rate Year Amounts from Assets and Accumulated Depreciation, HSG-6, Schedule 4.	17,215	332,182
670	Work Orders	7,142	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	441	7,583
724	Payroll Reimb. Oper Muni				
804	Transportation	32,062	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	1,978	34,040
805	Building Services	7,813	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	482	8,295
901	Tax Equivalency				
902	Gross Utility Tax				
903	A/R Consumers Bad Deb				
912	Consumers Deposit Intere				
929-939	Bond Interest				
950	Expense Recovery				
800	Employee Benefits	93,037	Adj. 1A- Change is proportional to increase in Regular Time payroll.	5,666	98,703
810	Retirement				
820	FICA				
830	Workers Compensation				
850	Dental / Medical				
860	Life Insurance				
	TOTALS	874,133		51,166	925,299
	Depreciation Expense	314,967		17,215	332,182
	Totals Without Depreciati	559,166		33,951	593,117

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - STREET LIGHTING EXPENSES
Rate Year Ended May 31, 2005

Acct. No.	Description	Street Lighting Expenses- Test Year Actual	Adjustments	Change Amount	Street Lighting Expenses- Rate Year
111	Regular Time	119,515	Adj. 1- Civil Service Association PR increase, Rate Year over Test Year = 6.09%.	7,278	126,793
112	Overtime	39,528	Adj. 1A- Change is proportional to increase in Regular Time payroll.	2,407	41,935
115	Seasonal				
410	Supplies & Materials	30,221	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	1,865	32,086
431	Telephone				
433	Water				
441	Publicity				
451	Printing				
452	Rentals				
455	Medical Fees				
459	Data Processing				
465	Insurance				
471	Postage				
472	Dues				
473	Travel				
474	Outside Legal				
475	Subscriptions				
476	Regulatory / PSC Expens				
477	Legal Notices				
478	MEUA Expenses				
484	Contract Services				
492	Professional Services				
495-498	Purchased Power				
608	Merchandise & Jobbing	(1,741)	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	(107)	(1,848)
610	Material from Inventory	38,054	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	2,348	40,402
620	Fuel Oil for Generation				
621	Natural Gas for Generatic				

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - STREET LIGHTING EXPENSES
Rate Year Ended May 31, 2005

Acct. No.	Description	Street Lighting Expenses- Test Year Actual	Adjustments	Change Amount	Street Lighting Expenses- Rate Year
630	Ammonia from Inventory				
660	Inventory Overhead	23,237	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	1,434	24,671
665	Depreciation	92,681	Adj. 5- Rate Year Amounts from Assets and Accumulated Depreciation, HSG-6, Schedule 4.	7,102	99,783
670	Work Orders	(7)	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.		(7)
724	Payroll Reimb. Oper Mun				
804	Transportation	12,553	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	775	13,328
805	Building Services				
901	Tax Equivalency				
902	Gross Utility Tax				
903	A/R Consumers Bad Deb				
912	Consumers Deposit Inter				
929-939	Bond Interest				
950	Expense Recovery				
800	Employee Benefits	38,175	Adj. 1A- Change is proportional to increase in Regular Time payroll.	2,325	40,500
810	Retirement				
820	FICA				
830	Workers Compensation				
850	Dental / Medical				
860	Life Insurance				
	TOTALS	392,216		25,427	417,643
	Depreciation Expense	92,681		7,102	99,783
	Totals Without Depreciati	299,535		18,325	317,860

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - CUSTOMER ACCOUNTS EXPENSES
Rate Year Ended May 31, 2005

Acct. No.	Description	Customer Accounts Expenses- Test Year	Adjustments	Change Amount	Customer Accounts Expenses- Rate Year
111	Regular Time	111,641	Adj. 1- Civil Service Association PR increase, Rate Year over Test Year = 6.09%.	6,799	118,440
112	Overtime	1,313	Adj. 1A- Change is proportional to increase in Regular Time payroll.	80	1,393
115	Seasonal	460	Adj. 1A- Change is proportional to increase in Regular Time payroll.	28	488
410	Supplies & Materials	264	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	16	280
431	Telephone				
433	Water				
441	Publicity				
451	Printing	310	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	19	329
452	Rentals				
455	Medical Fees				
459	Data Processing	9,290	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	573	9,863
465	Insurance				
471	Postage	25,383	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	1,566	26,949
472	Dues				
473	Travel				
474	Outside Legal				
475	Subscriptions				
476	Regulatory / PSC Expens				
477	Legal Notices				
478	MEUA Expenses				
484	Contract Services	8,491	Adj. 6- Eliminate $2 million NYPA refund from Revenue and from Expense. Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.		8,491
492	Professional Services				
495-498	Purchased Power				

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - CUSTOMER ACCOUNTS EXPENSES
Rate Year Ended May 31, 2005

Acct. No.	Description	Customer Accounts Expenses-Test Year	Adjustments	Change Amount	Customer Accounts Expenses-Rate Year
608	Merchandise & Jobbing				
610	Material from Inventory	7	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.		7
620	Fuel Oil for Generation				
621	Natural Gas for Generatic				
630	Ammonia from Inventory				
660	Inventory Overhead	42	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	3	45
665	Depreciation				
670	Work Orders				
724	Payroll Reimb. Oper Mun	137,840	Adj. 1A- Change is proportional to increase in Regular Time payroll.	8,395	146,235
804	Transportation	15,990	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	987	16,977
805	Building Services	23,441	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	1,446	24,887
901	Tax Equivalency				
902	Gross Utility Tax				
903	A/R Consumers Bad Deb				
912	Consumers Deposit Inter				
929-939	Bond Interest				
950	Expense Recovery				
800	Employee Benefits	28,333	Adj. 1A- Change is proportional to increase in Regular Time payroll.	1,725	30,058
810	Retirement				
820	FICA				
830	Workers Compensation				
850	Dental / Medical				
860	Life Insurance				
	TOTALS	362,805		21,637	384,442
	Depreciation Expense	0		0	0
	Totals Without Depreciati	362,805		21,637	384,442

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - GENERAL & ADMINISTRATIVE EXPENSES
Rate Year Ended May 31, 2005

Acct. No.	Description	General & Administrative Expenses- Test Year Actual	Adjustments	Change Amount	General & Administrative Expenses- Rate Year
111	Regular Time	304,647	Adj. 1- Civil Service Association PR increase, Rate Year over Test Year = 6.09%.	18,553	323,200
112	Overtime	941	Adj. 1A- Change is proportional to increase in Regular Time payroll.	57	998
115	Seasonal				
410	Supplies & Materials	50,211	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	3,098	53,309
431	Telephone	23,924	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	1,476	25,400
433	Water				
441	Publicity	4,368	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	270	4,638
451	Printing	2,182	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	135	2,317
452	Rentals	339	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	21	360
455	Medical Fees	1,026	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	63	1,089
459	Data Processing	4,057	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	250	4,307
465	Insurance	164,122	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	10,126	174,248
471	Postage	32	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	2	34
472	Dues	4,283	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	264	4,547
473	Travel	11,273	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	696	11,969
474	Outside Legal	14,008	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	864	14,872

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - GENERAL & ADMINISTRATIVE EXPENSES
Rate Year Ended May 31, 2005

Acct. No.	Description	General & Administrative Expenses-Test Year Actual	Adjustments	Change Amount	General & Administrative Expenses-Rate Year
475	Subscriptions	18,532	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	1,143	19,675
476	Regulatory / PSC Expens	46,358	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%. Adj. 12- Rate Case costs amortized over 2 years.	102,860	149,218
477	Legal Notices	137	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	8	145
478	MEUA Expenses	11,171	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	689	11,860
484	Contract Services	8,969	Adj. 6- Eliminate $2 million NYPA refund from Revenue and from Expense. Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.		8,969
492	Professional Services	44,720	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	2,759	47,479
495-498	Purchased Power				
608	Merchandise & Jobbing				
610	Material from Inventory	6	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.		6
620	Fuel Oil for Generation				
621	Natural Gas for Generatic				
630	Ammonia from Inventory				
660	Inventory Overhead	4	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.		4
665	Depreciation	103,227	Adj. 5- Rate Year Amounts from Assets and Accumulated Depreciation, HSG-6, Schedule 4.	87,345	190,572
670	Work Orders	(25,645)	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	(1,582)	(27,227)
724	Payroll Reimb. Oper Mun	447,236	Adj. 1A- Change is proportional to increase in Regular Time payroll.	27,237	474,473

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - GENERAL & ADMINISTRATIVE EXPENSES
Rate Year Ended May 31, 2005

Acct. No.	Description	General & Administrative Expenses- Test Year Actual	Adjustments	Change Amount	General & Administrative Expenses- Rate Year
804	Transportation	14,042	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	866	14,908
805	Building Services	7,813	Adj. 2- CPI inflationary increase from HSG-7, Schedule 4, Rate Year over Test Year = 6.17%.	482	8,295
901	Tax Equivalency				
902	Gross Utility Tax				
903	A/R Consumers Bad Deb				
912	Consumers Deposit Inter	1,957			1,957
929-939	Bond Interest				
950	Expense Recovery	14,536			14,536
800	Employee Benefits	76,592	Adj. 1A- Change is proportional to increase in Regular Time payroll.	4,664	81,256
810	Retirement	36,584	Adj. 8- Rate Year Amount from Retirement Costs, HSG-7, Schedule 5.	323,416	360,000
820	FICA	134,322	Adj. 1A- Change is proportional to increase in Regular Time payroll.	13,943	148,265
830	Workers Compensation	31,196	Adj. 1A- Change is proportional to increase in Regular Time payroll.	3,238	34,434
850	Dental / Medical	407,271	Adj. 1A- Change is proportional to increase in Regular Time payroll. Adj. 3- Dental / Medical costs increase, Rate Year over Test Year = 42.04%.	196,061	603,332
860	Life Insurance	4,070	Adj. 1A- Change is proportional to increase in Regular Time payroll. Adj. 1B- Contractual increase in Life Insurance of 10.00%.	872	4,942
	TOTALS	1,968,511		799,876	2,768,387
	Depreciation Expense	103,227		87,345	190,572
	Totals Without Depreciati	1,865,284		712,531	2,577,815

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - NON-OPERATING EXPENSES
Rate Year Ended May 31, 2005

Acct. No.	Description	Non-Operating Expenses- Test Year Actual	Adjustments	Change Amount	Non-Operating Expenses- Rate Year
111	Regular Time				
112	Overtime				
115	Seasonal				
410	Supplies & Materials				
431	Telephone				
433	Water				
441	Publicity				
451	Printing				
452	Rentals				
455	Medical Fees				
459	Data Processing				
465	Insurance				
471	Postage				
472	Dues				
473	Travel				
474	Outside Legal				
475	Subscriptions				
476	Regulatory / PSC Expens				
477	Legal Notices				
478	MEUA Expenses				
484	Contract Services				
492	Professional Services				
495-498	Purchased Power				
608	Merchandise & Jobbing				
610	Material from Inventory				
620	Fuel Oil for Generation				
621	Natural Gas for Generatic				
630	Ammonia from Inventory				
660	Inventory Overhead				
665	Depreciation				

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

OPERATING EXPENSE DETAILS - NON-OPERATING EXPENSES
Rate Year Ended May 31, 2005

Acct. No.	Description	Non-Operating Expenses- Test Year Actual	Adjustments	Change Amount	Non-Operating Expenses- Rate Year
670	Work Orders				
724	Payroll Reimb. Oper Mun				
804	Transportation				
805	Building Services				
901	Tax Equivalency	1,624,411	Adj. 7- Tax Equivalency increases based on real estate tax rate increases. Increase of Rate Year over Test Year = 12.15%.	197,366	1,821,777
902	Gross Utility Tax	165,653	See Exhibit HSG-5, Schedule 1.	22,825	188,478
903	A/R Consumers Bad Deb	25,529	Adj. 9- Estimated Bad Debts Expense.	4,471	30,000
912	Consumers Deposit Inter				
929-939	Bond Interest	489,890			489,890
950	Expense Recovery				
800	Employee Benefits				
810	Retirement				
820	FICA				
830	Workers Compensation				
850	Dental / Medical				
860	Life Insurance				
	TOTALS	2,305,483		224,662	2,530,145
	Depreciation Expense	0		0	0
	Totals Without Depreciati	2,305,483		224,662	2,530,145

Exhibit No. ______
(MS-1)

Exhibit No.___
(MS-1)

Moody's Investors Service
Global Credit Research

Municipal Credit Research
New Issue
Published 22 Jul 2003

Rockville Centre (Village of) NY

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Moody's Rating

Issue		Rating
Public Improvement Serial Bonds, 2003		Aa3
Sale Amount	$1,200,000	
Expected Sale Date	07/24/03	
Rating Description	General Obligation Unlimited Tax Pledge	

MOODY'S ASSIGNS AN Aa3 RATING TO THE VILLAGE OF ROCKVILLE CENTRE'S (NY) $1.2 MILLION PUBLIC IMPROVEMENT SERIAL BONDS - 2003

AFFIRMS Aa3 RATING ON $27.7 MILLION IN PARITY DEBT, INCLUDING CURRENT ISSUE

Opinion

Moody's Investors Service has assigned an Aa3 rating to the Village of Rockville Centre's (NY) $1.2 million Public Improvement Serial Bonds - 2003. Moody's has also affirmed the Aa3 rating on the village's $27.7 million in parity debt, including the current issue. The bonds are secured by the village's unlimited tax pledge and will finance street resurfacing and drainage. The Aa3 rating reflects the village's narrow but well managed financial operations; a mature, wealthy residential tax base; and manageable debt position.

NARROW BUT WELL MANAGED FINANCIAL OPERATIONS

Moody's expects the village's financial operations to remain satisfactory given a track record of timely tax rate increases, strong budgetary control and management's commitment to maintain adequate reserves. The village has traditionally maintained General Fund reserves at a relatively modest 5% of revenues or less, ending fiscal 2002 with a General Fund balance of $1.2 million (4.9% of operating revenues). Unaudited results for fiscal 2003 indicate an increased General Fund balance of approximately $1.9 million (a satisfactory 7.6% of revenues), largely driven by a $400,000 transfer to undesignated reserves out of a $2 million revenue generated from the settlement of litigation involving the Town of Hempstead's (rated Aa2) solid waste facility. Fiscal 2003 undesignated General Fund balance is (unaudited) \$1.7 million (6.8% of revenues) and management has expressed its commitment to maintain undesignated reserves at a minimum of 5% of annual revenues. Operating revenues are derived primarily from property taxes (60%), with strong collections.

While the tax base has been stagnant for a number of years because of ongoing tax appeals, officials annually increase tax rates sufficient to support operations. Also, the village's successful municipal electric and water utilities provide some diversity to the General Fund revenue base with utility PILOTs and chargebacks accounting for 12% of revenues. The self-supporting electric utility provides service to residents at rates below those charged by LIPA.

MATURE RESIDENTIAL SUBURB WITH FAVORABLE WEALTH INDICIES

Moody's expects that this residential village will continue to derive strength from its affluent \$2.6 billion tax base despite incremental declines in assessed values due to ongoing tax certiorari claims. Located in Nassau County (rated Baa2), the village's residents benefit from easy access to employment centers the New York City metropolitan area. Ongoing tax certiorari claims have offset increases from redevelopment of residential property. Full value, however, has increased an average of 11.6% annually since 2000, indicative of strong market value appreciation. A strong resident demographic profile is reflected by per capita and median family incomes of 174% and 200% (respectively) of state averages and a high value per capita of \$107,225.

MANAGEABLE DEBT POSITION

Moody's expects the village's debt position will remain manageable given its low direct debt burden, rapid payout of debt and lack of significant future debt plans. The village's direct debt burden (exclusive of self-supporting debt) is a low 0.5% of full value and increases to an average 2.9% on an overall basis. Debt is amortized at a rapid rate, with 80.3% of principal retired in 10 years. Management reports limited future debt plans, including \$5 million to finance the construction of an electric substation, which will not appreciably increase the debt burden.

KEY STATISTICS:

Post-sale Parity Debt Outstanding: \$27.7 Million

2000 population: 24568

2001 full value: \$2.6 billion

2002 full value per capita: \$107,225

1999 Per Capita Income as a % of State: 174%

1999 Median Family Income as a % of State: 200%

Direct debt burden: 0.5%

Overall adjusted debt burden: 2.9%

Payout of principal (10 years): 80.3%

2002 General Fund balance: \$1.2 million (4.9% of General Fund revenues)

2003 unaudited General Fund balance: \$1.9 million (7.6% of General Fund revenues)

Exhibit No. ______
(MS-2)

INCORPORATED VILLAGE OF ROCKVILLE CENTRE

COMPARISON OF FINANCING ALTERNATIVES ($000 except per kWh)

	15 Year Maturity				30 Year Maturity			
	Interest Rate			4.50%	Interest Rate			5.25%
Year Ended May 31	Principal	Interest	Total Payments	Outstanding, End of Year	Principal	Interest	Total Payments	Outstanding, End of Year
2004				5,000,000				5,000,000
2005	333,333	225,000	558,333	4,666,667	166,667	262,500	429,167	4,833,333
2006	333,333	210,000	543,333	4,333,334	166,667	253,750	420,417	4,666,666
2007	333,333	195,000	528,333	4,000,001	166,667	245,000	411,667	4,499,999
2008	333,333	180,000	513,333	3,666,668	166,667	236,250	402,917	4,333,332
2009	333,333	165,000	498,333	3,333,335	166,667	227,500	394,167	4,166,665
2010	333,333	150,000	483,333	3,000,002	166,667	218,750	385,417	3,999,998
2011	333,333	135,000	468,333	2,666,669	166,667	210,000	376,667	3,833,331
2012	333,333	120,000	453,333	2,333,336	166,667	201,250	367,917	3,666,664
2013	333,333	105,000	438,333	2,000,003	166,667	192,500	359,167	3,499,997
2014	333,333	90,000	423,333	1,666,670	166,667	183,750	350,417	3,333,330
2015	333,333	75,000	408,333	1,333,337	166,667	175,000	341,667	3,166,663
2016	333,333	60,000	393,333	1,000,004	166,667	166,250	332,917	2,999,996
2017	333,333	45,000	378,333	666,671	166,667	157,500	324,167	2,833,329
2018	333,333	30,000	363,333	333,338	166,667	148,750	315,417	2,666,662
2019	333,333	15,000	348,333	5	166,667	140,000	306,667	2,499,995
2020	5	0	5	0	166,667	131,250	297,917	2,333,328
2021	0	0	0	0	166,667	122,500	289,167	2,166,661
2022	0	0	0	0	166,667	113,750	280,417	1,999,994
2023	0	0	0	0	166,667	105,000	271,667	1,833,327
2024	0	0	0	0	166,667	96,250	262,917	1,666,660
2025	0	0	0	0	166,667	87,500	254,167	1,499,993
2026	0	0	0	0	166,667	78,750	245,417	1,333,326
2027	0	0	0	0	166,667	70,000	236,667	1,166,659
2028	0	0	0	0	166,667	61,250	227,917	999,992
2029	0	0	0	0	166,667	52,500	219,167	833,325
2030	0	0	0	0	166,667	43,750	210,417	666,658
2031	0	0	0	0	166,667	35,000	201,667	499,991
2032	0	0	0	0	166,667	26,250	192,917	333,324
2033	0	0	0	0	166,667	17,500	184,167	166,657
2034	0	0	0	0	166,657	8,749	175,406	0
	5,000,000	1,800,000	6,800,000		5,000,000	4,068,749	9,068,749	
kWh			196,573,180				196,573,180	
Cost per annual kWh- over 30 yeai			$0.0346				$0.0461	
Average Annual Residential Usage			10,172				10,172	
30-Year Residential Cost			$352				$469	
Average Annual Commercial Usag			125,999				125,999	
30-Year Commercial Cost			$4,360				$5,809	

Exhibit No. ______
(MM-1)

MICHAEL S. MARKS
Senior Vice President

SUMMARY OF QUALIFICATIONS

Mr. Marks has twenty-three years of project management, technical analysis, management consulting and decision-making experience in the electric and gas utility industries. His specializations are in the areas of energy services, load forecasting, resource planning, and strategic marketing.

Mr. Marks has functioned as Applied Energy Group, Inc.'s (AEG's) Chief Operating Officer for the past fifteen years. AEG's employee complement over this period has ranged from 15 to as high as 40. Mr. Marks has provided overall project management for many of AEG's largest consulting contracts. During a two-year assignment (1991 through 1992) for the New York Power Authority (the largest public authority in the United States), Mr. Marks provided on-site management services for a fifty-person department and for vendors with over 100 dedicated personnel.

Mr. Marks has overseen the selection of over $100 Million in services and equipment on behalf of utilities including the New York Power Authority, Bermuda Electric Light Company, Ltd., El Paso Electric Company and Minnegasco. Additionally, on behalf of El Paso Electric Company, Mr. Marks helped negotiate long-term energy contracts for the Company's largest customers whose annual bills totaled over $50 Million. Most recently, Mr. Marks has designed and managed the implementation of the largest deployment in the world of a two-way communications based direct load control system for the Long Island Power Authority.

Mr. Marks has testified, developed strategies and cross examination, and supported other witnesses in utility regulatory cases, many of which focused on bringing new generating stations into rate base. Utilities for which Mr. Marks provided these services include Western Resources, Georgia Power, Arizona Public Service, Long Island Lighting Company, New York Power Authority, Con Edison of New York, Kansas City Power & Light, Texas Utilities and El Paso Electric Company.

Mr. Marks has authored articles and made presentations on emerging utility-related issues in various industry conferences

Mr. Marks has an M.A. in Applied Economics with advanced course work in reengineering, statistics, energy services, and computer science.

CURRENT POSITION

Since 1987, Mr. Marks has been an Officer and Senior Vice President of Applied Energy Group, Inc. (AEG), a management consulting firm that serves the needs of the utility industries primarily in the areas of energy services, strategic planning, diversification studies, forecasting, innovative rate designs, customer service, reengineering, and business plan development. Since 1986, he has functioned as AEG's Chief Operating Officer.

PROFESSIONAL BACKGROUND

Applied Energy Group, Inc.	1982 - Present
Stone & Webster Management Consultants, Inc.	1980 - 1981
American Electric Power Service Corporation	1979 - 1980

CONSULTING PROJECTS

DIVERSIFICATIONS, BUSINESS PLANS, & BUSINESS PLAN IMPLEMENTATION

Bermuda Electric Light Company, Ltd. (BELCO) – Beginning in December 1995, AEG was retained by BELCO Energy Services Company (BESCO) to implement ESCO services throughout the island of Bermuda. The strategy that BELCO Holdings decided to employ was to have AEG function as BESCO management and field staff from 1996 throughout 1997. Mr. Marks provided overall management and implementation services on behalf of BELCO. On-site services were provided for a two-year period of approximately one week per month. These services were directly linked to a business plan (developed by AEG) that was approved by the Board of Directors of BELCO.

Worked with senior management on opportunities for diversification and franchise protection, with emphasis on the formation of an Energy Service Company.

El Paso Electric Company (EPEC) – Directed the design and implementation of start-up strategies for a new utility ESCO (Energy Services Business Unit - ESBU) in 1997, including product/service identification, vendor negotiations, operational procedures and organizational restructuring. Particular emphasis was placed upon the institutional and governmental sectors. Designed and implemented a strategic ally program to provide technical and implementation resources for various ESCO services (e.g., lighting retrofits, HVAC designs and installation, backup generator installation, etc.). Developed a comprehensive third party financing program for the ESBU.

Hampton Strategies / R. J. Rudden Associates, Inc. – Formed Hampton Strategies in 1992 to expand AEG's markets into the gas utility business. Converted AEG's interest in Hampton Strategies in 1994 into an equity position in R. J. Rudden Associates, Inc., a well-established consulting firm with skill sets that enhance AEG's ability to serve its changing domestic and international client base.

New York Power Authority (NYPA) – Worked as a full-time staff member over a two year period (1991 - 1992) in a management role in NYPA's DSM group on a $100 million dollar program which included a turnkey lighting retrofit program for large commercial and institutional customers throughout New York State. Responsibilities included program design, customer interface and supervision of all contractors. This program was and continues to be one of the largest DSM programs offered by a public authority in the United States.

Oglethorpe Power Corporation (OPC) – Prepared a Business Plan for EnerVision, a for-profit Company that OPC intended to create to separate the marketing functions from OPC. This plan described how EnerVision could successfully start-up and transition from the current marketing and economic development services at OPC.

Western Resources – Provided expert advisory services and research to assist in the development of a non-traditional Energy Service Company. A significant contribution was made by AEG to the business plan that was developed for this venture.

KEY CUSTOMER RETENTION

El Paso Electric Company (EPEC) – In 1998, developed and currently project manager for a business unit dedicated to key customer retention. The goal of this business unit is to develop innovative long-term rate contracts for many of EPE's key customers. Designed time-of-use rate design, indexing, marginal cost pricing, load factor targeting and other rate strategies. Continue to negotiate and develop long term contracts directly with key customers on EPE's behalf.

ENERGY SERVICES & DEMAND-SIDE MANAGEMENT (Selected Projects)

Atlanta Gas Light Company (AGLC) – Responsible officer and project manager for a multi-year (1993-1996) $700,000 DSM evaluation project. Responsibilities included preparation of evaluation plans, evaluating seven programs and interacting with and advising senior management.

Bermuda Electric Light Company, Ltd. (BELCO) – Designed and evaluated three pilot DSM programs that were implemented during 1993. The programs included a C&I Cooperative, a medium commercial audit and a residential direct install. This project was the first of its kind in the Caribbean.

Consolidated Edison Company of New York, Inc. – In April of 2001, AEG was retained by Con Edison of New York to project manage a residential load management pilot program using the Carrier system as well as the Comverge DCU technology. A goal of 500 systems was set, but only 200 were actually installed to the late start of the pilot. Con Edison approved a full scale program starting in May 2002 and Mr. Marks is currently the project manager responsible for all aspects of the program implementation for this residential Carrier thermostat based central air conditioning direct load control program. To date, over 1,000 customers have had Carrier systems installed in their homes with a goal of 10,000. Mr. Marks will also be responsible for the evaluation of this program.

Detroit Edison Company – Responsible officer and project manager for a process and impact evaluation of all 1994 and 1995 residential and low income DSM programs. The contract was administered through the Evaluation Collaborative (EC). The project involved research with trade allies, utility staff, implementation contractors, vendors, and participating and non-participating customers.

Iowa Power Company – Evaluated Iowa Power's first DSM program, a residential central A/C rebate program.

Long Island Power Authority – In the summer of 2000, authored a study on direct load control options for residential and small commercial customers. After presenting results to senior management, LIPA approved a $15 million program over an 18-month period. They selected a two-way communication based technology, which had only been piloted in very small numbers at a couple of utilities. Mr. Marks was given the responsibility to project manage all aspects of the program implementation. To date, over 16,000 customers (with a goal of 20,000) have had systems installed in their homes, making this the largest deployment of this type of technology in the world.

Long Island Lighting Company (LILCO) – Managed a comprehensive study of the persistence of equipment installed as a result of LILCO's C&I rebate and audit programs. This was one of the largest and most comprehensive studies on persistence ever conducted in the United States.

Served on a task force with LILCO management to develop state-of-the-art program tracking procedures and DSM program designs. Was the only non-LILCO employee on the task force.

Had overall responsibility for the evaluation of LILCO's 1987-1991 DSM programs. Over these years, LILCO had one of the most comprehensive DSM programs in the country with system coincident peak reductions of over 120 MW and annual expenditures of over $35 million. This project contributed to the generic DSM evaluation guidelines established by the NYPSC. Made presentations to the NYPSC during various stages of each evaluation.

Minnegasco – Conducted a competitive solicitation for implementation services related to three projects: C&I Multifamily Audit, Residential Home Energy Audit, and the Low-Income Weatherization Project for 1999. The scope of work included fully developing the RFP document for each project.

Provided contractor procurement services. Conducted a competitive solicitation for implementation services related to the Low-Income Weatherization Project for 1998.

Provided overall support and acted as an on-site technical advisor over the 1992-1994 period to develop a comprehensive DSM Plan. Responsibilities included all up-front planning, development of RFPs for multiple R&D projects with an over two million dollar budget, managed R&D projects, technical support on all activities, and the development of the comprehensive DSM Plan filing in July of 1994.

New Jersey Gas Utilities – Key witness of AEG team supporting three gas utility clients (New Jersey Natural Gas Company, Elizabethtown Gas Company and South Jersey Gas Co.) in 1999 state-wide proceedings before the NJ Board of Public Utilities on "Comprehensive Resource Analysis of Energy Programs" (Docket Nos. EX99050347, GO99050353, GO99050354, and GO99050352). Developed pre-filed direct testimony, program plan filing, rebuttal testimony, response to interrogatories and support during and after hearings (cross examination, surrebuttal, briefs). Proceeding addressed four-year plans (2000-2004) by all New Jersey Utilities for renewable and energy efficiency programs.

New York State Electric and Gas Corporation (NYSEG) – Had overall responsibility for a multi-million dollar impact evaluation of NYSEG's C/M/I DSM programs for the 1991 and 1992 calendar year.

Rochester Gas & Electric Corporation (RG&E) – Prepared RG&E's 1991-1993 compliance filings which were filed with the NYPSC to recover lost revenues and claim incentives for DSM activities.

Responsible Officer for the evaluation of RG&E's 1990-1993 DSM programs. Provided a comprehensive report filed with the NYPSC. Presentations were made to the NYPSC during various stages of each evaluation.

Western Kentucky Gas – Responsible Officer for the designing of 1997 WKG CARES Program and the evaluation of the 1997 Process and Impact Programs for this low Income Program. Presentations were made to the Western Kentucky Gas Collaborative and the CAP Agencies supporting the WKG program detailing the report findings.

INNOVATIVE MARKET SEGMENTATION & PROFITABILITY STUDIES

CINergy - Was selected in 1995 for a multi-phase project that had as its objective the meaningful (from a risk-profit perspective) segmentation of CINergy's key non-residential customer markets and the analysis of profitability of the segments. This was followed by the development of strategies to optimize the use of CINergy's marketing resources to maximize shareholder returns while ensuring the long-term viability of the company.

MARKET ASSESSMENT

Bermuda Electric Light Company, Ltd. (BELCO) – Developed an assessment of the potential for DSM including on-site interviews with most of the Island's largest customers.

Conducted an assessment of the potential revenue by specific product & service for a BELCO owned ESCO.

Electrical Generating Authority of Thailand (EGAT) – Was the responsible officer and project manager for this project funded by the World Bank to estimate the potential for DSM in the industrial sector in the country of Thailand. As part of this project, AEG retained in-country subcontractors to conducts audits and market research for primary data collection.

Western Resources – Conducted a market assessment of the potential revenue and earnings from 11 different ESCO products and services.

MARKET TRANSFORMATION

Consolidated Edison Company of New York, Inc. – Managed a market transformation study which attempted to measure the direct and in-direct impacts of information and free drivers during the 1990 - 1994 period. Study reviewed all programs and customer classes.

Long Island Lighting Company (LILCO) – Participated in a study to "right size" DSM for LILCO. Project involved a review of the current market and how LILCO's DSM programs, along with other factors may have "moved the market". The study included a repackaging of LILCO's program to more effectively spend DSM resources.

PLANNING & FORECASTING (Selected Projects)

Aquila — Responsible for the development of Aquila's 2003/2004 Conservation Improvement Program (CIP) filings for both People's Natural Gas and Northern Minnesota Utilities. Project tasks included program development and benefit-cost analyses. Responsibilities included coordination with utility and a presentation before public utility regulatory staff.

Berkshire Gas – Developed an econometric sales forecast by rate class. Also provide design day, design year and cold snap analysis.

Connecticut Natural Gas – Developed three separate econometric sales forecasts by rate class over a six year period including the development of econometric annual gas sales, cold snap, peak day and customer forecasts by class for resource planning and rate cases.

El Paso Electric Company (EPEC) – Developed econometric load forecasts for ten residential classes of service. Separate models were developed for customers and use per customer by service class. Prepared revised forecasting methodology document to be used in Company planning for regulatory proceedings. Developed a number of adjustment factors to normalize monthly energy sales by rate class for billing cycle, number of customers, weather and customer growth. These adjustment factors were used to improve the sales data that were used in the Company's forecasting models, which AEG had previously developed.

Freeport Electric – Provided analysis to determine the impact of the New York ISO on the utilities current and future costs for energy. Did extensive analysis on various resource options and future pricing given the uncertain environment caused by the recent activation of the ISO.

Developed an econometric electric sales and peak demand forecast by customer class. This was a resource planning and rate case.

Kansas City Power and Light Company (KCP&L) – Developed and implemented a residential econometric end use analysis. This analysis was the basis for Rebuttal Testimony filed on behalf of KCP&L.

Kansas Gas and Electric Company (KG&E) – Developed and implemented econometric end use load forecasts for the residential and commercial classes for use in the Company's long term planning process.

Iowa Power Company – Prepared a peak demand forecast and peak weather normalization for Iowa Power Company. This project included two separate analyses utilizing econometric models to normalize ten years of annual peaks and to forecast system peak over a ten-year period.

Minnegasco – Performed short-term sales load forecast using Box Jenkins Time Series Analysis. Models were developed by rate group for customers and use per customers. Forecast was used as part of direct testimony filed on behalf of Minnegasco.

Wellesley Municipal Light Plant - Developed an econometric electric sales and peak demand forecast by customer class. This was a resource planning and rate case.

The Village of Rockville Centre – Developed and implemented the 1997 Power Supply Planning Study for the Village of Rockville Centre which depicted a forecast analysis for a 15-year period. This study included a scenario in which a new customer with a 3.4 to 4.2 MW load was added to the system. The Village had identified such a customer, although their identity was kept confidential for this study. Updated the study in 2003 as part of a rate case filing. Will provide expert testimony on this analysis as well as other topics such as the impact of the New York ISO on the utility's future costs for power.

Saudi Arabia – In 1995, selected from an international list of experts to perform a comprehensive review of Saudi Arabia's largest utility's overall planning and forecasting procedures, methodologies, and results. This two-phase project called for the reengineering of these processes once the analytical and fact-finding phase was completed.

Southern Connecticut Gas – Developed a separate econometric sales forecast by rate class.

South Carolina Pipeline Corporation – Performed a five-year forecast for SCPC by class and customer type as part of an IRP filing. This forecast was the first ever performed for this intra-state gas pipeline, which serves 17 LDCs and directly serves hundreds of industrial customers.

UtiliCorp United – Responsible for the development of UtiliCorp's 1999/2000 and 2001/2002 Conservation Improvement Program (CIP) filings for both People's Natural Gas and Northern Minnesota Utilities. Project tasks included program development and benefit-cost analyses. Responsibilities included coordination with utility and a presentation before public utility regulatory staff.

Vanceburg Electric Light Heat and Power System – Performed a twenty-year Energy and Peak Load Forecast in connection with the proposed Hydro-Electric Dam on the Ohio River.

Vermont Gas – Performed ten-year sales forecast using Box Jenkins Time Series Analysis and multiple regression analysis. Models were developed by rate group for customers and use per customers. Estimates were provided for base and heat loads. High/low scenarios were developed as well. Forecast was used as part of an IRP filing.

Western Resources – Provided all statistical analysis to weather normalize test year sales as part of an overall rate case filing. Analysis was used as part of direct and rebuttal testimony.

STRATEGIC MARKETING & MARKET POTENTIAL ASSESSMENTS

New York Power Authority (NYPA) – Was retained in late 1994 by NYPA to conduct a customer satisfaction and needs study, the first ever conducted by NYPA. Results of this assignment will be used to develop new programs and economic development initiatives.

Day and Zimmermann, Inc. – Responsible for the preparation of a report for Day and Zimmermann, Inc. on the market potential for cogeneration technologies. This report included technical information, a marketing strategy, and review of all current forecasts for cogeneration.

Kansas Gas & Electric Company – Performed a market potential analysis. The study assessed the utility cost/benefits in relation to current and new customers using cogeneration with sensitivities on fuel type and rate design.

NYNEX Corporation – Assisted in the evaluation of the market potential for Automatic Meter Reading Systems, including preliminary cost/benefit evaluations.

Orange & Rockland Utilities – Responsible for a market potential analysis. The study assessed the utility cost/benefits in relation to current and new customers using cogeneration with sensitivities on fuel type and rate design.

EXPERT TESTIMONY & REGULATORY SUPPORT ASSIGNMENTS

Berkshire State Gas Company – Provided testimony to the Massachusetts Department of Telecommunications & Energy on behalf of the Berkshire State Gas Company Case No. D.T.E. 02-17. Testimony was in support of the Company's load forecast and supply plan of which I developed the load forecast.

Connecticut Natural Gas Corporation Docket No. 99-09-03 – Was a member of a panel, which testified before the Department of Public Utility Control in a year 2000 rate case. Mr. Marks was specifically responsible for all issues related to an econometric forecast that he prepared in support of the rate case.

Kansas City Power and Light Company / Kansas Docket #84-KG&E-197-R-142, O98-U / Missouri Docket #ER-85-128, EO-85-185 – Provided rebuttal testimony in the Wolf Creek Nuclear Plant rate case regarding forecasting related issues on behalf of KCP&L in both Kansas and Missouri.

South Carolina Pipeline – Prepared direct testimony before the South Carolina Public Service Commission on behalf of the South Carolina Pipeline Corporation Docket No. 94-202-G. Testimony was in support of the Company's first load forecast and supply plan of which I developed the load forecast.

El Paso Electric Company – Testified on behalf of El Paso Electric Company on the issues of load forecasting in Case No. 7460.

Arthur Kill, Prattsville, Indian Point – Assisted in the preparation of direct testimony, rebuttal testimony, and cross-examination in the Prattsville Pump Storage Project licensing procedure for NYPA, Case No.'s 50-247-SP, and 50-286-SP, Arthur Kill licensing proceeding for NYPA, Indian Point 3 Nuclear Power Plant Shutdown proceeding for the NYPA and the Indian Point 2 Nuclear Power Plant Shutdown proceeding for Con Edison.

Texas Utilities – Provided consulting services to Texas Utilities during the Comanche Peak Unit 1 and Unit 2 Rate Cases on the issues of need to build and prudence. Assisted in the preparation of testimony on the issue of nuclear performance standards. Managed the effort and wrote a comprehensive report entitled "The Lignite Utilization Report". This report covered TU's history regarding the use of lignite as a generating fuel, including exploration, acquisition criteria, recovery and generation.

Provided assistance in Unit 2 rate case including review of intervener testimony regarding performance standards. Provided analysis used in Company testimony regarding the bias of the performance standards testimony being recommended by the intervener.

Empire District Electric Company – Assisted in the preparation of testimony on the issue of weather normalization of energy sales in Case No. ER-90-138.

KeySpan – Performed statistical analysis in support of testimony before FERC on projections for fixed and variable O&M for KeySpan's generating plants.

New Jersey Gas Utilities – Provided direct and rebuttal testimony and cross-examination in a joint filing for three natural gas utilities (New Jersey Natural Gas Company, Elizabethtown Gas Company and South Jersey Gas Co.) in 1999 state-wide proceeding before the NJ Board of Public Utilities on "Comprehensive Resource Analysis of Energy Programs" (Docket Nos. EX99050347, GO99050353, GO99050354, and GO99050352).

Missouri Public Service – Assisted in the preparation of testimony of the issue of weather normalization of energy sales in Case No. ER-90-101.

Palo Verde Units 1 and 2 – Assisted in the preparation of rebuttal testimony and cross-examination on the subject of comparative economics of generation alternatives in the Palo Verde Unit 1 and Unit 2 Rate Case, No.'s U- 1345-85-156, and U-1345-85-367, before the Arizona Corporation Commission on behalf of Arizona Public Service Company, and before the Public Utility Commission of Texas on behalf of El Paso Electric Company for the Unit 2 Rate Case. Testimony concentrated on Nuclear O&M, Capacity Factor, and Capital Additions.

Assisted in the preparation of testimony on Nuclear performance standards on behalf of El Paso Electric in Case No.'s 8892, 9069, and 9165.

Shoreham – Prepared cross-examination for the Long Island Lighting Company in the Shoreham Nuclear Power Plant Abandonment proceeding before the New York Public Service Commission in Case No. 28252.

Wolf Creek / Kansas Gas and Electric Company / Kansas City Power and Light Company / Kansas Docket #84-KG&E-197-R-142, O98-U / Missouri Docket #ER-85-128, EO-85-185 – Assisted in the development of rebuttal testimony on lifecycle economics of nuclear vs. coal alternative. Provided first-year and lifecycle estimates of Wolf Creek's Operation and Maintenance Costs and Capital Additions Costs. Provided first-year and lifecycle estimates of Wolf Creek's Capacity Factors. Participated in the preparation of KG&E witnesses on the subjects of statistics, econometrics, forecasting, and engineering economics.

Commonwealth Of Kentucky - Case No. 99-070 – Western Kentucky Gas Company - Provided expert testimony on behalf of Western Kentucky Gas as past of a rate case. Testimony focused on past and future cost recovery for a low income DSM program.

EDUCATION

State University of New York at Binghamton, M.A., Applied Economics, 1979.
State University College of New York at Oswego, B.S., Mathematical Economics, 1977.
Areas of study include mathematics, economics, statistics, econometrics, computer science, matrix theory, and linear programming.

Academic Honors

Fellowship, SUNY Binghamton

Advanced Education

"Certificate of Mastery" in Reengineering from the Hammer Institute's Center for Reengineering Leadership.

Seminar in Box-Jenkins Time Series Analysis equivalent to the one-semester graduate level course. Seminar included the methodology and applications of Univariate Stochastic Models, Transfer Function Models, Multivariate Stochastic Models, Multivariate Transfer Function Models, and Intervention Analysis.

Seminar on Lighting Design (Efficient Lighting Solutions) - 1990.

Market training seminar for the New York ISO

AFFILIATIONS

ASHRAE
The Association of Energy Engineers
Association of Energy Services Professionals (AESP)

SELECTED ARTICLES & PUBLICATIONS

"LIPA Air Conditioning Direct Load Control Program" – presentation at NYSERDA's Price-Responsive Load Management conference in March, 2001.

Co-Authored, "Market Transformation - Can It Be Measured"; presented at the AESP Annual Conference; Phoenix, Arizona; December 5, 1995.

Co-Authored, "Comprehensive DSM Planning: A Gas Utility's Experience"; presented at the ADSMP "Demand-Side Marketing: The Competitive Face of DSM" Conference; Orlando, Florida; December 5-7, 1994.

"Where Do We Go, Based Upon What We Know?"; NYPA's Demand Side Management Customer Conference; April 22-23, 1993.

Co-Authored with Joseph T. Stanish, "DSM Bidding: A Formula for Success"; presented at the 6th National DSM Conference; Miami, Florida; March 1993.

"Implementing DSM for Public Sector Customers NYPA's High Efficiency Lighting Program"; Implementation of Demand-Side Management; June 23-24, 1992.

"DSM Evaluation The Role of Load Research"; AEIC Load Research Conference; September 12-14, 1990.

"Is There a Place for Microcomputers in Electric Utilities"; Public Utilities Fortnightly; December 8, 1983.

"Impact of Weather on Power System Loads"; Proceedings of the American Power Conference; 1980.

Exhibit No. ______
(MM-2)

Exhibit No.____
(MM-2)

Integrated Resource Plan

Prepared for:
Village of Rockville Centre
Rockville Centre, NY

Prepared by:
Applied Energy Group, Inc.
Hauppauge, NY

June 17, 2003

Table of Contents

Executive Summary

This study presents an updated Integrated Resource Plan for the Village of Rockville Centre. The purpose of this study is to provide information to the Village to assist in decision making regarding power supply, demand-side and distribution system planning over the next 15-years.

The elements of this study include energy and capacity forecasts, a review of potential supply-side options, and discussions of both transmission and distribution and conservation and load management issues.

The study's highlight's in each of these areas are as a follows:

1. Growth in summer peak demand is expected to grow to just under 54mW by the year 2017. This represents a compound annual growth rate in summer peak load of 0 .86%. Residential electricity usage is forecasted to grow at a rate of 0.83% and commercial kWh sales are forecasted to grow at a rate of 0.92%.
2. The Village of Rockville Centre currently provides power from the following resources:

    - A hydroelectric power allocation up to 29 MW, with grand fathered transmission rights to move the power from upstate New York to Long Island
    - A power plant located in the Village of Rockville Centre consisting of eight generating units with a total nameplate capacity of 33.6 MW [1]
    - Installed capacity credits (ICAP) purchased from KeySpan Energy in order to meet New York Independent System Operator (NYISO) requirements for on-island generating resources

    Units 7 and 8 are nearing the end of their operating life. Typically, low-speed diesel units of this type can be expected to operate up to approximately 200,000 hours with reasonable maintenance. Both units are approaching this limit, although they run for only a few hours per year. An economic evaluation was performed to examine the costs of several retirement and replacement options. In addition, potential renewable energy supply options were reviewed.

3. Transmission and distribution system limitations were also reviewed in light of the requirement to add additional capacity in the future. Given the backdrop of existing system limitations and the goal of providing a reliable and cost-effective system, there are 2 primary options available for reinforcement:

[1] The total credited towards NYISO installed capacity requirements is 31.0 MW due to the somewhat reduced capabilities of the older units.

Option 1. RVC-Ocean Avenue 3rd Supply Option – add a 3rd 33kV connection between the Ocean Avenue Substation and RVC's Maple Avenue Substation.

Option 2. New RVC Tap Option – add a 3rd 33kV connection to LIPA by intersecting the 33kV transmission line between the Bellmore and Ocean Avenue Substations.

4. In reviewing DSM options for Rockville Centre the degree to which implementation of proven techniques of conservation and load management might impact the projected need for additional capacity requirements must be explored. Over the next 20 years, peak load is expected to grow to between 51Mw and 55 Mw. Based on previous tasks, additional capacity or purchases of power to meet both customer needs and ICAP requirements is needed.

Rockville Centre is comprised primarily of residential and small commercial customers. In addition, the majority of opportunities for conservation would result from retrofitting existing customers' facilities which is both expensive and limited in the amount of savings which can be realized.

While certain programs (which are discussed in this report) can be beneficial both in terms of customer participation and cost, the potential impact that these programs can have on Rockville Centre's capacity requirements is not projected to be significant. Rockville's Centre's existing power supply has reached is limit to satisfy load growth and ICAP requirements.

I. Load and Energy Forecast

Demand forecasts estimate the amount of electricity needed in the geographic area served by a power system. Forecasts may project the amount of energy and demand that will be needed over the course of a day, a week, or a year.

In the context of integrated resource planning, forecasts typically look at energy and demand requirements from five to 30 years into the future. A demand forecast is basic to analyzing how much new generation capacity may be needed, which generation resources are applicable, how transmission and distribution systems should be expanded, and in which customer groups or geographic areas these requirements will be concentrated.

1. Data Needs for Demand Forecasting

Demand forecasts require data describing how electricity and alternative fuels are currently used in the utility system's service area. Some of the types of information needed for forecasting are:

- Sales records: Records of electricity sales for as many historical years as are available.
- Demand records: Data on power demand that chart the MW requirements on the utility over days, weeks, months, and years are needed to determine the relationship between electricity sales and the amount of generation capacity required. Disaggregated data are useful. The shape of the load curve (the variation of peak loads over time, or the load profile) helps to determine what types of generating capacity are needed.
- Economic and demographic data: Forecasting uses historical data on economic performance, and population or the number of households.
- Economic and demographic projections: A utility company may make its own economic and demographic projections for its service territory, or these projections may be obtained from an economic planning ministry or from some other entity.
- Energy end-use data: Types of end-use data include the number/fraction of households using specific electric appliances, the number/fraction of commercial, institutional, or industrial consumers using different types of electric equipment, and the amount of electricity used per customer per end use. These data are referred to as penetration or saturation data (for example, the percentage of households with electric space heating or cooking) and energy intensity data (for example, the kWh of electricity used per household per year). Ideally, historical data of these types would be available for each customer class and each major end use. In practice, even a single year's worth of such data may be hard to obtain. In some cases, partial data on appliance ownership or use, most frequently for the household sector, can be found in national census documents. In some developing

countries, government agencies or non-governmental organizations have studied energy end-use, or have been participated in data collection activities funded by bilateral or multilateral aid. These studies are rarely as complete as needed. New end-use surveys are often needed to obtain the data required for end-use forecasts.

2. *Types of Forecasting Models*

Methods used to forecast demand include trending, econometric analysis, end-use simulation, and combinations thereof.

Trend forecasting assumes that past rates of change in electricity use, or in electricity use per customer, will continue into the future. A growth rate calculated from historical data (sales or peak demand data) may be applied to estimate future consumption and demand. Separate trending forecasts can be compiled for each customer class or geographic division. Trending requires only access to basic sales and peak statistics, and the use of simple statistical methods. Trending forecasts assume that the future will be like the past, which often turns out to be untrue. Changes in technology, structural shifts in the economy or in demography, and changes in regulations are difficult to capture with a trending forecast. Trending is most useful for short-term forecasting (one to two years), for which the assumption that the future will be like the past is more robust.

Econometric forecasting assumes that past relationships between electricity use or peak demand and various economic or demographic variables continue to hold into the future, but econometric forecasts are generally more detailed than trending forecasts. In econometrics, the first step is to look for statistically significant historical relationships between economic variables and electricity sales or peak demand. Variables used to develop econometric relationships may include household income, electricity prices (by consumer group), prices for other household necessities, employment (by sector and sub-sector), labor productivity, tourism, industrial or agricultural output (measured in physical quantities or monetary terms), commercial-sector output (by sub-sector), use of other fuels, and the prices of other fuels.

Different statistical procedures can be used to test how well changes in one or more driving variables (such as those above) predict the value of the quantity to be forecast. In addition to testing the statistical significance of these relationships, econometric tools allow calculation of the mathematical relationships among parameters. Once statistically significant historical relationships between economic or demographic variables that affect electricity use or demand are identified and specified, projections for the driving variables must be developed. Such projections can often be obtained from ministries of economics or finance, or sources such as national banks. These projections are used to drive the econometric forecasts of electricity use or peak demand. As the factors that influence household electricity use are generally different from those that affect commercial, institutional, or industrial electricity needs, econometric forecasts, at least of electric energy use (as opposed to peak demand), are typically done separately for each major customer group, then aggregated to estimate system-wide sales.

The sales forecast incorporate two new major load additions that are added outside of the results of the econometric models. The first addition is a residential apartment complex that is expected to have a load of 1 MW. Since this is a residential complex, a load factor of 30% was assumed for the calculations of annual kWh sales. The apartment complex is expected to be 50% occupied in 2005 and fully occupied in 2006. The second addition was for a major expansion to the hospital. This load is estimated at 1.2 MW with a load factor of 80%. The hospital addition is expected to be 50% operational in 2006 and fully operational in 2007. The table below contains the year-by-year sales projections for these two additions.

Projected Electric Sales (MWH)
New Major Additions

	Residential Apartments	Commercial Hospital
2003	0	0
2004	0	0
2005	1,314	0
2006	2,628	4,205
2007	2,669	8,410
2008	2,719	8,431
2009	2,756	8,449
2010	2,766	8,472
2011	2,762	8,505
2012	2,757	8,538
2013	2,751	8,571
2014	2,746	8,604
2015	2,741	8,638
2016	2,737	8,672
2017	2,731	8,705

The sales forecast is shown in Table I-1 below. (Note that all forecast results shown in the following pages do not include line losses which have been estimated at 4.3 %.)

Table I-1: Projected Electric Sales (MWH)

Forecast	Residential	Commercial	Mun/StLgt/PA	Total Sales
2003	88,408	98,271	5,725	192,404
2004	90,606	98,782	5,736	195,124
2005	92,997	99,142	5,748	197,887
2006	95,463	103,558	5,759	204,780
2007	96,958	107,958	5,766	210,681
2008	98,780	108,233	5,777	212,790
2009	100,121	108,466	5,802	214,389
2010	100,484	108,762	5,826	215,071
2011	100,330	109,184	5,840	215,354
2012	100,139	109,607	5,855	215,601
2013	99,942	110,032	5,870	215,844
2014	99,748	110,459	5,885	216,093
2015	99,552	110,889	5,901	216,342
2016	99,407	111,321	5,916	216,643
2017	99,211	111,755	5,931	216,897

Residential kWh sales are forecasted to grow at a rate of 0.83%, compared to an historical growth rate of 1.15% (note: not normalized for weather) during the 1993 through 2001 historical period. While forecasted growth is expected to be lower than historical growth, the forecast is based on "normal weather". Taking this into account, there is no statistically significant difference between historical and forecasted growth rates. Commercial kWh's sales are forecasted to grow at a rate of 0.92%, compared to an historical growth rate of 1.06% during the 1993 through 2001 historical period. Other sales, which include Municipal, Street Lighting, Water and Public Authority, are forecasted to grow at a rate of 0.25%. This compares to an historical growth rate of 0.89% during the 1993 through 2001 historical period. Total system sales are forecasted to grow at a rate of 0.86%, compared to the historical growth rate during the 1993 through 2001 period of 1.09%.

The summer peak demand forecast is shown in Table I-2 below.

Table I-2: Summer Peak Demand Forecast (MW)

Year	Summer Peak Demand	Growth Rate	Load Factor
2003	47.17	-3.46%	46.56%
2004	48.00	1.76%	46.56%
2005	50.04	4.25%	46.56%
2006	51.24	2.41%	46.56%
2007	51.66	0.82%	46.56%
2008	52.18	1.00%	46.56%
2009	52.57	0.75%	46.56%
2010	52.74	0.32%	46.56%
2011	52.81	0.13%	46.56%
2012	52.87	0.11%	46.56%
2013	52.93	0.11%	46.56%
2014	52.99	0.12%	46.56%
2015	53.05	0.12%	46.56%
2016	53.12	0.25%	46.56%
2017	53.19	0.26%	46.56%

The forecasted compound growth rate from 2003 through 2017 is 0.86%. This is lower than the historical peak growth rate of 1.69% over the 1997 to 2002 period but closer to the 1.17% growth rate from 1998 to 2002.

The Winter Peak Demand forecast is shown in the Table I-3 below.

Table I-3: Winter Peak Demand Forecast (MW)

Year	Winter Peak Demand	Growth Rate	Load Factor
2002/03	32.65	1.26%	67.28%
2003/04	33.22	1.76%	67.28%
2004/05	34.63	4.25%	67.28%
2005/06	35.47	2.41%	67.28%
2006/07	35.76	0.82%	67.28%
2007/08	36.12	1.00%	67.28%
2008/09	36.39	0.75%	67.28%
2009/10	36.50	0.32%	67.28%
2010/11	36.55	0.13%	67.28%
2011/12	36.59	0.11%	67.28%
2012/13	36.63	0.11%	67.28%
2013/14	36.68	0.12%	67.28%
2014/15	36.72	0.12%	67.28%
2015/16	36.77	0.25%	67.28%
2016/17	36.81	0.26%	67.28%

The forecasted compound growth rate from 2002/03 through 2016/17 is 0.86%.

AEG has developed sensitivity analyses to reflect conditions that could result in both higher and lower estimates of peak demand. Sensitivities are important because they provide a bandwidth around the Most Likely peak forecast which is intended to assist the utility planner in understanding the width of the planning window in any given year. With knowledge of this bandwidth, investments in utility plant can be more efficiently timed and scaled to minimize the present value of the revenue requirement necessary to effectively run the utility.

The peak demand sensitivity runs were as follows:

System Peak Demand High Case - This scenario used the Most Likely load factor in 2002 and reduced it by one tenth of a percent per year. This reflects uncertainty in the most likely load factor assumption in the direction that would result in a higher peak demand forecast.

System Peak Demand Low Case - This scenario used the Most Likely load factor in 2002 and increased it by one tenth of one percent per year. This reflects uncertainty in the most likely load factor assumption in the direction that would result in a lower peak demand forecast.

Table I-4 contains the High and Low Case peak demand forecasts respectively.

Table I-4: Summer High/Low Case Peak Demand Forecast (MW)

Year	Summer High Case Peak Demand	High Case Growth Rate	High Case Load Factor	Summer Low Case Peak Demand	Low Case Growth Rate	Low Case Load Factor
2003	47.17		46.56%	47.17		46.56%
2004	48.10	1.97%	46.46%	47.89	1.54%	46.66%
2005	50.25	4.48%	46.36%	49.82	4.03%	46.76%
2006	51.57	2.63%	46.26%	50.91	2.19%	46.86%
2007	52.11	1.04%	46.16%	51.22	0.61%	46.96%
2008	52.75	1.22%	46.06%	51.63	0.79%	47.06%
2009	53.26	0.97%	45.96%	51.90	0.54%	47.16%
2010	53.54	0.54%	45.86%	51.96	0.11%	47.26%
2011	53.73	0.35%	45.76%	51.92	-0.08%	47.36%
2012	53.91	0.33%	45.66%	51.87	-0.10%	47.46%
2013	54.09	0.33%	45.56%	51.82	-0.10%	47.56%
2014	54.27	0.34%	45.46%	51.77	-0.09%	47.66%
2015	54.45	0.34%	45.36%	51.72	-0.09%	47.76%
2016	54.65	0.36%	45.26%	51.68	-0.07%	47.86%
2017	54.84	0.34%	45.16%	51.63	-0.09%	47.96%
Compound Growth Rate	1.08%			0.65%		

II. Supply Analysis

1. *Current Supply Resources*

The Village of Rockville Centre currently provides power from the following resources:

- A hydroelectric power allocation up to 29 MW, with grand fathered transmission rights to move the power from upstate New York to Long Island
- A power plant located in the Village of Rockville Centre consisting of eight generating units with a total nameplate capacity of 33.6 MW [2]
- Installed capacity credits (ICAP) purchased from KeySpan Energy in order to meet New York Independent System Operator (NYISO) requirements for on-island generating resources

Most of the energy supplied by the Village to its customers is provided by the hydroelectric power transported from upstate New York. This hydroelectric allocation varies with the availability of hydro generating resources and with the Village's load factor. As the load factor increases, a larger allocation is provided up to the 29 MW ceiling. The primary reasons the Village maintains its own power generation facilities are to meet its installed capacity requirements and provide increased reliability. It is important to note that the Village's current contract for hydropower expires in 2013.

The existing power plant on Maple Avenue therefore plays an important role in managing the Village's overall cost of electricity. This power plant was constructed over a number of years. Installed generating units are summarized in Table II-1.

Table II-1: Village of Rockville Centre Installed Generating Capacity

Unit #	Nameplate Capacity (kW)	Year of Initial Operation	Fuel	Manufacturer
14	6,300	1994	No. 2 Oil/Natural Gas	Cooper-Bessemer
13	5,500	1973	No. 2 Oil/Natural Gas	Nordberg
12	5,500	1967	No. 2 Oil/Natural Gas	Nordberg
11	5,200	1961	No. 2 Oil/Natural Gas	Nordberg
10	3,200	1954	No. 2 Oil/Natural Gas	Nordberg
9	3,200	1954	No. 2 Oil/Natural Gas	Nordberg
7	2,000	1942	No. 2 Oil	Nordberg
8	2,700	1950	No. 2 Oil	Nordberg
Total Nameplate Capacity	33,600			

[2] The total credited towards NYISO installed capacity requirements is 31.0 MW due to the somewhat reduced capabilities of the older units.

The dual-fueled units account for 28.9 MW. No. 2 fuel oil is used primarily as a pilot ignition fuel in these units, although they can also be operated at their full rating on fuel oil. The oldest units are capable only of firing No. 2 fuel oil. The plant has two restrictions governing operation on the two fuels. First, plant capacity on natural gas is limited to approximately 15 MW due to pipeline limitations. The power plant has an existing natural gas booster compressor used to maintain gas pressure at approximately 60 psig. However, there is insufficient pipeline capacity to operate all of the dual-fueled units on natural gas simultaneously. Second, the plant must meet two emissions requirements. Unit 14, the newest engine-generator, must meet specific permit limits for NO_x, CO, particulates and volatile organic compounds (VOC). This unit is equipped with catalysts for NO_x and CO emission control. In addition, it must not exceed 600 hours per year of operation on No. 2 fuel oil. For the remaining units, the plant must not exceed average NO_x emissions of 9 grams per brake horsepower-hour (BHP-hour).

New generating units would be permitted based on the applicable regulations in 6NYCRR Part 231-2 New Source Review in Non-Attainment and Ozone Transport Regions. The requirements for permitting new sources in severe non-attainment regions depend on the maximum potential to emit specific pollutants. In general, it appears that a new generating plant would be required to meet Lowest Achievable Emission Rates (LAER) for NO_x, CO and volatile organic compounds unless the maximum emission potential is below *de-minimis* levels. External offsets would also be required at a 1.3 to 1 ratio. In a severe ozone non-attainment area, the *de-minimis* thresholds are 40 tons per year for NO_x and 100 tons per year each for CO and VOC. LAER technology is not clearly defined. Instead, it is based on a survey of the lowest rates achieved by similar units in other parts of the country. Recent LAER thresholds in New Jersey indicate, for example, that spark-ignited, gas-fueled, internal combustion engines would have to meet the following standards:

NO_x:	0.70 grams per BHP-hour
CO:	0.50 grams per BHP-hour
VOC:	0.25 grams per BHP-hour

The regulations currently allow alternative to LAER and external offsets. The most recent data available shows that the plant-wide capacity factor is slightly above three percent. At this level of operation, new generating units would not approach the *de-minimis* emission limits. In this case, it may be possible to permit the units using a less restrictive standard than LAER in exchange for operating hour limits on the new and existing units.

In addition to the above requirements, New York has also proposed new regulations for a NO_x emissions trading system. At the time of this analysis, the regulations appear to exempt the Village's unit from mandatory participation in the trading system. Voluntary participation is allowed. Given the uncertainties regarding permitting, a more in-depth permitting analysis would be necessary to define acceptable strategies. For the purposes of this analysis, LAER technology has been included.

Other new regulations, although not published yet, may require significant changes to the existing generating facility. It is our understanding that the Village is studying these regulations. Modifications and/or replacements of the existing units as a result of these regulations is beyond the scope of this report.

III. Evaluation of Future Capacity Options

1. Background

Units 7 and 8 are nearing the end of their operating life. Typically, low-speed diesel units of this type can be expected to operate up to approximately 200,000 hours with reasonable maintenance. Both units are approaching this limit, although they run for only a few hours per year. An economic evaluation was performed to examine the costs of several retirement and replacement options.

An important factor in the evaluation and decision-making process is the NYISO's requirement for on-island generating capacity. To summarize, NYISO requires that load-serving entities on Long Island must install or purchase on-island generating capacity equivalent to a percentage of their annual peak load. The percentage changes over time, although it is currently set at 87.48 percent. For the Village of Rockville Centre, this is equivalent to 41.9 MW over the near term. The Village currently has a two-year contract with KeySpan Energy to supply it with ICAP requirements over its own generating resources at a rate of $7.50/kW-month, which does not reflect a credit from LIPA for the rest of State auction results. Long-term expectations are that the ICAP rate will decline as new generating resources are installed on Long Island.

From the preceding discussion, the Village of Rockville Centre must evaluate whether to buy ICAP credits or build its own generating capacity while considering the following factors:

- Installed generating capacity is important to the Village because it maintains reliability levels and helps to meet NYISO ICAP requirements.
- The two oldest units, accounting for 4.7 MW of capacity are near the end of their useful lives. Removing them from service will affect Village ICAP purchases.
- ICAP requirements will play a major role in ultimately determining how much capacity needs to be installed. Based on rules published by NYISO on December 30, 2002, load-serving entities receive credit for installed capacity based on Unforced Capacity (UCAP), which takes into account the forced outage rate of a capacity resource. New, low cost diesel units may qualify for only parts of the year if their operating hours or seasonal availability are restricted for environmental reasons. Seasonal restrictions could eliminate the use of diesels altogether during the summer.
- Natural gas is the preferred fuel since it is highly unlikely that the chief alternative (No. 2 fuel oil) will meet anticipated emissions constraints without operating hour or seasonal constraints.
- Natural gas capacity for the Village's power plant is limited and additional pipeline capacity will be needed if gas-fueled generation is added.

2. *Scenarios and Methodology*

Six different scenarios were analyzed and are summarized in Table III-1.

Table III-1: Scenario Summary

	Case	Description	Generation Equipment Configuration
Retirement Options	Unit 7 & 8 Retirement Base Case	Retire Units 7 & 8 and purchase all ICAP requirements	No replacement, but substation and transmission upgrades necessary
Retirement Options	Option 1	Retire Units 7 & 8; install two natural gas-fueled reciprocating engines to replace retired units; purchase ICAP deficit	Two 2,800 kW engine-generators replace Units 7 & 8
Retirement Options	Option 2	Retire Units 7 & 8; install a single natural gas-fueled combustion turbine to replace retired units; purchase ICAP deficit	One 4,700 kW combustion turbine replaces Units 7 & 8
Non-Retirement Options	Option 3	Allow Units 7 & 8 to remain in service indefinitely; install two natural gas-fueled reciprocating engines to meet ICAP requirements; sell any ICAP excess	Add two 5,700 kW engine-generators to meet ICAP requirements
Non-Retirement Options	Option 4	Allow Units 7 & 8 to remain in service indefinitely and install two natural gas-fueled combustion turbines to meet ICAP requirements; sell any ICAP excess	Add two 6,500 kW combustion turbines to meet ICAP requirements

The cases above are divided into two groups – retirement and non-retirement options. Retirement options assume that the Village will continue to purchase at least some of its ICAP requirements. Under these scenarios, new capacity replacement is nearly equal to the capacity retired.

Non-retirement options assume that Units 7 and 8 will remain in service indefinitely. Although the units are approaching the end of their useful lives, they are operated only a few hours per year, and can be credited towards ICAP requirements. Under these scenarios, the Village installs enough new capacity to meet all of its ICAP requirements with its own generation resources. Because available generating units do not precisely match expected ICAP requirements, excess capacity may be available for sale.

Comparison of the above options is based on a revenue requirement analysis. Input assumptions common to all cases are provided in Table III-2.

Table III-2: Common Input Assumptions

Input Item	
First Year Fuel Cost ($/MMBTU)	$6.00
Annual Fuel Price Escalation (%)	2.0%
Book Life (Years)	25
Discount Rate	4.0 and 6.0%
General Escalation for non-fuel O&M (%)	2.5%
Capacity Factor	0.03

A sensitivity analyses was done for the discount rate at 4.0 and 6.0 percent.

It is assumed that the Village would finance construction of any new generation using revenue bonds. Taxes are excluded from the analysis since the revenues collected by the Village for utility service are not taxed.

Capital cost assumptions for all of the equipment cases are provide in Table III-3. Equipment pricing was based on discussions and budgetary quotations from manufacturers for reciprocating engines and combustion turbines of the types and sizes likely to be considered for future generation projects.[3] The equipment manufacturers and models included in Table III-3 are intended to illustrate potential costs. They are not intended to limit any future bidding or selection processes.

Capital costs include gas compressors for both options where combustion turbines are considered. This is required because the gas pressure necessary for combustion turbines is substantially higher than that required for reciprocating engines. In all cases, a new natural gas pipeline is required, but is not included in the cost estimates for specific options. This was done because a pipeline capacity upgrade would serve all existing as well as future units and should be allocated only to new generating units. According to budgetary estimates provided by KeySpan Energy, the capital cost of providing upgraded gas capacity to the Village's power plant would be $3,970,000. This includes installation of a new 8-inch pipeline from KeySpan's 30-inch, 450-psig gas main at Hendrickson and South Park Street approximately 5,000 feet away from the plant. Minimum guaranteed pressure would be 170 psig at the Village's power plant, which is adequate for reciprocating engines. At least 300 psig is required for combustion turbines. KeySpan's cost estimate includes new metering and taxes.

Each option assumes that NO_x and CO catalysts will be necessary to meet environmental permitting requirements.

Capital costs estimates include an overall contingency factor of 20 percent due to the uncertainties of budgetary equipment costs estimates, construction costs and market conditions at the time of actual installation.

Non-fuel variable operating and maintenance costs are expected to differ between reciprocating engines and combustion turbines. A factor of 0.07 cents per kWh is used for combustion turbines, and a factor of 0.1 cents per kWh is used for reciprocating engines. Fixed O&M costs are based on the Village's average costs from 2001 and 2002. The largest component of fixed operating costs is labor. A factor of $40 per kW-year is

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[3] Manufacturers contacted included Wartsilla and Fairbanks-Morse for reciprocating engines and Solar Turbines for combustion turbines. Only Wartsilla's equipment is represented in the analysis for reciprocating engines for the sake of simplicity. Pricing, performance and sizing are similar for both manufacturers.

used for all generating plant options.[4] All O&M costs are escalated at 2.5 percent annually.

Capital costs of substation and transmission upgrades are evaluated separately and are not included in this section. However, it is important to note that if the Village chooses to retire Units 7 and 8 and purchase its ICAP requirements, then substation and transmission upgrades will be required.

[4] Fixed O&M costs were estimated using the Village of Rockville Centre's Annual Report to the New York Public Service Commission for the year ended May 31, 2001. Fixed O&M expenses were calculated using the sum of accounts 713 (Labor), 714.3 (Miscellaneous Supplies and Expenses), 715 (Repairs to Power Plant) and dividing by the total capacity. The figure was then rounded down to $40 per kW-year to reflect expected lower maintenance for new generating units.

Table III-3: Capital Cost Assumptions

CAPITAL COST ESTIMATE		Option 1	Option 2	Option 3	Option 4
Manufacturer		Wartsila	Solar Turbine	Wartsila	Solar Turbine
Model		18V220SG	Taurus 60	18V34	Taurus 70
Nominal Rating (kW)		2,800	5,500	5,700	7,520
Rating at 95oF (kW)		2,800	4,700	5,700	6,500
Average Net Heat Rate (BTU/kWh)		9,200	12,909	8,625	11,615
Budgetary Equipment Price		$ 1,700,000	$ 2,150,000	$ 3,400,000	$ 2,700,000
SCR Adder		$ 350,000	$ 400,000	$ 428,000	$ 500,000
CO Catalyst		$ 200,000	$ 200,000	$ 200,000	$ 250,000
CEMs		$ 200,000	$ 200,000	$ 200,000	$ 200,000
Gas Compressor		$ -	$ 350,000	$ -	$ 450,000
Subtotal Equipment (per unit)		**$ 2,450,000**	**$ 3,300,000**	**$ 4,228,000**	**$ 4,100,000**
Number of Units		**2**	**1**	**2**	**2**
Total Capacity (kW)		**5,600**	**4,700**	**11,400**	**13,000**
Total Equipment Cost		**$ 4,900,000**	**$ 3,300,000**	**$ 8,456,000**	**$ 8,200,000**
Total Equipment Cost ($/kW)		**$ 875**	**$ 702**	**$ 742**	**$ 631**
Mechanical & Electrical Installation Allowance ($/kW)		$ 125	$ 100	$ 125	$ 100
Mechanical & Electrical Installation		$ 700,000	$ 470,000	$ 1,425,000	$ 1,300,000
Engineering [5]		$ 200,000	$ 200,000	$ 200,000	$ 200,000
Construction Management (% of Equipment & Installation Costs)	3%	$ 168,000	$ 113,100	$ 296,430	$ 285,000
Subtotal Engineering & Installation		**$ 1,068,000**	**$ 783,100**	**$ 1,921,430**	**$ 1,785,000**
Total (Equipment, Engineering & Installation)		**$ 5,968,000**	**$ 4,083,100**	**$ 10,377,430**	**$ 9,985,000**
Project Contingency (% of Total)	20%	$ 1,193,600	$ 816,620	$ 2,075,486	$ 1,997,000
Total (Including contingency)		**$ 7,161,600**	**$ 4,899,720**	**$ 12,452,916**	**$ 11,982,000**
Installed Cost ($/kW)		**$ 1,279**	**$ 1,042**	**$ 1,092**	**$ 922**

[5] Engineering costs are not expected to vary significantly based on the equipment options. The equipment evaluated in this analysis is largely pre-packaged, requiring a minimum of site-specific engineering. In addition, identical units are used in multi-unit options, which minimizes the need for unit-specific design variations.

Each of the options described in Tables III-1 and III-3 result in different ICAP scenarios. ICAP surpluses or deficits are shown for each case in Table III-4:

Table III-4: ICAP Surpluses and Deficits

	Retirement Base Case	Option 1	Option 2	Option 3	Option 4
Current Installed Capacity (kW)	33,600	33,600	33,600	33,600	33,600
Planned Retirements	4,700	4,700	4,700	-	-
New Capacity	-	5,600	4,700	11,400	13,000
Expected ICAP Requirement	41,900	41,900	41,900	41,900	41,900
ICAP Deficit/Surplus	(13,000)	(7,400)	(8,300)	3,100	4,700

For deficits, it was assumed that ICAP requirements would be met by purchasing it at \$7.50/kW-month (\$90/kW-year). For surpluses, it was assumed that excess capacity could be sold at the same rate.

3. *Results*

Tables III-5 and III-6 provide summaries of the results of the revenue requirement analysis for each scenario at discount rates of 4 and 6 percent. The net present value of revenue requirements (NPVRR) is used to compare each case.

Each column represents one scenario. The total NPVRR consists of the total NPVRR for new generating capacity, new gas pipeline and ICAP costs or credits. A sensitivity analysis was performed for ICAP costs at \$7.50/kW-month and \$5.00/kW-month. In both cases, it was assumed that ICAP costs would escalate at 2.5 percent annually.

Regardless of discount rate, the lowest cost scenario is the Base Case Retirement option, which assumes that Units 7 and 8 will be retired. The analysis shows, in general, that it is less costly to continue purchasing ICAP credits rather than installing new generating capacity to meet ICAP requirements. This is because ICAP is relatively inexpensive compared to installing new capacity on a per kW basis. At \$7.50/kW-month, ICAP is equivalent to \$1,827/kW NPVRR at a 4% discount rate and \$1,461/kW NPVRR at a 6% discount rate. At \$5.00/kW-month, it is \$1,218/kW NPVRR at a 4% discount rate and \$974/kW NPVRR at a 6% discount rate. However, the capital costs of upgrading the substation and transmission systems in order to permit higher import levels is estimated to be approximately \$4.5 million (\$2.3 million for the substation and \$2.2 million for the transmission upgrade. This is equivalent to \$225/kW, which must be added to the Base Case Retirement Option. In comparison, the least costly generation option is \$2,067/kW at the 4% discount rate and \$1,828/kW NPVRR at the 6% discount rate, excluding the costs of the gas pipeline.

Table III-5: Summary of Analysis Results for Discount Rate at 4%

	Retirement Base Case	Option 1	Option 2	Option 3	Option 4
Calculated Capital Cost ($/net kW, excluding gas pipeline)		$ 1,279	$ 1,042	$ 1,092	$ 922
Total NPVRR New Generating Capacity ($/1000)		$ 13,123	$ 10,451	$ 24,442	$ 26,867
NPVRR/KW		$ 2,343	$ 2,224	$ 2,144	$ 2,067
First Year Fuel Cost (cents/kWh)		5.52	7.75	5.18	6.97
NPVRR Gas Pipeline Construction ($/1000)		$ 3,848	$ 3,848	$ 3,848	$ 3,848
Current Installed Capacity (kW)	33,600	33,600	33,600	33,600	33,600
Planned Retirements	4,700	4,700	4,700		
New Capacity		5,600	4,700	11,400	13,000
Expected ICAP Requirement	41,900	41,900	41,900	41,900	41,900
ICAP Deficit/Surplus	(13,000)	(7,400)	(8,300)	3,100	4,700
NPVRR ICAP Purchase/Credit @ $7.50/kW-month ($/1000)	$ 23,751	$ 13,520	$ 15,164	$ (5,664)	$ (8,587)
NPVRR ICAP Purchase/Credit @ $5.00/kW-month ($/1000)	$ 15,834	$ 9,013	$ 10,109	$ (3,776)	$ (5,725)
Total NPVRR including ICAP Purchase/Credit @ $7.50/kW-month and gas pipeline construction ($/1000)	$ 23,751	$ 30,513	$ 29,487	$ 22,649	$ 22,151
Total NPVRR including ICAP Purchase/Credit @ $5.00/kW-month and gas pipeline construction ($/1000)	$ 15,834	$ 26,007	$ 24,432	$ 24,537	$ 25,014

Table III-6: Summary of Analysis Results for Discount Rate at 6%

	Retirement Base Case	Option 1	Option 2	Option 3	Option 4
Calculated Capital Cost ($/net kW, excluding gas pipeline)		$ 1,279	$ 1,042	$ 1,092	$ 922
Total NPVRR New Generating Capacity ($/1000)		$ 11,856	$ 9,292	$ 21,914	$ 23,769
NPVRR/KW		$ 2,117	$ 1,977	$ 1,922	$ 1,828
First Year Fuel Cost (cents/kWh)		5.52	7.75	5.18	6.97
NPVRR Gas Pipeline Construction ($/1000)		$ 3,848	$ 3,848	$ 3,848	$ 3,848
Current Installed Capacity (kW)	33,600	33,600	33,600	33,600	33,600
Planned Retirements	4,700	4,700	4,700		
New Capacity		5,600	4,700	11,400	13,000
Expected ICAP Requirement	41,900	41,900	41,900	41,900	41,900
ICAP Deficit/Surplus	(13,000)	(7,400)	(8,300)	3,100	4,700
NPVRR ICAP Purchase/Credit @ $7.50/kW-month ($/1000)	$ 18,993	$ 10,811	$ 12,126	$ (4,529)	$ (6,867)
NPVRR ICAP Purchase/Credit @ $5.00/kW-month ($/1000)	$ 12,662	$ 7,208	$ 8,084	$ (3,019)	$ (4,578)
Total NPVRR including ICAP Purchase/Credit @ $7.50/kW-month and gas pipeline construction ($/1000)	$ 18,993	$ 26,515	$ 25,266	$ 21,233	$ 20,751
Total NPVRR including ICAP Purchase/Credit @ $5.00/kW-month and gas pipeline construction ($/1000)	$ 12,662	$ 22,911	$ 21,224	$ 22,743	$ 23,040

If generating capacity is installed, Tables III-5 and III-6 show that the assumed value of the ICAP costs or credits can affect the selection of the plant. If the assumed value of ICAP is low ($5.00/kW-month), then the differences between the generation options analyzed are fairly narrow – a difference of approximately 6.4% (at 4% discount rate) and 8.5% (at 6% discount rate) between highest cost (Option 2) and lowest cost (Option 4). For the higher ICAP value, the spread between highest and lowest cost generating options increases to nearly 38% (at 4% discount rate) and 28% (at 6% discount rate).

IV. Potential Renewable Energy Supply Options

Renewable energy options were also analyzed. Solar photovoltaic (PV) and wind are the resources primarily available on Long Island. Wind can also be purchased from suppliers outside of Long Island. PV is not suitable for bulk power production because of high capital costs and the need for very large plots of land. However, PV can be used as customer-sited supplemental generation, and the Village should evaluate on-going LIPA programs as models for its own residential and commercial users.

Wind resources must be purchased from third-party suppliers because the Village does not have the land area or available wind resource for wind power development. Wind purchases are available at a premium above market-based prices for electricity. Transmission rights must also be purchased to delivery the power to the Village. Based on these factors, the Village is not currently considering wind power purchases as part of its base resources. However, the Village should evaluate the use of green pricing to purchase wind power in the future for customers who are interested in supporting the development of renewable resources. The Village should also carefully follow the development of potential offshore wind projects which may provide wind power to Long Island at lower cost than off-island resources.

V. Rockville Centre Transmission and Distribution Issues

1. Existing System

The purpose of this section of the IRP is to analyze the impact of the RVC T&D system on the IRP and specifically investigate any limitations the current system places on internal generation or economic power purchase options as well as distribution planning. operating and reliability issues.

Currently, RVC is interconnected to the LIPA 33kV subtransmission system through 2-33kV cables (33-352 and 33-353) from LIPA's Ocean Avenue Substation to RVC'c Maple Avenue Substation (Figure 1). These cables have a rated normal capacity of 36 MVA each and are utilized to supply NYPA power to RVC. These cables are now the limiting factor or "weakest link" to the LIPA system and dictate maximum power flows in and out of RVC (especially under conventional contingency planning conditions with one cable out of service). Prior to last summer, RVC import capability was determined by transmission limitations on the LIPA 33kV system. However, RVC initiated the 33 kV reinforcements identified in the "LIPA/RVC Interconnection System Analysis Report" directed by AEG with the result that the LIPA 33kV system now has sufficient capacity to supply 100% of RVC's scheduled hydropower allocation through 2007[6]. It should also be noted that the 2 cables from the Ocean Avenue Substation occupy the same pole line for a portion of their route, therefore increasing the potential for a double contingency situation. If this contingency ever occurred during peak load conditions, it would have a significant impact on RVC and would likely result in load shedding as RVC cannot meet its customer's load requirements with internal generation alone. Additionally, damage to these cables could take an extended time period to repair, thus making public load drop appeals and rotating blackouts a real possibility.

The existing distribution system supply at RVC is comprised of 2-15MVA and 2-5MVA 33/4kV transformers totaling 40MVA of capacity (Figure 2). They essentially match current RVC load demand during summer peak, although during most of the summer RVC must run existing internal generation in order to meet the electrical requirements of it's customers. Further, RVC has several distribution feeders that "share" a distribution breaker, thus not only making distribution operations more complex but also decreasing overall reliability and extending outage times for contingencies. Thus, additional distribution transformer and feeder capacity is required and should be a part of an overall IRP plan.

[6] Pursuant to March 1, 2002 memo re: "NYPA's Proposed Schedule of Deliveries to Municipalities" from Mr. Joe Gredder (LIPA) to Mr. Jordan Brandeis (NYPA).

2. *Planning Options*

Given the backdrop of existing system limitations and the goal of providing a reliable and cost-effective system, there are 2 primary options available for reinforcement:

Option 1.	RVC-Ocean Avenue 3rd Supply Option – add a 3rd 33kV connection between the Ocean Avenue Substation and RVC's Maple Avenue Substation.
Option 2.	New RVC Tap Option – add a 3rd 33kV connection to LIPA by intersecting the 33kV transmission line between the Bellmore and Ocean Avenue Substations.

Option 1: RVC-Ocean Avenue 3rd Supply Option

This option is the more conventional reinforcement option and the one postulated by LIPA in their system reinforcement study for RVC. The 33kV line would be completely underground and would require 33kV line breakers at both substations. For reliability purposes, additional 33kV bus tie breakers should be installed at both Ocean Avenue and Maple Avenue, although it appears questionable that sufficient bus space is available to do so (Figure 3). This would result in decreasing the reliability normally associated with constructing an additional transmission tie.

While this option would increase supply capacity to RVC and maintain the existing lines of demarcation between LIPA and RVC, it would not significantly increase reliability under certain contingency situations and would do nothing to alleviate the loading and reliability issues on the existing RVC distribution system. Under this scenario, additional distribution capacity could only come through the replacement of existing transformers with larger capacity transformers. This option would require extensive transformer cabling and bus reinforcement as this equipment is just sized to meet existing conditions, and has no additional capacity.

Option 2: New RVC Tap Option

This option utilizes LIPA's newly operating 33kV line between the Bellmore and Ocean Avenue Substations that is routed along the pole line on the LIRR right of way immediately adjacent to the RVC Maple Avenue Substation. Under this scenario, a second interconnection point with LIPA would be created by essentially having the 33kV line tie into a new (and 2nd) Maple Avenue Substation (Figure 4). This substation would include the 33kV line and bus tie breakers necessary to provide for the reliability of both the LIPA and RVC systems, and would enable the creation of a new 33/4kV distribution substation. The substation would consist of 2-10MVA 33/4kV distribution transformers with at least 6- 4kV distribution feeders (Figure 4A). Some of the existing tandem or tertiary connected distribution circuits from the existing substation would be reconnected to this substation, with spares for future new circuits when needed. The benefits of this option are that it solves both transmission and distribution issues and provides RVC with much greater operating flexibility. Currently, RVC must physically balance internal generation and feeder/bus loadings in order to maximize economic import capability.

This scenario will require the approval of LIPA to establish a secondary point of interconnection and to allow their transmission line to "run through" a substation owned by RVC. It is also likely that LIPA would require the 33kV breakers in this new substation to be under their supervisory control for normal monitoring and contingency operations.

Components for Options 1 and 2

Option 1: RVC – Ocean Avenue 3rd Supply Option

- ✓ Install 69kV UG cable (operating at 33kV) between Ocean Ave and RVC (Maple Ave Sub)
- ✓ Install 33kV line breaker at Ocean Ave
- ✓ Install 33kV line breaker at RVC (utilize spare compartment)
- ✓ Install 33kV bus tie breaker at RVC
- ✓ Replace 2-5 MVA 33/4kV transformers with 2-15 MVA 33/4kV transformers
- ✓ Reinforce 4kV low side cable from new transformers to 4kV bus to 2000A capacity
- ✓ Replace 4kV incoming breakers N23 and S23 with 2000A breakers
- ✓ Add 4-4kV distribution breakers to existing spare cubicles
- ✓ Reconfigure 4-4kV feeders from their current tandem configuration to single breaker configurations

Option 2: RVC Tap Option

- ✓ Tap newly configured 33kV OH line between Bellmore and Ocean Ave Subs
- ✓ Install new RVC Substation consisting of:
    - o Install 33kV bus
    - o Install 2-33kV line breakers
    - o Install 1-33kV bus tie
    - o Install 2-33kV high side breakers for transformers
    - o Install 2-10 MVA 33/4kV transformers
    - o Install 4kV switchgear consisting of 2-2000 A incoming breakers, 4-600 A distribution ACB's and 2 spare cubicles for future use
    - o Install relay/supervisory control integration with RVC and LIPA

In both cases a new substation is required at an estimated cost of $2.3 million. Further definition of costs for either of the transmission options must be obtained from LIPA.

VI. Conservation and Load Management

1. *Investigation of Demand-Side Options*

Demand-side management, or DSM, refers to programs or projects undertaken to manage the demand for electricity: reducing electric energy use, changing the timing of electricity use (and thereby the profile of peak power demand), or both. By reducing the demand for electric energy and power, DSM options can reduce the use of existing electric supply facilities (or, equivalently, serve more users with given facilities), and defer the addition of new capacity. Review of DSM options begins with identification of all applicable options and their cost and performance characteristics. The more promising DSM options are selected for further study and incorporation in draft DSM programs and plans.

2. *DSM Options*

The list of potential DSM options for utility systems is longer than the list of supply options. DSM options can be roughly divided into three categories, as follows.

A. Information and/or Incentives to Encourage Efficiency in Electricity Use

One class of options is to provide information to electricity consumers on how to use energy wisely and efficiently, and to provide pricing structures that help spur customers to change the amount and timing of energy use. Although there is uncertainty in the estimates of electricity or peak power savings from all types of DSM measures, the savings from information/price incentive measures are perhaps hardest to quantify.

B. Higher-efficiency Technologies

Another class of options is energy-efficiency measures. These are technologies that reduce energy use (usually with some reduction in peak loads) by substituting more efficient appliances and equipment for less-efficient units or systems. Energy efficiency measures are available for virtually every end-use application. A small sample of generic measures, organized by sector (customer group), is presented below.

Selected End-Use Electric Energy Efficiency Measures
Residential Sector
- Higher-efficiency appliances (air conditioners, refrigerators, stoves, water heaters, electronic devices)
- Devices that save hot water (efficient washing machines, plumbing fixtures)
- Compact fluorescent lamps

• Automatic lighting controls
• Building envelope improvements (insulation, window improvements) to reduce cooling, heating, and sometimes
lighting needs.

Commercial/Institutional Sectors

• Higher-efficiency air conditioning, refrigeration equipment
• High-efficiency fluorescent bulbs, lamp ballasts, and lighting fixtures
• Lighting, cooling, space heating, and water heating controls
• High-efficiency office equipment
• Building envelope improvements
• High-efficiency electric motors, drives, and controls

Industrial Sector

• Process improvements
• High-efficiency electric motors, drives, and controls
• Applicable commercial/institutional sector measures

Other Sectors

• High-efficiency cooling and refrigeration equipment for the agricultural sector
• High-efficiency electric motors, drives, and controls for mining and transport applications
• High-efficiency lighting products for street lighting

C. Load Management

Load management measures reduce peak demand by shifting power use from times of high power demand (for example, during the day or early evening) to times of lower demand (during the night). Examples include:

- **Controllers for household applications**. These can be simple timers that turn off appliances during peak times, or electronic controls (load control.) activated by the utility system operator. With centrally activated load control systems, different groups of end-use equipment can be cycled off for a few minutes during each peak load hour.
- **Special interruptible rates**. Large volume electricity users may be offered price discounts in exchange for allowing the utility to disconnect all or a portion of their electrical equipment when the utility system is short of generating capacity.

Attributes of DSM Options

It is necessary to collect data on DSM options so that they can be compared with each other and with supply-side options. Attributes of DSM options that need to be considered are described as follows:

- **Applicability.** To what sectors and end-uses can the DSM measure be applied? What is the size of the market for which the measure is applicable?

- **Fuel type.** For fuel-switching measures, what fuel is used?
- **Reliability and lifetime.** How has the measure performed in previous applications? What is its typical lifetime?
- **Efficiency.** How much energy and power does the measure save, relative to standard equipment?
- **Capital and operating costs.** What does it cost to own, operate, and maintain the technology?
- **Environmental impacts.** What are the impacts of the technology, relative to standard equipment?

In reviewing DSM options for Rockville Centre the degree to which implementation of proven techniques of conservation and load management might impact the projected need for additional capacity requirements must be explored. Over the next 20 years, peak load is expected to grow to between 51Mw and 55 Mw. Based on previous tasks, additional capacity or purchases of power to meet both customer needs and ICAP requirements is needed.

Rockville Centre is comprised primarily of residential and small commercial customers. In addition, the majority of opportunities for conservation would result from retrofitting existing customers' facilities which is both expensive and limited in the amount of savings which can be realized.

While certain programs (which are discussed below) can be beneficial both in terms of customer participation and cost, the potential impact that these programs can have on Rockville Centre's capacity requirements is not projected to be significant. Rockville's Centre's existing power supply has reached is limit to satisfy load growth and ICAP requirements.

The programs which warrant further consideration for Rockville Centre are controllers for both central and room air conditioning systems. Typically, such programs can cost effectively impact peak demand by approximately 1Kw per participating residential customer. (Savings are even greater for small commercial loads, but there is little field experience with these types of programs.) Because LIPA is implementing a similar load control program for its residential customers, it may be possible for Rockville Centre to participate as a partner in LIPA's programs, thereby reducing costs.

VII. Conclusions and Recommendations

This study presents options available to the Village of Rockville Centre for meeting future growth requirements. Options evaluated include new supply, transmission system upgrades and implementing conservation and load management initiatives.

Based on the evaluations presented, which are keyed to a revised forecast for the Village, a mix of new generating capacity and additional import capacity is recommended. Such a combination will provide the Village with a strategy that is sound from both reliability and financial concerns.

Our recommendation is to retire Units 7 and 8, add two 2.8Mw engine generators (Option 1 as defined in the Supply Analysis section) and to purchase ICAP. This will provide the necessary capacity as required by the New York Independent System Operator. A new substation is also recommended to allow energy imports above the current 29Mw limit and to alleviate the "shared" distribution breakers.