INDIANTOWN

Gas company, inc.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030954-GU

DIRECT TESTIMONY
& EXHIBITS

VOLUME I

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY

OF BRIAN J. POWERS

ON BEHALF OF INDIANTOWN GAS COMPANY, INC

DOCKET NO. 030954-GU

DECEMBER 2003

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Brian J. Powers. My business address is Indiantown Gas Company, Inc., P.O. Box 8, Indiantown, FL 34956

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the President of Indiantown Gas Company, Inc. ("IGC" or the "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I graduated from the University of Florida in 1988 with a Bachelor of Science degree in Food and Resource Economics.

Q. PLEASE DESCRIBE YOUR WORK EXPERIENCE PRIOR TO BECOMING PRESIDENT OF IGC.

A. IGC was founded as a propane distribution company by my family in 1960. The natural gas operation began in 1970. I grew up working in the business. Because we were a small family-owned business I developed a hands-on familiarity with all facets of the Company - from operations to customer service to accounting. My involvement in the natural gas industry continued during college. Concurrent with my studies at the University of Florida, I interned at Gainesville Gas Company in the accounting department. My responsibilities included accounts payable preparation, preparation of financial statements, and assisting their internal audit team. Following graduation, I continued to work in the Gainesville Gas accounting department through their acquisition by the City of Gainesville. I became the General Manager of Indiantown Gas Company in 1991. As General Manager, I was responsible for the day-to day operation of the Company. In 1999, I was appointed President of IGC.

Q. WHAT ARE YOUR CURRENT DUTIES AS PRESIDENT OF IGC?

A. My duties as President include managing all facets of the Company's operations including: strategic planning; preparation of capital, revenue and operation and maintenance budgets; natural gas operations; human resources; engineering; sales and marketing; customer service; accounting functions and regulatory activities.

Q. PLEASE DESCRIBE CIVIC AND COMMUNITY ORGANIZATION INVOLVEMENT RELEVANT TO THIS FILING.

A. I am active in the Indiantown Western Martin County Chamber of Commerce. Among other roles I serve as the Immediate Past President of this organization. I also serve as the Chairman of the Indiantown Neighborhood Advisory Committee. This Committee is a quasi-governmental arm of the county government assigned to perform development review and community redevelopment plans for the Indiantown area.

Purpose of Testimony and Organization of Case

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will generally describe the Company, its operations, and its customer base. I will explain the need for immediate rate relief, both on an interim and permanent basis, primarily due to attrition and the substantial reduction in transportation sales to the Company's largest customer, Indiantown Cogeneration, L.P. I will address the proposed retention of the Company's current rate of return on common equity. I will describe the steps taken to avoid a rate increase. My testimony will describe the Company's capital budget requirements during the Projected Test Year. I will address several specific increases in historic operating costs. In addition, I will describe certain increases in operating expenses required to maintain the Company's distribution system, meet customer service expectations and comply with regulatory mandates. Finally, I will provide an overview of the market area and address future economic trends for the Company's service territory.

Q. IN ADDITION TO YOUR TESTIMONY, WHAT INFORMATION IS IGC FILING IN SUPPORT OF ITS RATE REQUEST?

A. IGC is filing the Minimum Filing Requirements ("MFRs") required by the Commission's rules. IGC is also filing the testimony and exhibits of

Melissa M. Powers the Company's CFO, and Jeff Householder, the Company's consultant in this rate case.

Q. ARE YOU SPONSORING ANY OF THE MFR SCHEDULES?

A. Yes. All of the Company's MFR schedules were prepared under my direction, supervision and control. However, for purposes of this rate case, I am sponsoring the MFR schedules identified in Exhibit ____ (BJP-1).

General Overview of the Company

Q. PLEASE PROVIDE A GENERAL OVERVIEW OF INDIANTOWN GAS COMPANY.

A. IGC is a Florida corporation that was incorporated on May 1, 1960. The Company is a natural gas local distribution company that is subject to the Commission's regulation under Chapter 366 F.S. The Company's initial tariff was approved in August 1970 by Commission Order 4933 in Docket No. 70377-GU.

Q. WHAT TERRITORY DOES THE COMPANY SERVE?

A. IGC's service territory includes the City of Indiantown and the unincorporated community of Booker Park in Martin County, Florida, and territories adjacent thereto.

Q. PLEASE DESCRIBE THE CUSTOMER BASE SERVED BY THE COMPANY.

A. IGC serves approximately 684 total customers on its system. The customer mix is comprised of: 660 residential customers who account for approximately 3.1% of total throughput; 22 commercial customers who account for approximately 2.6% of total throughput; and 2 industrial customers who account for approximately 96.3 % of total throughput.

The two IGC industrial customers are Indiantown Cogeneration and Louis Dreyfus Citrus (an orange juice processing facility). Historically, the cogeneration plant was, by far, the largest customer on the Company's system. The plant initiated commercial operations in December 1995. Annual gas consumption has ranged from a high of almost 9,700,000 therms in 1996 to a low of approximately 2,482,000 therms in 2002. Projected consumption for 2003 should reach approximately 2,600,000 and continue at that level in 2004. The Company has historically served the cogeneration plant through a Special Contract approved by the Commission. The contract stipulates that rates for service are to be based on the applicable volumetric rate schedule in the Company's tariff, as may be revised by Commission action from time to time. A recent renegotiation of this Agreement was approved by the Commission on October 20, 2003 (Order No. PSC-03-1156-PAA-GU). The new agreement converted the plant to transportation service and established a Maximum Daily Transportation Quantity (MDTQ) of 9500 dekatherms (Dt).

The citrus facility currently owned by Louis Dreyfus began operations in 1972. Annual gas consumption at the facility has been relatively stable over the past few years. Over the three-year period 2000-2002 the citrus facility averaged 2,163,262 therms. We expect consumption to reach approximately 2,200,000 therms for 2003 and are projecting the same quantity for 2004. Louis Dreyfus is served under a tariff Transportation Service Agreement, at tariff rates. The citrus facility experienced a peak day requirement of 1550 MCF (1612 Dt) over the past two years.

Q. WHAT IS THE CURRENT STATUS OF UNBUNDLING ON THE COMPANY'S DISTRIBUTION SYSTEM?

A. On November 26, 2002 the Commission approved (Order No. PSC-02-1655-TRF-GU) IGC's petition to transfer all remaining sales customers to transportation service and exit the gas merchant function. The program was approved on an experimental basis. The IGC tariff authorized by the Commission provides for two levels of transportation service. Large volume customers using over 25,000 therms per year may elect to transport on an individual basis. All customers using 25,000 therms or less per year, including residential customers, are served as part of an aggregated customer pool.

The Company participated in a joint Request for Proposals (RFP) process with Chesapeake Utilities Corporation and selected a gas marketer (Infinite Energy) to serve as the Pool Manager for small volume customers. Customers eligible for Individual Transportation Service may elect to join the aggregated customer pool, subject to acceptance by the Pool Manager. To simplify the transition for its customers, the Company bills the Infinite Energy fuel supply charges on its regular monthly statements. In addition, IGC provides a variety of administrative services to the Pool Manger (payment processing, collections, consumption tracking, maintenance of customer account information, etc.). IGC charges an authorized fee of $2.00 per bill to the Pool Manager for the billing and administrative services.

The Company's transportation programs have been well received by customers. Program implementation and the transition of customers to transportation were virtually seamless. On October 6, 2003 the Commission approved (Order No. PSC-03-1109-PAA-GU) IGC's petition for the final disposition of the remaining balance of its Purchased Gas Adjustment account. In the same Order, the Commission also authorized the recovery of certain non-recurring program development costs through a Transportation Cost Recovery surcharge.

Requested Rate Relief

Q. WHAT IS THE AMOUNT OF THE PERMANENT RATE INCREASE IGC SEEKS IN THIS CASE?

A. To restore a reasonable rate of return on its investment, the Company is seeking a permanent annual rate increase of $306,757, representing an overall increase of 89.45%. The calculation of IGC's permanent revenue requirement is addressed in Ms. Power's prefiled direct testimony.

Q. **ON WHAT PROJECTED TEST PERIOD IS IGC BASING ITS REQUEST FOR A PERMANENT CHANGE IN BASE RATES?**

A. The projected test period consists of the twelve months ending December 31, 2004. In accordance with the Commission's requirements, the MFR's include financial information for the "historic base year" (2002), the "base year +1" (2003) and the "projected test year" (2004).

Q. **IN YOUR OPINION, IS THE PROJECTED 2004 TEST YEAR AN APPROPRIATE TEST PERIOD FOR SETTING RATES?**

A. Yes. This period best reflects the customer forecast, sales levels and overall cost of service that IGC will experience during the period in which the rates established in this proceeding will be in effect. As described in greater detail in Mr. Householder's testimony, the Company experiences little net growth in customers from one year to the next. Sales volumes in the non-industrial commercial classes have been stable for years. Industrial sales volumes have decreased as a direct result of Indiantown Cogeneration operational changes. At present, it appears that the cogeneration facility volumes have stabilized. Extensive discussions with plant management have indicated no plans to increase consumption. The likelihood of further load deterioration is greater than any increase in sales volume. In short, the customer and revenue forecast is virtually flat for the foreseeable future. Our costs have been reduced, through financial necessity, to bare minimum levels. The expense level increases we seek simply return the Company to a reasonable operating standard. With the increase in proposed rates, and retained earnings, our capital structure will stabilize. The Company's fiscal year corresponds to the calendar year. The selection of calendar year 2004 as the Projected Test Year also allows IGC to use readily available financial and statistical data from its 2002 fiscal year to represent the Historic Base Year.

Q. IS IGC SEEKING AN INCREASE IN ITS AUTHORIZED RETURN ON EQUITY?

A. No. The Company's current authorized return on common equity is set at 11.5%. The Commission approved the current rate in the Company's 2002 rate restructuring proceeding (Order No. PSC-02-1666-PAA-GU). IGC proposes that in this proceeding the Commission authorize the continued adoption of the Company's current 11.5% rate. In keeping with the Commission's past practices, authorization of an 11.5% ROE provides the mid-point for an authorized range of plus or minus 100 basis points.

The Company has elected not to retain the services of a cost of capital consultant. In the Company's view the substantial expense of including a cost of capital witness in this case is not warranted. Since 2000, the Commission has conducted cost of equity reviews in the disposition of several natural gas rate cases. In the Chesapeake Utilities Corporation (CUC) base rate case the Commission authorized an 11.5%

ROE (Order PSC-00-2263-FOF-GU). In the St. Joe Natural Gas Company (SJNG) base rate case the Commission also authorized an ROE of 11.5% (Order No. PSC-PSC-01-1274-PAA-GU). Finally, the recent rate filing by TECO Peoples Gas resulted in an authorized ROE of 11.25% (Order No. PSC-03-0415-FOF-GU). While TECO Peoples Gas is a much larger company, in my view, IGC and SJNG and, to a great extent even CUC, exhibit similar operating characteristics and business risks, factors important in assessing an appropriate cost of capital.

CUC is a relatively small company. Both IGC and SJNG are extremely small companies. The finance literature consistently documents that small companies generally exhibit greater investment risk than larger firms. The limited ability to absorb customer and load loss (especially of large core accounts), general lack of revenue diversity, economic slowdowns that affect growth or retention, managing gas supply/capacity arrangements in the post FERC 636 market all define increased risks for small companies. Revenues at IGC, SJNG and CUC are heavily tilted toward the industrial market sectors. All three companies have experienced industrial customer or load loss that has required a restructuring of base rates. Additional industrial risk continues to exist in each company. Competition from alternative fuels and the relative risk of by-pass by large accounts is similar in each company.

CUC determined that, as one means of reducing business risk, it must grow its customer base to diversify revenues and more appropriately spread fixed operating costs. IGC's opportunities to reduce the reliance on industrial customers by expanding its existing distribution system to serve new customers are extremely limited at this time. Any potential expansion to serve new areas would likely involve a new interstate pipeline interconnect and miles of main extension well removed from its existing distribution system. Unfortunately, the very nature of substantial expansion of the distribution system for a small company also exposes it to significant risk. Cost overruns or delays in project build-outs can dramatically affect the recovery of gas extension investment costs. For companies of IGC's size, any delay in revenue can be catastrophic.

There are two fundamental principals that should guide the establishment of returns on equity. One, companies will not be able to attract capital for investment or to maintain financial integrity unless they can provide returns (or make interest payments) at rates that are similar to alternative investments gauged to have comparable risks. Two, companies will not invest in assets unless the expected return exceeds their cost of capital. The Commission should, in my view, set rates of return that recognize both of these principals.

I believe that my company's total risks are higher than those of most LDCs at this time. I know that our current financial position is providing an unreasonable return for the company's shareholders. I am concerned that we are reaching the point where we lack the financial strength to attract capital at reasonable rates. My greater concern is that, absent Commission action, IGC will struggle to reliably meet customer expectations for service in our community. I want to continue to provide quality service to existing customers. I believe allowing the IGC to retain its current ROE will significantly contribute to the restoration of the Company's financial well-being. In my opinion, the IGC risk profile and general character of service warrant the authorization of an 11.5% mid-point rate of return on common equity.

Q. IS IGC ALSO SEEKING INTERIM RATE RELIEF?

A. Yes. Using the Commission's methodology, the Company requests interim rate relief in the amount of $131,896 based on a historical base year ending December 31, 2002. The calculation of IGC's interim revenue requirement is addressed in the testimony of Melissa Powers. Mr. Householder's testimony discusses the allocation of the interim increase to the Company's existing customer classes.

Need For Rate Relief

Q. WHY IS IT NECESSARY FOR IGC TO SEEK RATE RELIEF AT THIS TIME?

A. There are four principal reasons the Company is seeking rate relief at this time.

1) As I mentioned above, the Company has experienced a dramatic loss of transportation volume to its largest industrial customer

(Indiantown Cogeneration) and the revenues associated with those volumes.

2) The gas industry has changed dramatically since 1970, especially with the advent of open access transportation service. The service challenges of today's regulatory and market environments have resulted in new costs that are appropriately recovered by the Company.

3) The affects of attrition over the 34 years since the Company's last base rate case should be addressed.

4) Given the significant reduction in earnings over the past three years, the Company has appropriately deferred, delayed and postponed the purchase or replacement of several items important to providing reliable service to customers. The Company has redirected resources to ensure that safe operation of the system was always addressed. A return to financial stability will enable the Company to afford those capital and expense items necessary to improve customer service, continue to provide lower cost fuel through aggregated transportation and retain skilled employees.

Q. ARE THE COMPANY'S CURRENT RATES PRODUCING REVENUES SUFFICIENT TO YIELD AN ADEQUATE RETURN ON THE COMPANY'S INVESTMENT?

A. No. At the time of the IGC's 2002 rate restructuring the filed cost of service study indicated that the Company's rate of return had deteriorated to -3.1%. Given the continued reduction in revenue from the cogeneration plant subsequent to the restructuring, the Company's returns have not improved. As described by Mr. Householder in his cost of service study, the forecast rate of return at present rates in the Projected Test Year plummets to -30.5%. Returns from the industrial service customers in the current TS-4 class are projected at -42,2%. If not quickly resolved, this deficiency in earnings will worsen an already serious cash flow problem and necessitate the use of additional debt to support normal operations. The revenue shortfall is having a direct affect on retained earnings and a corresponding negative affect on the Company's equity position in its projected capital structure is significant. The revenue shortfall crisis confronting IGC imposes a hardship on the Company and has begun to affect its ability to serve customers. Rectifying this problem on an expedited basis is the primary objective of this rate case.

Q. PLEASE PROVIDE A BREIF HISTORICAL OVERVIEW OF THE COMPANY'S INDUSTRIAL CUSTOMER BASE.

A. As noted above, the Company began operations and established its original rates in 1970. The major anchor customer at that time was Florida Steel, a rebar manufacturer, using approximately 6,000,000 therms per year. In 1972 Caulkins Citrus opened a juice processing facility that over the next twenty-years grew to approximately 6,000,000 therms annually. The Company served both Caulkins and Florida Steel on its Large Interruptible Service (LIS) rate. In 1976 the steel plant closed. During the 1980's and early 1990's the Company also added approximately 125 new residential and small commercial customers.

By the mid 1990's the Caulkins consumption growth and the Company's relatively minor growth in customers had stopped. Inflation and a general increase in the cost of various products and services had eroded the company's earnings to the point it was contemplating a rate filing. However, in 1995 the construction of Indiantown Cogeneration significantly changed the Company's business. Caulkins became the steam host for the cogeneration plant and subsequently reduced its gas consumption from over 6,000,000 therms to less than 2,000,000 per year. At the same time the cogeneration plant ramped up to over 9,000,000 therms.

The cogeneration plant was originally served under the same industrial interruptible rate as Caulkins. Given the substantial operational changes required to become the steam host and the corresponding reduction in gas usage Caulkins expressed an interest in receiving firm service. The Company petitioned to establish a new Firm Industrial Service (FIS) rate for Caulkins. The FIS rate was approved by the Commission on December 2, 1996 (Order No. PSC-96-1452-FOF-GU). The new rate reduced the Caulkins Customer Charge from the existing LIS rate of $4,500 per month to $1,200 per month. The variable per therm charge for the new FIS class was set at the same level as the existing LIS rate, $0.452.

From 1999 to mid-year 2000 the Company's rates produced reasonable returns. However, the cogeneration plant began reducing its consumption in mid-2000. By the beginning of 2002 it was clear to the Company that the reductions were permanent, although it appeared for a time that usage would stabilize around 4,000,000 therms per year. Although revenues had decreased significantly, the Company, with its limited resources, was reluctant to pursue a full rate proceeding. It elected to file a rate restructuring and appropriately shift some of the cost recovery burden to the residential and small commercial classes. The Commission approved the Company's restructuring on November 26, 2002 (Order No, PSC-02-1666-PAA-GU). The cost study submitted to the Commission during the restructuring indicated a return of –3.1%. Subsequent to the 2002 rate restructuring, the cogeneration plant's volumes dropped by an additional 1,500,000 therms. The Company's returns have continued to drop.

Q. WHAT CAUSED THE COGENERATION PLANT TO REDUCE ITS VOLUMES SO DRAMATICALLY?

A. The loss of load at the cogeneration plant can be directly attributed to the substantial rise in natural gas commodity prices beginning in early 2000. Exhibit No. ___ (BJP-2) clearly illustrates the dramatic and historically unprecedented increase in gas prices in 2000-2001. The monthly index price in $/MMBtu increased from around $2.50 to over $9.00 in late 2000. After fifteen years of relatively stable pricing, rarely exceeding

$3.00 per MMBtu, prices shot up and have remained at unusually high levels (above $4.00/ MMBtu). The plant's primary fuel is coal. Natural gas is used principally for flame stabilization and during a cold start of the boiler after an outage. When the plant began operations in 1995, the objective was to leave some gas burning in the boiler at all times to ensure that the boiler would not trip due to low Btu content coal, coal with high moisture content, or other operating factors.

The winter 2000-2001 gas price escalation provided an incentive for the plant's management to look for ways to cut gas usage. Several physical improvements to the plant's burners were undertaken. Additional operating measures improved plant efficiencies and also reduced gas requirements. These improvements are permanent. Gas prices retreated at the end of 2001 and the beginning of 2002. However, gas volumes at the plant continued to decrease. The migration of the cogeneration facility to transportation service has also contributed to lower consumption. In a transportation environment the plant is forced to monitor and schedule gas on a frequent, often daily, basis. This increased attention promotes conservation. The plant has reduced its current consumption by over 70% compared to 1999 volumes. The loss of revenues from Indiantown Cogeneration has had a devastating negative impact on the Company's ability to recover normal operating costs and earn a fair return on its investment.

Q. PLEASE DESCRIBE THE LOSS OF REVENUE FROM INDIANTOWN

COGENERATION?

A. The reduction in consumption at the cogeneration facility began in 2000. The prior year the plant used over 9,000,000 therms and contributed approximately $465,000 in margin revenue. By the end of 2000 consumption had been reduced to approximately 6,800,000 therms. Total volumes dropped again in 2001 to approximately 4,500,000 therms, and to 2,482,000 therms in 2002. In 2003 using actual volumes through November and projecting December the plant will burn less than 2,600,000 therms. Margin contribution in 2003 will have declined to approximately $150,000. Given its consumption level over the past two years, the plant qualified to move into the TS-4 class (100,000 to 3,000,000 annual therms). The therm forecast for 2004 is 2,600,000 therms. This consumption level at the present TS-4 rate would produce less than $115,000 in margin.

Q. YOU INDICATED THAT CHANGES IN THE GAS INDUSTRY HAVE ALSO RESULTED IN INCREASED COSTS TO IGC. PLEASE BRIEFLY DESCRIBE THE CHANGES AND RELATED COST INCREASES.

A. Federal initiatives, culminating in FERC Order 636, substantially altered the long-standing market relationships between producers, transporters, distributors and customers. Transportation service has become commonplace for most non-residential customers, and In IGC's case, for all residential customers. This restructuring of the gas industry has required gas distributors to operate in a significantly more complex business environment. As interstate pipelines discontinued gas merchant functions, LDCs assumed a variety of new responsibilities, including purchasing gas supplies, reserving capacity on the interstate pipeline, and scheduling and controlling daily gas flows. The costs of providing such services were also shifted to the LDCs.

The regulatory and general business environments in which the Company operates have also become more complex and require the commitment of additional resources. For example, the Commission has adopted several rules over the past few years that significantly impact the Company. The updating of distribution system maps to include all service lines (Rule 25-12.061), the meter testing and meter record rules (25-7.064 and 25-7.021) and a variety of other record keeping and reporting requirements have a significant impact on the Company. Numerous Federal DOT regulations in Title 49 CFR Part 192 for Operator Qualifications, Drug Policies, and a multitude of operational standards and reporting requirements add to the Company's administrative burden.

I recognize that such regulations and business practices are appropriately adopted to ensure the safe, reliable operation of gas distribution systems. They do, however, come at a cost. Small companies, such as IGC, have a limited ability to absorb such costs. Our rate filing proposes to address some of these concerns through the addition of staff and improvements in the Company's computerized information systems.

Q. HAS THE COMPANY TAKEN STEPS TO AVOID A RATE INCREASE?

A. Yes. For several years, IGC has taken various actions designed to retain its existing industrial customer base and to decrease the threat of customer bypass. The 2002 limited proceeding to restructure rates discussed above was designed to retain existing industrial customers and volume, and move toward greater equity among rate classifications. IGC has also entered into special service agreements (approved by the Commission) with its existing large industrial customers in an effort to retain those customers and the associated revenue. The Company's transfer of its customers to transportation service in December 2002 is another specific example of an effort to reduce the overall cost of gas to customers to encourage the retention of load. The cogeneration plant has received substantial benefits from transportation. The year prior to the initiation of the program, the plant received over $200,000 in FGT Alert Day penalties from IGC. In 2003, to my knowledge, they have paid few if any Alert Day charges.

Q. HAS IGC TAKEN OTHER ACTIONS TO RETAIN ITS INDUSTRIAL CUSTOMER REVENUES AND MITIGATE THE NEED FOR RATE RELIEF?

A. Yes. The Company has made every reasonable effort to avoid seeking a rate increase. IGC has implemented extraordinary cost savings measures including: curtailing increases in operating costs, limiting or delaying staff salary increases, postponing the addition of operations and customer service staff, discontinuing the practice of hiring seasonal and part-time employees, delaying the needed replacement of utility vehicles, ceasing the payment of dividends to shareholders, and foregoing making any contributions to the Company's 401K retirement plan for the first time since the creation of that plan.

Q. YOU ALSO INDICATED THAT THE COMPANY HAS DEFERRED OR POSTPONED SEVERAL IMPORTANT CAPITAL AND O&M EXPENSES AS A RESULT OF ITS REDUCED FINNANCIAL CAPABILITY. PLEASE ELABOATE.

A. The following sections of my testimony provide detailed descriptions of the Company's 2004 capital budget as well as proposed increases in expenses beyond trended levels. Most of the items included in the capital list are for vehicles, tools and equipment that are due or overdue for replacement, i.e. they meet or exceed the approved depreciation life of the asset. The expense items primarily allow the Company to return to a normal staffing level and continue to fund employee retirement programs.

Capital Budget (Projected)

Q. WHAT IS THE AMOUNT OF THE COMPANY'S CAPITAL EXPENDITURES PROJECTED THROUGH THE END OF 2003?

A. The company's capital budget for the year 2003 was $39,755 as reflected in Schedule G-1 of the MFRs. Of the total, $36,807 was allocated to mains, service lines and meters related to the Company's bare steel and meter replacement activities. An additional $2,948 reflects the transfer of the book value of the Company's office building property from non-utility operations to the utility.

Q. WHAT IS THE AMOUNT OF THE COMPANY'S PROJECTED CAPITAL EXPENDITURES FOR 2004?

A. The company has projected a capital budget for the year 2004 of $217,987 as reflected in Schedule G-1 of the MFRs.

Q. PLEASE DESCRIBE THE MAJOR ITEMS INCLUDED IN THE COMPANY'S PROJECTED CAPITAL EXPENDITURES FOR 2004.

A. The following expenditures are included in the capital budget for 2004.

- $42,500 in Transportation Equipment for a heavy-duty pick-up truck to replace an existing, 1998 Ford pick-up truck. This vehicle would be primarily used by the President. Given the size of the Company and limited number of employees, the President is heavily involved in the physical operation of the system. His existing truck is used on a daily basis to transport meters, tools, equipment and other items related to the construction, maintenance and operation of the distribution system

- $42,500 in Transportation Equipment for a heavy-duty pick-up truck to replace an existing fully depreciated 1996 Dodge pick-up truck used for construction, service and maintenance.
- $16,500 in Power Operated Equipment for a replacement backhoe. The existing small backhoe was purchased used in 1996. It is only marginally operational at this time. The Company again plans to purchase a previously owned backhoe replace the current unit.
- $42,750 for a new Customer Information System (CIS). The Company's current computer system has been pieced together over ten years from several sources of software. The technical support experts retained by the Company to maintain the system and implement periodic revisions have recommended replacement. The current system has a limited capability to handle the customer accounting, reporting and billing requirements required in a transportation only environment. Additionally, many of the record and reporting requirements established by the Commission are not supported by our existing system. For example, the meter record system to provide the information required by Commission Rule 25-7.021 Records of Meters and Meter Tests, FAC, is a manual process in the Company. The primary functionality of our existing system was installed in 1993 and is fully depreciated. It is simply not practical to continue operating with such archaic software.

- $37,700 for Tools, Shop and Garage Equipment. A detail of the expenditures projected for this category include:
  - $16,500 for a back-up gas–fired generator for the Company office. The existing generator is no longer operational.
  - $12,500 for a portable, trailer mounted air compressor required for pressure testing pipe systems.
  - $6,500 for replacement safety equipment (Combustible Gas Indicator, Flame pack and oderometer).
  - $2,200 for a replacement underground line locator.
- $8,250 for new meters required for the meter replacement program described below and for ten new services projected during 2004.
- $180 for the meter installations related to ten new residences forecast for 2004.

Q. PLEASE DESCRIBE ANY SYSTEM IMPROVEMENTS THAT MAKE UP PART OF THE 2004 CAPITAL-SPENDING PLAN.

A. The Company's 2004 capital plan includes funds for replacing bare steel mains and services, and for installation costs related to meter replacements.

- $13,404 for bare steel main replacement. The Company has an on-going main replacement program. Approximately 3000 feet of bare pipe remains in-service. Removal of all bare steel pipe is scheduled for completion by December 2005.

- $12,691 for bare steel service line removal. Approximately 58 services remain to be replaced. Completion id scheduled for December 2005.
- $1,512 for meter installation costs related to compliance with Commission Rule 25-7.064 Periodic Meter Test, FAC, Subparts 1 and 2. The Commission noted in a letter to the Company on May 16, 2003 that an accelerated meter test program should be initiated and the Company brought into full compliance with the rule by December 31, 2005.

Q. PLEASE DESCRIBE ANY SIGNIFICANT ADDITIONS TO THE COMPANY'S HISTORIC O&M EXPENDITURES PROJECTED FOR 2004.

A. First let me say that our expenses for operations and maintenance have been substantially reduced over the past two years as revenues have declined. In my view it is not appropriate to assume that a trending of expenses over the recent past will point to an appropriate level of future expense for the Company. While the O&M expenses that I describe below represent an increase in costs compared to 2002 or 2003, they are primarily intended to return the Company to the basic level of staffing and employee benefits that existed in the past. In my view the level of service that we owe our customers requires that we provide the customer service, operations and administrative support that has been historically available to Indiantown Gas customers. The level of annual

O&M expenditures projected for 2004 above the trend amounts include the following items:

- $13,498 in Account 874 (50% FTE) Construction/Maintenance Worker. The remaining 50% FTE would be capitalized.
- $9,380 in Account 800 (50% FTE) and $9.380 (50% FTE) in Account 889 for a Customer Service Representative.
- $14,000 in Account 920 (25% FTE) to increase Melissa Powers' work schedule from one-half to three quarter time. Ms. Powers' is principally responsible for administering the Company's Aggregated Transportation Service Program. The increased reporting, customer information, and accounting functions directly related to the program have necessitated the increase in work hours. These are recurring, on-going activities unrelated to the one-time expenses the Company is recovering in its authorized TCR mechanism (Order No. PSC-02-1655-TRF-GU). Jeff Householder's testimony describes the Company's proposed allocation of these costs to the new Third Party Supplier (TPS) rate class. Establishing the TPS class would enable the Company to recover its recurring increased costs from the gas marketers benefiting from the administrative services we are providing.
- $7,000 in Account 926 to reinstate the Company's contribution to its employee 401K program. Company contributions were suspended for the 2002 fiscal year and, given current financial

conditions, it is unlikely that contributions will be made for the 2003 fiscal year.

- $5,400 in Account 920 to meet actuarial requirements in the Company's defined benefits retirement program. This program is closed to new entrants. The plan administrator has informed management that an increased contribution is needed to meet the expected future payout requirements of the plan.
- $18,000 in Account 930 for Directors Fees. The Company currently has three non-employee Directors that actively participate in establishing strategic and budget objectives as well as setting the overall direction and policies of the Company.
- $25,013 in Account 928 for the amortization of rate case expenses over a proposed four-year period.

Q. IN YOUR OPINION IS THERE A FUTURE OPPORTUNITY TO ADD CUSTOMERS IN THE IGS SERVICE AREA?

A. Yes. It appears that over the next decade that the western areas in the County may began to grow. Indiantown is situated along the St. Lucie canal, a navigable waterway connecting Lake Okeechobee to the Atlantic Ocean. As developable land in Palm Beach and Martin counties becomes scarce and high priced, there may be efforts to develop property around Indiantown, especially along the canal. The recent announcement that the Scripps Institute plans a major medical research facility in north west Palm Beach County may give some impetus for growth in Indiantown. In addition, Indiantown and the surrounding area offer good locations for industrial development away from the population centers closer to the coast. Unfortunately, it is not likely that any significant development will occur in the near future that will affect IGC's customer base or revenues. I remain optimistic that before the end of this decade we will begin to see opportunities to serve growth in the Company's territory.

Q. IS THE COMPANY REQUESTING SUBSTANTIVE REVISIONS TO ITS PRESENT TARIFF OTHER THAN THOSE REALTED TO RATE DESIGN?

A. No. The proposed changes to the present tariff reflect the proposed rate design and new rates included in the Company's filing.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

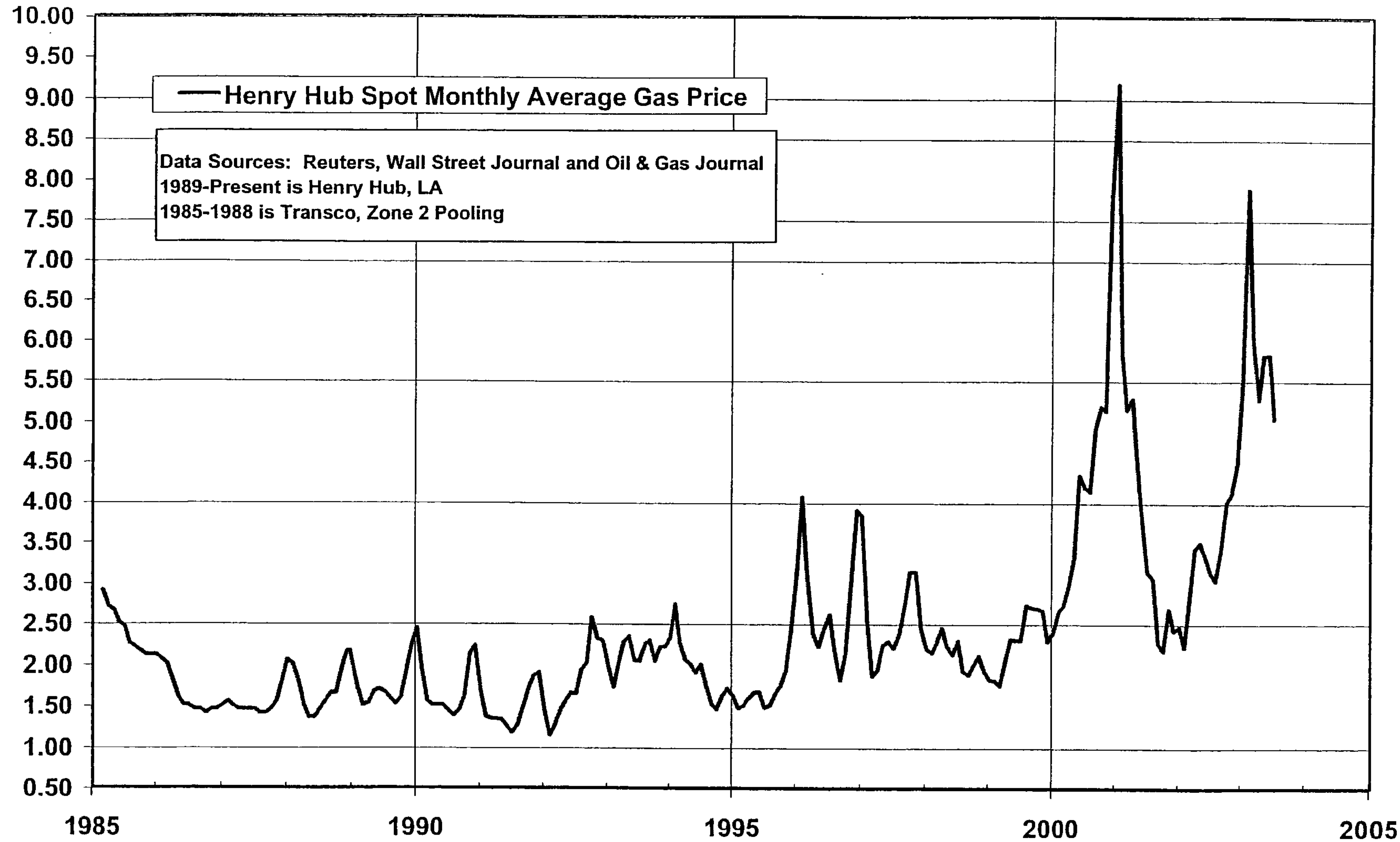
MFR SCHEDULES SPONSORED BY
BRIAN J. POWERS

SCHEDULE NO.	TITLE
A-1 p.1	EXECUTIVE SUMMARY – MAGNITUDE OF CHANGE – PRESENT vs PRIOR RATE CASE
A-2 p.1	EXECUTIVE SUMMARY – ANALYSIS OF PERMANENT RATE INCREASE REQUESTED
A-3 p. 1	EXECUTIVE SUMMARY – ANALYSIS OF JURISDICTIONAL RATE BASE
A-4 p. 1	EXECUTIVE SUMMARY – ANALYSIS OF JURISDICTIONAL NOI
A-5 p. 1	EXECUTIVE SUMMARY – OVERALL RATE OF RETURN COMPARISON
A-6 p. 1	EXECUTIVE SUMMARY – FINANCIAL INDICATORS
E-9 p. 1	COST STUDY – TARIFF SHEETS
G-1 p. 9	HISTORIC BASE YEAR + 1 – 13 MONTH AVERAGE UTILITY PLANT
G-1 p.10	PROJECTED TEST YEAR – 13 MONTH AVERAGE UTILITY PLANT
G-1 p. 11	HISTORIC BASE YEAR + 1 – DEPRECIATION RESERVE BALANCES
G-1 p. 12	PROJECTED TEST YEAR – DEPRECIATION RESERVE BALANCES
G-1 p. 13	HISTORIC BASE YEAR + 1 – AMORTIZATION RESERVE BALANCES
G-1 p. 14	PROJECTED TEST YEAR – AMORTIZATION RESERVE BALANCES
G-1 p. 15	HISTORIC BASE YEAR + 1 – ALLOCATION OF COMMON PLANT
G-1 p. 16	HISTORIC BASE YEAR + 1 – ALLOCATION OF COMMON PLANT – DETAIL
G-1 p. 17	HISTORIC BASE YEAR + 1 – ALLOCATION OF COMMON PLANT DETAIL (CONT)
G-1 p. 18	PROJECTED TEST YEAR – ALLOCATION OF COMMON PLANT
G-1 p. 19	PROJECTED TEST YEAR – ALLOCATION OF COMMON PLANT – DETAIL
G-1 p. 20	PROJECTED TEST YEAR – ALLOCATION OF COMMON PLANT – DETAIL (CONT)
G-1 p. 21	HISTORIC BASE YEAR + 1 – ALLOCATION OF DEPR / AMORT RESERVE – COMMON PLANT
G-1 p. 22	PROJECTED TEST YEAR – ALLOCATION OF DEPR / AMORT RESERVE – COMMON PLANT
G-1 p. 23	HISTORIC BASE YEAR + 1 – CONSTRUCTION BUDGET
G-1 p. 24	HISTORIC BASE YEAR + 1 – MONTHLY PLANT ADDITIONS
G-1 p. 25	HISTORIC BASE YEAR +1 – MONTHLY PLANT RETIREMENTS
G-1 p. 26	PROJECTED TEST YEAR - CONSTRUCTION BUDGET
G-1 p. 27	PROJECTED TEST YEAR – MONTHLY PLANT ADDITIONS
G-1 p. 28	PROJECTED TEST YEAR – MONTHLY PLANT RETIREMENTS
I-1 p. 1	CUSTOMER SERVICE – INTERRUPTIONS
I-2 p. 1	NOTIFICATION OF COMMISSION RULE VIOLATIONS
I-3 p. 1	METER TESTING – PERIODIC TESTING 250 cfh OR LESS
I-3 p. 2	METER TESTING – PERIODIC TESTING – 250 cfh OR LESS (CONT)
I-3 p. 3	METER TESTING – PERIODIC TESTING – 250 cfh OR LESS (CONT)
I-3 p. 4	METER TESTING – PERIODIC TESTING -251 cfh OR THROUGH 2500 cfh
I-3 p. 5	METER TESTING – PERIODIC TESTING – OVER 2500 cfh
I-4 p. 1	RECORDS – VEHICLE ALLOCATION

Exhibit____BJP-2
Docket No. 030954-GU
Indiantown Gas Compa
Page 1 of 1

INDIANTOWN GAS COMPANY

Henry Hub Spot Gas Prices ($/MMBTU)



BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY

OF MELISSA M. POWERS

ON BEHALF OF INDIANTOWN GAS COMPANY, INC

DOCKET NO. 030954-GU

DECEMBER 2003

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Melissa M. Powers. My business address is Indiantown Gas Company, Inc., P.O. Box 8, Indiantown, FL 34956.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Chief Financial Officer of Indiantown Gas Company (IGC or the Company).

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I graduated from the University of Florida in 1988 with a Bachelor of Science degree in Food and Resource Economics.

Q. PLEASE DESCRIBE YOUR WORK EXPERIENCE.

A. Upon graduation I was employed with CH2M Hill Consultants in the Groundwater Resources Department as an office assistant and technician. After relocating to Indiantown I was employed by Florida Power & Light in the Environmental Affairs Division. In 1993, upon the retirement of IGC's Financial Analyst, I was hired by Indiantown Gas Company as Office Manager to continue the functions performed by the Financial Analyst and to manage the customer service operations. In this capacity I was responsible for accounts receivable, billing, and taxes as well as preparation of financial statements. In 2000 I was promoted to Chief Financial Officer.

Q. WHAT ARE YOUR CURRENT DUTIES AS THE COMPANY'S CFO?

A. I oversee all of the Company's accounting, customer billing and regulatory reporting functions. I am also responsible for administering the Aggregated Transportation Service program and the associated interface with the Company's Pool Manger.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will support the Company's request for interim and permanent rate relief. My testimony will provide support for the Company's requested rate relief by addressing the Company's historical and projected rate base, income, and capital structure.

Q. ARE THERE ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. Yes. Exhibit No. ___ (MMP-1) is a list of MFR schedules I am sponsoring. The MFR Schedules I am sponsoring were prepared under my direction, supervision and control.

Interim Rate Increase

Q. ON WHAT HISTORICAL PERIOD IS IGC'S REQUEST FOR AN INTERIM INCREASE BASED?

A. The historical period is the 12-month period ended December 31, 2002.

Q. WHAT IS THE AMOUNT OF THE INTERIM INCREASE IGC IS REQUESTING IN THIS PROCEEDING?

A. IGC requests that annual revenues be increased by $131,896 on an interim basis. This amount represents a 38.25% increase in base rates.

Q. PLEASE DESCRIBE HOW YOU CALCULATED THIS AMOUNT?

A. The Revenue Deficiency for the interim rate increase is calculated on MFR Schedule F-7. It was derived based on an Adjusted Rate Base of $642,589 and a Requested Rate of Return of 8.49%, yielding an NOI requirement of $54,579. The Adjusted Rate Base is calculated on MFR Schedule F-1, and the Requested Rate of Return is calculated on MFR Schedule F-8. As required by Florida Statute 366.071 (5)(b)3, the Company used the bottom of the range (10.5%) of its most recent authorized return on equity (Order No. PSC-02-1666-PAA-GU) to determine the weighted cost of capital. The Company's Adjusted NOI for 2002 is ($27,273), which has been calculated on MFR Schedule F-4. An NOI Deficiency of $81,852 was determined by subtracting the Company's Adjusted NOI from the NOI Requirement. The requested interim rate increase of $131,896 equals the NOI Deficiency grossed up by the Revenue Expansion Factor (1.6114) calculated on MFR Schedule F-6.

Q. HAS THE COMPANY APPROPRIATELY REFLECTED ALL ADJUSTMENTS REQUIRED BY THE COMMISSION IN ITS LAST RATE CASE?

A. Typically, the determination of Rate Base, Rate of Return and NOI for interim rate purposes reflect adjustments made by the Commission in the Company's most recent full requirements rate case. The Company's only full requirements rate case dates back to 1970 (Order No. 4933) when the original rates for the Indiantown Gas system were established. For the purposes of this interim request, the calculations of Rate Base and Requested Rate of Return reflect adjustments to rate base to eliminate all non-utility balance sheet assets and liabilities. Adjusted NOI removes depreciation expense related to non-utility plant, adjusts for interest synchronization, and corrects state and federal tax amounts. In reconciling Capital Structure to Rate Base all adjustments occurred to equity. Total equity was established at 60% consistent with the cap set by the Commission in the Company's 2002 rate restructuring proceeding (Order No. PSC-02-1666-PAA-GU).

Q. HAS THE INTERIM REQUEST BEEN CALCULATED IN ACCORDANCE WITH THE COMMISSION'S REQUIREMENTS?

A. Yes. In my opinion, the requested interim increase is consistent with Rule 25-7.040, Florida Administrative Code, and Section 366.071, Florida Statutes, regarding interim awards.

<u>Historic Data</u>

Q. HOW DID YOU DERIVE THE HISTORIC DATA PRESENTED IN THE MFR'S?

A. All data related to the historic base year are taken from the books and records of the Company, located in Indiantown, Florida. These records are kept according to the recognized accounting practices and provisions of the Uniform System of Accounts as prescribed by the FPSC.

Rate Base

Q. PLEASE DESCRIBE HOW THE HISTORIC YEAR RATE BASE WAS CALCULATED.

A. For the historic base year, a 13-month average rate base was calculated for the period ended December 31, 2002. The historic base year also corresponds to the Company's fiscal year. MFR Schedule B-2 shows the calculation of historic base year rate base. Net plant is defined as the sum of 1) plant in service, less common plant allocated and, 2) construction work in progress (CWIP), less accumulated depreciation, and amortization. Net plant during the historic year was $564,462. An allowance for working capital, after adjustments, in the amount of $77,947, was added to net plant to calculate total rate base. As shown on MFR Schedule B-2, the total 13-month average rate base for the Company, after adjustments, was $642,589.

Q. PLEASE EXPLAIN ANY ADJUSTMENTS TO THE HISTORIC YEAR RATE BASE.

A. Net Plant was reduced by $16,411 to reflect common plant adjustments. Working Capital was reduced by $105,880 to eliminate non-utility assets and liabilities. Total adjustments to Rate Base in the historic base year are $122,291.

Q. WHAT IS THE IMPACT ON RATE BASE IN THE PROJECTED TEST YEAR OF IGC'S CAPITAL REQUIREMENTS FOR 2003 AND 2004.

A. Projected capital spending is detailed on Schedule G-1, and amounts to $39,755 for the historic base year +1 (page 23) and $222,123 (page 26) in the projected test year. These expenditures have been scheduled by month in accordance with IGC's expectations as to the timing of the actual outlays. Average Rate Base is calculated reflecting the timing of the expenditures and their impact on CWIP and plant balances.

Q. WHAT IS THE APPROPRIATE PROJECTED TEST YEAR UTILTIY PLANT IN SERVICE FOR IGC?

A. The appropriate Utility Plant in Service is $1,316,581, reflecting the adjustments described above, MFR Schedule G-1, page 1.

Q. PLEASE EXPLAIN ANY ADJUSTMENTS TO THE PROJECTED TEST YEAR RATE BASE.

A. Net Plant was reduced by $16,765 to reflect common plant adjustments. Working Capital was reduced by $154,532 to eliminate non-utility assets and liabilities. Total adjustments to Rate Base in the historic base year are $171,296.

Q. WHAT ARE THE APPROPRIATE DEPRECIATION RATES FOR THE HISTORIC BASE YEAR AND THE PROJECTED TEST YEAR?

A. The Company used the depreciation rates approved for IGC by the Commission on January 5, 1999 (Order PSC-99-0048-FOF-GU) for the historic base year. On October 6, 2003, the Company's present depreciation rates were approved by the Commission (Order No. PSC-03-1111-PAA-GU). The recently approved rates have been implemented by the Company, and are used in the projected test year computations..

Q. HAS IGC IDENTIFIED AND EXCLUDED FROM RATE BASE THOSE PORTIONS OF ITS COMMON PLANT THAT ARE PROPERLY ALLOCATED TO NON-UTILITY OPERATIONS?

A. Yes. The utility thoroughly reviewed its common plant assets. Adjustments were made to common plant and accumulated depreciation in Rate Base and depreciation expense. These adjustments are reflected on pages 15 through 22 of MFR Schedule G-1 for the historic base year +1, and for the projected test year. Common Plant allocations for all periods. were based on the ratio of regulated net utility plant investment to non-regulated net plant investment in the historic base year. During the historic base year utility net plant was recorded at $581,053 and non-utility net plant was $38,354, producing a non-utility allocation percentage of 6.2%.

Q. HAS THE COMPANY EXCLUDED COMPONENTS OF WORKING CAPITAL APPLICABLE TO NON-UTILTIY OPERATIONS FROM THE WORKING CAPITAL ALLOWANCE?

A. Yes. Any specific assets and liabilities related to non-utility operations remaining on IGC's books were removed from working capital by adjustment. In addition, provision has been made to exclude from working capital the appropriate portion of common current assets and liabilities apportionable to non-utility activities. The basis for the allocation was the ratio of utility plant to non-utility plant discussed above. The share of total IGC costs applicable to its non-utility operations was 6.2%.

Q. WHAT IS THE APPROPRIATE WORKING CAPITAL ALLOWANCE FOR THE PROJECTED TEST YEAR?

A. The appropriate Working Capital Allowance, calculated using the Balance Sheet Method, is ($154,532) per Schedule G1 page 3, which reflects the adjustments described above.

Q. WHAT IS THE APPROPRIATE ADJUSTED RATE BASE FOR THE PROJECTED TEST YEAR?

A The appropriate Adjusted Rate Base for the projected test year is $755,812. MFR Schedule G-1, page 1 presents the components of the IGC Rate Base.

Net Operating Income

Q. WHAT IS THE APPROPRIATE AMOUNT OF OPERATING REVENUES FOR THE PROJECTED TEST YEAR?

A. The appropriate amount of Operating Revenues for the projected test year is $342,918.

Q. WHAT ADJUSTMENTS WERE MADE TO PROPERLY REFLECT OPERATING REVENUES FOR THE PROJECTED TEST YEAR?

A. No adjustments were made to operating revenues for the projected test year.

Q. WHAT IS THE APPROPRIATE O&M BENCHMARK VARIANCE FACTOR FOR IGC?

A. The appropriate benchmark variance factor is 1.0598, reflecting the increase in the average number of customers and the increase in the average Consumer Price Index ("CPI") from 1999 to the current case historic base year (2002). The calculation of this benchmark variance factor is presented on Schedule C-37.

Q. PLEASE DISCUSS THE BENCHMARK VARIANCES FOR OPERATIONS & MAINTENANCE EXPENSE AS SHOWN ON MFR SCHEDULE C-34.

A. Although certain individual operating and maintenance accounts have grown at a rate faster than the benchmark would predict, overall costs are about 28% below the benchmark projections from 1999 to the present. The two areas, Sales Expense and Distribution Maintenance, which appear to be above the benchmark exist simply because of cost re-allocations from Administration & General and Distribution Operations respectively. The total variance for O & M Expenses is a favorable variance of $124,440. This total favorable variance includes individual favorable variances of $12,227 for Distribution Operations, $19,820 for

Customer Accounts and $98,090 for Administration & General. The unfavorable variances of $3,352 for Distribution Maintenance and $2,344 for Sales Expenses were described above. .

Q. PLEASE EXPLAIN THE SOURCE OF DATA FOR THE O & M COMPOUND MULTIPLIER CALCULATION ON MFR SCHEDULE C-37.

A. Company records were used to determine the number of customers at year-end. From year-end 1999 year-end 2002 the number of customers decreased by one (1) customer. The CPI annual average data was obtained from the Annual and Monthly Report from the US Bureau of Labor Statistics. The CPI increased from 166.6 for 1999 to 179.9 for 2002, for an increase of 6.4%.

Q. PLEASE EXPLAIN THE TRENDING FACTORS ON MFR SCHEDULE G-2, PAGE 10. AND DESCRIBE ANY ADJUSTMENTS YOU MADE FOR KNOWN CHANGES.

A. The trending was done in two parts. All O&M expenses were divided between labor and other expenses. An appropriate factor was calculated or otherwise determined for each group of expenses. This factor was then compounded for a two-year period (2003 and 2004) and applied to the 2002 expenses in each functional area to derive the projected test year amounts.

Annual increases of 2.5% and 5% were used to trend labor expenses in 2003 and 2004, respectively. Non-labor expenses were trended using an either: 1) a compounded inflation rate of 4.06%, which was calculated using the projected increases in the CPI of 2.5% for both 2003 and 2004 or, 2) a compounded customer growth times inflation rate of 6.64%.

Q. COULD YOU DESCRIBE THE MAJOR EXPENSES THAT WERE DETERMINED BY SOME METHOD OTHER THAN TRENDING 2002 EXPENSES?

A. O&M expenses that were developed by specific examination of the expected costs in 2004 rather than by trending 2002 expenses are discussed in detail in Brian Powers' testimony.

Q. WHAT IS THE APPROPRIATE AMOUNT OF RATE CASE EXPENSE AND THE APPROPRIATE AMORTIZATION PERIOD?

A. The Company's calculation of rate case expense for the current case is included on Schedule C-13. The total projected costs amount to $100,050. It should be noted, however, that this projection will change in the event a hearing is required to resolve this case. We propose that the amount projected for this case is amortized over a four-year period. The total amount projected for rate case amortization expense in 2004 is $25,013.

Q. HAS IGC PROPERLY IDENTIFIED AND EXCLUDED FROM O&M THOSE PORTIONS OF ITS A&G EXPENSES THAT ARE APPLICABLE TO ITS NON-UTILITY OPERATIONS?

A. The Company has no O&M adjustments.

Q. WHAT IS THE APPROPRIATE AMOUNT OF PROJECTED TEST YEAR O&M EXPENSE?

A. The appropriate amount of O&M for the Projected Test year is $447,301, which is included in Operating Expenses used to calculate Net Operating Income on Schedule G-2, page 1.

Q. WHAT IS THE APPROPRIATE AMOUNT OF DEPRECIATION EXPENSE TO BE INCLUDED IN THE PROJECTED TEST YEAR?

A. The appropriate amount of depreciation expense is $68,248, after eliminating common plant, which is included on Schedule G-2, page 25.

Q. WHAT IS THE APPROPRIATE AMOUNT OF TAXES OTHER THAN INCOME TAXES TO BE INCLUDED IN THE PROJECTED TEST YEAR?

A. The appropriate amount of taxes other than income taxes is $24,924, which is included in Operating Expenses on Schedule G-2, page 1.

Q. WHAT IS THE APPROPRIATE AMOUNT OF INCOME TAX EXPENSE FOR THE PROJECTED TEST YEAR, INCLUDING INTEREST SYNCHRONIZATION?

A. The appropriate amount of Income Tax Expense, including an adjustment for interest synchronization, for the projected test year is ($83,451), which is presented by component on Schedule G-2, page 1.

Q. WHAT IS THE APPROPRIATE AMOUNT OF NOI FOR THE PROJECTED TEST YEAR?

A. The appropriate amount of NOI for the projected test year, as adjusted for the items described above, is ($114,103) as identified on MFR Schedule G-2, page 1.

Capital Structure

Q. HAVE YOU PREPARED AN EXHIBIT SHOWING THE COMPANY'S CAPITAL STRUCTURE?

A. Yes. The information appears on Schedule G-3, page 2.

Q. HAVE YOU PREPARED THE COMPANY'S CAPITAL STRUCTURE FOR RATEMAKING PURPOSES CONSISTENT WITH THE MANNER IN WHICH IT WAS APPROVED IN THE LAST RATE CASE?

A. No. The Company's last rate case was in 1970, when the original system rates were approved. The most recent Commission action related to the IGC's capital structure was during the Company's 2002 rate restructuring (Order PSC-02-1666-PAA-GU). During this proceeding the Commission ordered that equity be imputed at 60%. The Company followed this directive in preparing the capital structure for this case.

Q. WHAT DEBT/EQUITY RATIO AFTER ADJUSTMENTS DID YOU EMPLOY?

A. The calculation of capital structure reflects sources of capital as follows: Equity 59.93 %, Long-Term Debt 37.80 %, and Customer Deposits 2.27%. The Company is projecting no Short-Term Debt.

Q. ON WHAT IS THE AMOUNT OF EQUITY BASED?

A. The amount of equity is based on the projected weighted average balance of common equity for the projected test year, reduced by the amount invested in the non-utility operations of the Company. The Company is proposing to make a pro-rata adjustment to increase equity and decrease long-term debt in the projected test year capital structure to more appropriately reflect historical debt/equity ratios during periods where the Company is not under unprecedented financial duress. The dramatic reduction in margin revenue primarily resulting from the decline in sales volume to the cogeneration plant (discussed in both Brian Powers and Jeff Householder's testimony) has a significant negative affect on retained earnings in the projected test year at present rates. Under these unusual conditions equity unavoidably decreases and, absent rate relief, the Company projects that it would be required to continue financing the operations of the Company with new debt. In the Company's view it is appropriate, for ratemaking purposes, to adjust equity to a more reasonable level. The capital structure has been adjusted to reflect the 60% equity, 40% debt ratio imputed by the Commission for earnings surveillance purposes when it established the Company's current ROE in 2002 (Order No. PSC-02-1666-PAA-GU). The Company's objective is to achieve and maintain a ratio consistent with the Commission Order. It is my belief that such a debt/equity ratio is reflective of the actual capital structure that will exist during the period rates are in effect.

Q. WHAT IS THE APPROPRIATE LEVEL OF CUSTOMER DEPOSITS TO BE USED IN THE DETERMINATION OF IGC'S CAPITAL STRUCTURE FOR THE PROJECTED TEXT YEAR?

A. The appropriate level of Customer Deposits to be included in the determination of IGC's capital structure is $17,164, which is the average level of customer deposits for the projected test year.

Q. WHAT IS THE APPROPRIATE LEVEL OF DEFERRED INVESTMENT TAX CREDITS TO BE USED IN THE DETERMINATION OF IGC'S CAPITAL STRUCTURE FOR THE PROJECTED TEST YEAR?

A. The Company has no Deferred Investment Tax Credits.

Q. WHAT IS THE APPROPRIATE LEVEL OF DEFERRED INCOME TAXES TO BE USED IN THE DETERMINATION OF CITY GAS' CAPITAL STRUCTURE FOR THE PROJECTED TEST YEAR?

A. The Company has projected no Deferred Income Taxes for the projected test year.

Q. DOES IGC'S CAPITAL STRUCTURE FOR RATEMAKING PURPOSES FOR THE PROJECTED TEST YEAR PROPERLY EXCLUDE NON-UTILITY INVESTMENTS?

A. Yes. All investments of the Company's propane or other non-utility activities have been excluded from the proposed capital structure through an adjustment to the equity portion of the capital structure..

Q. WHAT IS THE APPROPRIATE COST RATE FOR COMMON EQUITY?

A. The appropriate cost rate for Common Equity is 11.5%, as described by Brian Powers in his testimony.

Q. WHAT IS THE APPROPRIATE COST RATE FOR LONG-TERM DEBT?

A. The appropriate cost rate for Long-Term Debt is 8.10%.

Q. WHAT IS THE APPROPRIATE COST RATE FOR SHORT-TERM DEBT?

A. The Company projects no Short-Term Debt in the projected test year..

Q. WHAT IS THE APPROPRIATE COST RATE FOR CUSTOMER DEPOSITS?

A. The appropriate cost rate for Customer Deposits is 6.22%. This is a weighted average rate of 6% paid by IGC on residential customer deposits and 7% on commercial deposits in accordance with IGC's tariff.

Q. WHAT IS THE APPROPRIATE COST RATE FOR INVESTMENT TAX CREDITS AND DEFERRED INCOME TAXES?

A. As noted above, IGC has no Deferred Investment Tax Credits or Deferred Income Taxes.

Q. WHAT IS THE APPROPRIATE WEIGHTED AVERAGE COST OF CAPITAL FOR IGC FOR RATEMAKING PURPOSES FOR THE PROJECTED TEST YEAR?

A. IGC's appropriate weighted average overall cost of capital for the projected test year is 10.09%.

Q. WHAT IS THE APPROPRIATE REVENUE EXPANSION FACTOR FOR THE PROJECTED TEST YEAR?

A. The appropriate revenue expansion factor is 1.6114, as calculated on Schedule G-4.

Q. WHAT ARE THE REVENUE DEFICIENCY AND TOTAL OPERATING REVENUE REQUIREMENT FOR THE PROJECTED TEST YEAR?

A. The revenue deficiency for IGC for the projected test year is $306,751, as calculated on Schedule G-5 of the MFRs, representing an 89.45% increase. This deficiency results from a total operating revenue requirement of $649,675, which has been used as the basis for the rates developed by company witness Jeff Householder, as presented in his testimony. The requested increase is required by the Company in order to give it the opportunity to earn a fair rate of return based on conditions during the projected test year.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MFR SCHEDULES SPONSORED BY
Melissa M. Powers

SCHEDULE NO.	TITLE
B-1 p.1	13 MONTH AVERAGE BALANCE SHEET – ASSETS
B-2 p.2	13 MONTH AVERAGE BALANCE SHEET – LIABILITIES & CAPITALIZATION
B-2 p.1	RATE BASE – 13 MONTH AVERAGE
B-3 p.1	RATE BASE ADJUSTMENTS
B-4 p.1	MONTHLY PLANT BALANCES TEST YEAR – 13 MONTHS
B-5 p.1	ALLOCATION OF COMMON PLANT
B-5 p.2	DETAIL OF COMMON PLANT
B-5 p.3	DETAIL OF COMMON PLANT (CONT)
B-6 p.1	ACQUISITION ADJUSTMENT
B-7 p.1	PROPERTY HELD FOR FUTURE USE – 13 MONTH AVERAGE
B-7 p.2	PROPERTY HELD FOR FUTURE USE DETAILS
B-8 p.1	CONSTRUCTION WORK IN PROGRESS
B-9 p.1	DEPRECIATION RESERVE BALANCES
B-10 p.1	AMORTIZATION / RECOVERY RESERVE BALANCES
B-11 p.1	ALLOCATION OF DEPRECIATION / AMORTIZATION RESERVE – COMMON PLANT
B-12 p.1	CUSTOMER ADVANCES FOR CONSTRUCTION
B-13 p.1	WORKING CAPITAL – ASSETS
B-13 p.2	WORKING CAPITAL – LIABILITIES
B-14 p.1	DETAIL OF MISCELLANEOUS DEBITS
B-15 p.1	DETAIL OF OTHER DEFERRED CREDITS
B-16 p.1	ADDITIONAL RATE BASE COMPONENTS
B-17 p.1	INVESTMENT TAX CREDITS – ANALYSIS
B-17 p.2	INVESTMENT TAX CREDITS – ANALYSIS (CONT)
B-17 p.3	INVESTMENT TAX CREDITS – COMPANY POLICIES
B-17 p.4	INVESTMENT TAX CREDITS – SECTION 46(f) ELECTION
B-18 p.1	ACCUMULATED DEFERRED INCOME TAXES – SUMMARY
B-18 p.2	ACCUMULATED DEFERRED INCOME TAXES – STATE
B-18 p.3	ACCUMULATED DEFERRED INCOME TAXES – FEDERAL
C-1 p.1	NET OPERATING INCOME
C-2 p.1	NET OPERATING INCOME ADJUSTMENTS
C-2 p.2	NET OPERATING INCOME ADJUSTMENTS (CONT)
C-3 p.1	OPERATING REVENUES BY MONTH
C-4 p.1	UNBILLED REVENUES
C-5 p.1	OPERATION & MAINTENANCE EXPENSES
C-5 p.2	OPERATION & MAINTENANCE EXPENSES (CONT)
C-6 p.1	ALLOCATION OF EXPENSES
C-7 p.1	CONSERVATION REVENUES AND EXPENSES
C-8 p.1	UNCOLLECTIBLE ACCOUNTS
C-8 p.2	UNCOLLECTIBLE ACCOUNTS (CONT)
C-9 p.1	ADVERTISING EXPENSES
C-9 p.2	ADVERTISING EXPENSES (CONT)
C-10 p.1	CIVIC AND CHARITABLE CONTRIBUTIONS
C-11 p.1	INDUSTRY ASSOCIATION DUES

MFR SCHEDULES SPONSORED BY
Melissa M. Powers

SCHEDULE NO.	TITLE
C-12 p.1	LOBBYING AND OTHER POLITICAL EXPENSES
C-13 p.1	TOTAL RATE CASE EXPENSE AND COMPARISONS
C-14 p.1	MISCELLANEOUS GENERAL EXPENSES
C-15 p.1	OUT OF PERIOD ADJUSTMENTS TO REVENUES AND EXPENSES
C-16 p.1	GAINS AND LOSSES ON DISPOSITION OF PLANT OR PROPERTY
C-17 p.1	MONTHLY DEPRECIATION EXPENSE FOR THE HISTORIC BASE YEAR – 12 MONTH
C-18 p.1	AMORTIZATION / RECOVERY SCHEDULE FOR HISTORIC BASE YEAR – 12 MONTH
C-19 p.1	ALLOCATION OF DEPRECIATION / AMORTIZATION EXPENSE – COMMON PLANT
C-20 p.1	RECONCILIATION OF TOTAL INCOME TAX PROVISION
C-21 p.1	STATE AND FEDERAL INCOME TAX CALCULATION – CURRENT
C-22 p.1	INTEREST IN TAX EXPENSE CALCULATION
C-23 p.1	BOOK / TAX DIFFERENCES – PERMANENT
C-24 p.1	DEFERRED INCOME TAX EXPENSE
C-25 p.1	DEFERRED TAX ADJUSTMENT
C-25 p.2	DEFERRED TAX ADJUSTMENT (CONT)
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MFR SCHEDULES SPONSORED BY
Melissa M. Powers

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MFR SCHEDULES SPONSORED BY
Melissa M. Powers

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFF HOUSEHOLDER

ON BEHALF OF INDIANTOWN GAS COMPANY

DOCKET NO. 030954-GU

DECEMBER, 2003

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

A. My name is Jeff Householder. I provide energy consulting and business development services to natural gas utilities, natural gas marketers, propane gas retailers, government agencies, and a number of industrial and commercial clients. I have participated in a variety of cases before the Florida Commission including several general rate proceedings. My business address is 2333 West 33rd Street, Panama City, Florida, 32405.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. Prior to beginning my consulting business in January 2000, I was Vice President of Marketing and Sales for TECO Peoples Gas from 1997 to 1999. While with TECO, I was also responsible for the management of TECO Gas Services, an unregulated energy marketing company. I joined Peoples Gas subsequent to the 1997 TECO Energy acquisition of West Florida Natural Gas Company. At West Florida Natural Gas, I served as Vice President of Regulatory Affairs and Gas Management from 1995 to the TECO merger. Before that, in 1994-1995, I was Vice President of Marketing and Sales at City Gas Company, a division of the NUI Corporation. Prior to joining City Gas, I was employed as Utility Administrative Officer for the City of Tallahassee. During my ten years (1984-1994) with the City's utility operations, I also held positions as Assistant Director of the Consumer Services Division and managed the Energy Services Department, a marketing and demand-side management unit. From 1981 to 1984, I was a Section Manager with the Florida Department of Community Affairs, responsible for administering the Florida Energy Code and related construction industry regulatory standards. I also served from 1980 to 1981 as an Energy Analyst in the Governor's Energy Office. From 1984 to 1995, concurrent with my other positions, I provided part-time consulting services to the natural gas, propane gas and homebuilding industries involving a variety of building code, marketing and energy regulatory matters. I am a 1978 graduate of Florida State University with a Bachelor of Science Degree majoring in Economics and Government.

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

A. I will describe the methodology used to forecast sales, customers and revenues for the Historic Base Year + 1 and the Projected Test Year. I will also sponsor the Company's proposed interim and permanent rate design. In support of my permanent rate design testimony, I have prepared a cost of service study by customer class for the Projected Test Year ended December 31, 2004. In addition, I have reviewed competitive energy alternatives for each customer class. I will describe how the results of both the cost of service study and the competitive analysis were used in designing the Company's proposed rates.

Q. ARE YOU SPONSORING ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. Exhibit No. ___ (JMH-1) is a list of MFR schedules I am sponsoring. Exhibit ___ (JMH-2) displays the interim rate increase allocation among current customer classifications. Exhibit No. ___ (JMH-3) is an analysis of competitive fuel costs in the Company's service areas. Exhibit No. ___ (JMH-4) is a comparison of present and proposed rates by rate classification. The referenced MFR Schedules and exhibits were prepared under my direction, supervision and control.

Sales, Customer and Revenue Forecast

Q. HAS THE COMPANY PREPARED A FORECAST OF SALES, CUSTOMERS AND REVENUES FOR THE BASE YEAR + 1 AND PROJECTED TEST YEAR?

A. Yes. I prepared, on the Company's behalf, a forecast of sales, customers and revenue by customer classification, for the Base Year +1 and the Projected Test Year. The results of this forecast are displayed on MFR Schedule G-2, pp. 6-9. The forecasts of revenues for both the Base Year + 1 and the Projected Test Year were computed using net customer and sales growth (loss) and the Company's existing rates. As detailed on page 8 of MFR Schedule G-2, the total Projected Test Year revenues at current rates, are projected to be $342,918 inclusive of other revenues for the same period projected, at current rates, to total $4,120. The revenue requirement deficiency addressed in this case was established based on the above forecast result.

Q. DOES THE COMPANY'S CUSTOMER, SALES AND REVENUE FORECAST ACCOUNT FOR PROPOSED REVISIONS TO ITS EXISTING CUSTOMER CLASSIFICATIONS?

A. Yes. The forecasts of customers, sales and revenues presented in the MFRs filed in this rate proceeding are consistent with the Company's proposed customer classifications and rate schedules. The proposed classes are described in detail later in my testimony. The Company's historical customer, sales and revenue data was sorted based on the proposed customer classifications. This historical data formed a base-line for the Company's projections.

Q. PLEASE DESCRIBE THE CUSTOMER AND SALES FORECASTING PROCESS USED IN THIS FILING.

A. Indiantown Gas is a company with close ties to the small communities it serves. Company representatives, through their social and civic activities, are well informed about opportunities to expand the system or increase load, as well as potential customer or load loss situations. The Company President is a member of the local Community Redevelopment

Area Council, and routinely attends County Commission meetings. Any proposed development project would be known well in advance of construction. Through its active community involvement, the Company is continually assessing the opportunities and risks of the local market.

This assessment involves several on-going activities. They include customer interviews, discussions with potential residential and commercial developers, discussions with building industry contractors currently operating in Martin County, direct involvement in local Economic Development Councils and Chambers of Commerce, and a variety of contacts with Building Officials, Planning Boards and other agencies with knowledge of potential future development. Given the small number of total customers served by Indiantown, it was feasible to individually review each non-residential customer to prepare specific forecast information, and we did so.

Data from the Company's local market assessment, along with several years of historical information on customer additions and therm usage were used to prepare the forecast for this case. A forecast of customer growth and loss has been prepared for each customer class. Transportation volumes were projected by class for both existing and new customer additions. Average transportation volumes for the proposed TS-1 and TS-2 classes (residential and small commercial customers under 15,000 annual therms) were calculated from historical data and used in the forecasts to trend existing accounts. Consumption for the limited number of new customer additions projected for these classes (ten (10) new residences in 2004) was also projected based on historical averages. Weather effects for residential and small commercial customers were considered in the volume forecasts through the averaging of consumption over a five-year period. Volume changes for existing customers and conversions of existing residences or businesses from electricity or propane were assessed. There are no projected customer conversions and no known sales volume changes for the small usage classes projected for 2004, or beyond. The large commercial account (Entegra Tile) in the TS-3 class and the two large volume industrial accounts in the TS-4 class (Indiantown Cogeneration, L.P. and Louis Dreyfus Citrus) were forecast individually, based on conversations with these customers and historical data. The customer and sales forecasts were used to derive projected revenues from sales for each customer class.

Q. PLEASE DESCRIBE HOW YOU DEVELOPED THE NUMBER OF CUSTOMERS BILLED IN EACH CLASS FOR THE BASE YEAR + 1 AND THE PROJECTED TEST YEAR.

A. The first step in developing the customer growth forecast was a determination of the actual number of customers in the Company's existing customer classes billed in December 2002. Next, I evaluated the net customer additions that had occurred during 2003. The Company's CIS produced reports of actual customers by class through October

2003. The residential customer group experienced normal disconnect-reconnect activity in 2003 primarily due to account changes at existing residences. The Company reported no permanent loss of residential customers through October 2003. There was also no permanent change in the number of commercial or industrial customers during the year. The actual October 2003 customers formed the base upon which the customer projections were forecast.

I next interviewed Company employees, local officials, builders and others knowledgeable of local market conditions. The information gathered from these discussions was used in compiling the customer additions forecast for the remainder of the Base Year +1 and the Projected Test Year. Potential customer loss by class was also projected based on historical data and discussions with Company employees to derive net customer growth.

The Company has maintained historical records of customers by type and by month for several years. I used the 1998 through October 2003 customer and sales data to develop an average of active customers per month. This data was sorted based on the Company's proposed customer classes. There has been insignificant net customer growth in residential accounts over the past five years. The data reflected a pattern for residential customers that account for seasonal customers. This pattern was continued in the forecast for November and December 2003 and the Projected Test Year. The Company is forecasting to add ten (10) new residential services in 2004 and lose zero (0).

The number of commercial customers has also not significantly changed over the past few years. There is virtually no discernable, consistent seasonal customer gain or loss pattern represented in the commercial customer data. Based on discussions with the Company's customer service representatives, and a review of CIS records, the commercial additions and losses over the past several years have been essentially equal. The Company is not forecasting a net customer increase in commercial accounts in the Projected Test Year. The number of active commercial customers in October 2003 was continued throughout 2004. No large volume industrial customer additions are expected in the Projected Test Year.

Q. DOES THE FORECAST ACCOUNT FOR ANY RECLASSIFACTION OF EXISTING CUSTOMERS TO A NEW VOLUMETRIC CLASS IN THE PROJECTED TEST YEAR?

A. Yes. The forecast assumes that the Company will reassign six (6) commercial customers current receiving service in the TS-2 class to the TS-1 class in January 2004. The forecast also assumes that Indiantown Cogeneration will receive service in the TS-4 class in 2004. The cogeneration plant received service under a special contract rate until November 2003. At that time they transferred into the TS-4 class, under the terms of a revised special contract approved by the Commission

(Order No. PSC-03-1156-PAA-GU). The Company's Projected Test Year forecast appropriately accounts for the above customer migration.

Q. HOW WERE THE THERM SALES PROJECTIONS DEVELOPED?

A. Historical consumption data for each of the Company's customers was obtained and used to develop monthly consumption estimates for each proposed customer class. An average monthly consumption amount for the TS-1 and TS-2 classes was developed using the actual monthly consumption totals for the period 1998 through October 2003. The monthly consumption averages by class were divided by actual monthly active customers over the same period, resulting in average monthly therms per customer. This computational method accounts for weather variability and seasonal customer fluctuations. The Company's interviews with non-residential customers identified no plans that would require a substantial adjustment to the historic consumption averages.

The customer forecast described above provided the number of customers billed each month during the Base Year + 1 and the Projected Test Year for the TS-1 and TS-2 classes. Annual therm sales for these respective customer classes were estimated by multiplying the projected number of customers billed each month by the estimated usage per customer for the month, totaled for the year.

The three remaining industrial customers Entegra Tile, Louis Dreyfus Citrus and Indiantown Cogeneration were forecast individually based on conversations with the customers and an assessment of historic usage. Entegra Tile is the only customer forecast for class TS-3. Louis Dreyfus and Indiantown Cogeneration are both projected as TS-4 customers, due to the significant reduction in sales volume at the cogeneration facility. No customers will qualify for the TS-5 volumetric threshold in 2004, or in the foreseeable future. The TS-5 rate class is proposed for deletion.

Q. HOW DID THE COMPANY ESTIMATE REVENUES FOR THE BASE YEAR + 1 AND THE PROJECTED TEST YEAR?

A. Revenue projections displayed on MFR Schedule G-2 were prepared by applying the forecasts of customers and sales volumes described above for the respective periods using both the Company's current and proposed rate structures.

<u>Interim Increase</u>

Q. PLEASE DESCRIBE THE METHOD USED TO PROPOSE INTERIM RATE RELIEF.

A. The Company followed the methodology provided in MFR Schedule F for calculating and allocating appropriate interim rates.

Q. WHAT IS THE REVENUE INCREASE THE COMPANY IS REQUESTING FROM INTERIM RATES?

A. The Company requests that annual revenues be increased by $131,896.

Q. HOW WAS THE INTERIM RATE INCREASE ALLOCATED AMONG CUSTOMER CLASSES?

A. The revenue deficiency calculated on MFR Schedule F-7 was allocated on an equal percentage basis (38.25%) to each of the Company's existing customer classifications. The transportation charge for each respective class has been adjusted to achieve the proposed interim increase. Exhibit No. ___ (JMH-2), which is a summary of MFR Schedule F-10, presents the allocation of the Company's requested interim rate relief.

Cost of Service and Rate Design

Q. PLEASE DESCRIBE THE PROCESS USED TO DESIGN THE PROPOSED PERMANENT RATES.

A. I performed a fully embedded cost-of-service study to determine the appropriate assignment of expense and investment costs to each of the Company's classes of service. The cost study utilized information from all areas of the Company's operations, including customer billing and consumption records, engineering studies, forecasts of growth, and cost data from the accounting records. The total cost of service was assigned or allocated to determine the revenue requirements of each class of customers. The results of my analysis provided the principal basis for the Company's proposed rate design, which is detailed on MFR schedule H-1, and is summarized on Exhibit No. ___ (JMH-4).

Q. WAS A PARTICULAR METHODOLOGY OR MODEL USED TO PREPARE THE COST OF SERVICE STUDY?

A. Yes. The standard methodology traditionally used by Commission Staff formed the principal basis of the cost of service study. The Company's study also follows the presentation format contained in the H Schedules of the prescribed MFR forms.

Q. YOU NOTED ABOVE THAT THE COST STUDY PROVIDES "THE PRINCIPAL BASIS" FOR DESIGNING RATES. WERE OTHER FACTORS USED TO ESTABLISH THE PROPOSED RATES?

A. Yes. As described in more detail later in the testimony, there are three specific adjustments that were made to the initial cost allocations produced by the Commission Staff's model. First, I adjusted the final rates in several of the classifications to address alternate fuel market competition. Each of the market-based rate adjustments was accomplished through a reallocation of cost in the Direct and Special Cost section of the Commission Staff's cost model, MFR Schedule H-2. Second, I included a direct allocation of costs to the proposed Third Party Supplier customer class. Third, the cost study model is not designed to allocate cost to a Demand Charge rate component. In designing the proposed Demand Charge for the TS-3 and TS-4 classes, I allocated a portion of both capacity and customer costs assigned by the model to establish a fixed demand rate for the recovery of these costs.

Q. PLEASE DESCRIBE THE OBJECTIVES IN PERFORMING A COST OF SERVICE STUDY.

A. There are two primary objectives in cost of service analysis. The first objective is the development of "unbundled" cost information by function (production, storage, transmission and distribution) and classification (customer, commodity, demand and revenue) in order that cost based rates may be designed for each customer service classification. The second objective is the determination of the rate of return for each of the Indiantown Gas customer service classifications based on present rates. Such information will provide guidance in equitably allocating the Company's proposed revenue increase.

Q. HOW IS A COST OF SERVICE STUDY PERFORMED?

A. Traditional cost studies can be segmented into three individual activities: functionalization, classification and allocation.

Functionalization refers to the process of relating plant investments and associated operating expenses to four basic functional categories. The functional categories are production, storage, transmission and distribution. Plant investments and related operation, maintenance, depreciation and tax expenses are assigned to the functional categories. The functional assignment of costs is a relatively straightforward process. The Company maintains its accounting records in accordance with the FERC Uniform System of Accounts. FERC accounting assigns plant facilities and investments to cost of service functions. Related expenses follow the same functionalization.

Classification refers to the process of dividing the functional costs into categories based on cost causation. Each local distribution system is designed and operated based on the individual and collective service requirements of its customers. The cost of providing such service is categorized in order to assign costs to the customer classes that are principally responsible for those costs. Typically, there are four categories used to group costs: capacity or demand costs, commodity costs, customer costs and revenue costs. Rate base and the overall cost of service are classified on MFR Schedule H-1.

1. Capacity or demand costs are those costs incurred by the utility to meet the on-demand service requirements of the total customer base. Capacity costs are related to the peak or maximum demand requirements placed on the system by its customers. Capacity costs are incurred to ensure that the system is ready to serve customers at peak requirements levels. These costs are generally considered to be "fixed", and are incurred whether or not a customer uses any gas.

2. Commodity costs are variable and relate to the quantitative units of product consumed. Costs which can be linked to the volume of gas sold or transported fit into this category.

3. Customer costs are those costs incurred to connect a customer to the distribution system, meter their usage and maintain their

account. In addition, other costs such as meter reading, which are a function of the number of customers served, should be included in this category. Customer costs continue to be incurred without regard to a customer's level of consumption.

4. Revenue costs are related to those costs items which can be assigned based on the percentage of total revenue received from each class of customer. These costs vary with the amount of sales revenue collected by the Company. Gross receipts taxes and regulatory assessment fees fall into this category.

I have utilized the cost classification methodology contained in the MFR model. The "classifiers" identified in the model were not altered. The classification of each functionalized cost component is contained in MFR schedule H-1, pages 2-5.

Allocation involves the distribution or assignment of the classified costs to the Company's service classes. Those costs which can be directly attributable to a specific customer or class of customers are assigned to that customer or class. The remaining costs are assigned by applying a series of allocation factors. The allocation factors attempt to distribute costs based on the causal relationships between the respective customer classes and the classified costs. The development and application of the allocation factors and direct assignment of costs is the final step in a cost of service study. MFR Schedule H-2, page 5, details the development of allocation factors by class of service.

Q. YOU INDICATED THAT COSTS WERE ALLOCATED BY SERVICE CLASS. PLEASE DESCRIBE HOW CLASSES OF SERVICE ARE ESTABLISHED.

A. Customers of a utility are usually grouped into relatively homogeneous classes according to their service characteristics. Consumption levels, pressure requirements, load factors, conditions under which service is provided (curtailment status, for example), and end-use application of the fuel can be considered when establishing service classes. Traditionally, LDC's have established classes based on customer type (residential, commercial, industrial) and/or annual volumetric therm consumption ranges. Other class distinctions, firm vs. interruptible and sales vs. transportation, for example, are also common.

Typically, the utility can identify a different level of cost to provide service to each discrete service class. Distinctions between classes established by customer type or volume have generally been based on the discernable cost differences from one class to another or the presence of market conditions that dictate the classification. Several cost breakpoints can be identified which can generally be linked to annual volumetric requirements. Meter and regulator type and size, service line size, and on-going maintenance costs are among the cost items that distinguish one service class from another. Another important factor that may be considered in classifying customers is the impact of a customer or class of customers on the Company's local distribution capacity. The facility related costs to serve are a function of peak hour load requirements not annual transportation volumes. System demand considerations are critical in assessing the overall cost of providing service to the respective service classes. However, most LDC's have elected to group customers by annual volume rather than a peak hour or other demand requirement.

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT SERVICE CLASSIFICATIONS.

A. The Company's current service classifications were established in its 2002 Rate Restructuring proceeding (Order No. PSC-02-1666-PAA-GU). The Commission approved the elimination of the traditional residential, commercial, industrial customer classes in favor of classes based on annual volumetric consumption levels, regardless of customer type. In addition, designations of firm and interruptible character of service were eliminated. The customer classes were stratified based on an analysis of certain facility cost breakpoints (meter, regulator, service line) that could generally be linked to annual volumes. On November 26, 2002, the Commission approved the Company's experimental unbundling program (Order No. PSC-02-1655-TRF-GU) which eliminated the distinction between sales and transportation service classes.

The Company's present tariff includes the following volumetric service classifications (Original Sheet Nos. 13-17):

- Service Classification No. 1: 0 - 1,000 Annual Therms

- Service Classification No. 2: > 1,000 - 25,000 Annual Therms
- Service Classification No. 3: > 25,000 - 100,000 Annual Therms
- Service Classification No. 4: > 100,000 - 3,000,000 Annual Therms
- Service Classification No. 5: > 3,000,000 Annual Therms

Each of the above classes has a corresponding rate schedule. In addition to the rate schedules for each volumetric service classes, the Company's current tariff also includes a Contract Transportation Service Rider (Rider CTS) applicable to customers in Service Classes that exceed 25,000 therms in annual consumption (Original Sheet No. 29).

Q. IS THE COMPANY PROPOSING CHANGES TO ITS EXISTING SERVICE CLASSIFICATIONS?

A. Yes. The Company is proposing to retain most of its existing service classes. However, IGC proposes to eliminate one service classification (No. 5, rate schedule TS-5), add one new service classification (Third Party Supplier) and modify the applicability of two classes: No. 3, rate schedule TS-3 and No. 4, rate schedule TS-4.

Q. WHICH EXISTING SERVICE CLASSES IS THE COMPANY PROPOSING TO RETAIN WITHOUT SUBSTANTIVE MODIFICATION?

A. Service Classifications No. 1 (0 – 1000 annual therms) would continue under the proposed tariff with no substantive modifications. The rate schedule associated with this class (TS-1) would also be retained without revision, other than to change the rates. In addition, the Company proposes to retain the Rider CTS without modification.

Q. WHICH SERVICE CLASSIFICTION IS THE COMPANY PROPOSING TO ELIMINATE?

A. As described in detail in Mr. Powers' testimony, the reduction in annual volume by Indiantown Cogeneration eliminates the need for the existing Service Classification No.5 and the corresponding rate scheduleTS-5. The Company proposes to delete this class.

Q. PLEASE DESCRIBE THE NEW SERVICE CLASSIFICATION THE COMPANY IS PROPOSING?

A. The Company is proposing to establish a Third Party Supplier (TPS) Service classification. The TPS class recognizes that the Company provides significant services to the gas marketers delivering gas to the Indiantown distribution system. As described later in my testimony, the Company's cost study proposes the allocation of certain recurring O&M costs to this new class.

It should be noted, that, while the proposed TPS rate schedule is new, the concept of charging gas marketers is not. Indiantown's current tariff (Section XVIII, H) allows the recovery of recurring costs for a Customer Account Administration Service (CAAS) provided to the Aggregated Transportation Service Pool Manager. Additionally, the Commission has approved the recovery of recurring transportation administrative costs through similar charges for Chesapeake Utilities and TECO Peoples Gas. The Company's current authorized CAAS includes providing meter reading data, monthly customer billing, payment processing, limited collection services, account record maintenance and other administrative services. A $2.00 per bill charge was approved by the Commission (Order No. PSC-02-1655-TRF-GU) as part of the Company's unbundling proceeding in 2002.

Q. **PLEASE DESCRIBE THE COMPANY'S PROPOSED REVISION TO SERVICE CLASSIFICATION NO. 2.**

A. Under IGC's present tariff the applicability of Service Classification No. 2 includes customers whose metered consumption is greater than 1,000 therms up to 25,000 therms per year. The Company proposes to reduce the upper annual therm threshold to 15,000 therms.

Q. **PLEASE DESCRIBE THE COMPANY'S PROPOSED REVISION TO SERVICE CLASSIFICATION NO. 3.**

A. Under IGC's present tariff the applicability of Service Classification No. 3 includes customers whose metered consumption is greater than 25,000 therms up to 100,000 therms per year. The Company proposes to reduce the lower therm threshold; the proposed level would begin at an annual consumption level of greater than 15,000 therms.

Q. **PLEASE DESCRIBE THE COMPANY'S PROPOSED REVISION TO SERVICE CLASSIFICATION NO. 4.**

A. Service Classification No. 4 (TS-4) was originally established to accommodate the Louis Dreyfus Citrus facility. At present, any customer with an annual volume greater than 100,000 therms but less than 3,000,000 therms would be assigned to this class. In October 2003, Indiantown Cogeneration was reassigned to the TS-4 class since the cogeneration plant's annual therm consumption had dropped well below the 3,000,000 therm threshold. As indicated above, the current TS-5 class is proposed for elimination. The Company is proposing to modify the existing Service Classification No.4 (TS-4) to remove the upper therm consumption limit. The proposed class would include all customers whose annual therm usage exceeds 100,000 therms.

Q. PLEASE PROVIDE A SUMMARY LIST OF THE VOLUMETRIC AND OTHER SERVICE CLASSES THE COMPANY IS PROPOSING FOR ITS NEW TARIFF.

A. The following chart displays the proposed customer classes.

Customer Classes	Annual Therm Usage
TS-1	0 up to 1000
TS-2	>1000 up to 15,000
TS-3	>15000 up to 100,000
TS-4	>100,000
CTS	>25,000
TPS	N/A

Q. DOES THE COMPANY'S CUSTOMER, SALES AND REVENUE FORECAST ACCOUNT FOR THE PROPOSED REVISIONS TO ITS EXISTING CUSTOMER CLASSIFICATIONS?

A. Yes. The forecasts of customers, sales and revenues presented in the MFRs filed in this rate proceeding are consistent with the Company's proposed customer classifications and their respective rate schedules.

Q. HAS THE COMPANY PROVIDED BILLING DETERMINANT INFORMATION THAT WILL ALLOW THE COMMISSION TO

COMPARE THE EXISTING CLASSIFICATIONS TO THE PROPOSED CLASSIFICATIONS?

A. Yes. MFR Schedules E-1 and E-5 have been prepared to enable the Commission to compare bills, therms and revenues under the existing classes to the proposed classes.

Q. DOES THE COMPANY INTEND TO MAINTAIN CUSTOMER INFORMATION THAT WILL ENABLE IT TO CONTINUE TO PROVIDE DATA TO THE COMMISSION BY TRADITIONAL CUSTOMER TYPE?

A. Yes. The Company's current and proposed Customer Information System is capable of maintaining account records by customer type. In addition, such information is necessary for the Company to apply the appropriate tax factors and certain billing adjustments that currently are based on the existing customer classes.

Q. PLEASE DESCRIBE HOW YOU ALLOCATED CAPACITY COSTS IN THE COST OF SERVICE STUDY.

A. Capacity costs were allocated on the basis of peak and average monthly sales volume for all customer classes. The principle underlying the peak and average allocator is that fixed demand costs should be apportioned to rate classes in a manner that reflects both the basis for which the costs are incurred, as well as the actual utilization of the system by customers entitled to receive service once the system has been installed.

Q. HOW WERE COMMODITY COSTS ALLOCATED?

A. Commodity related costs were allocated on the basis of annual sales volumes.

Q. PLEASE DESCRIBE HOW YOU ALLOCATED CUSTOMER COSTS.

A. Customer costs were allocated based on the relative number of customers served in each customer class. The "weighted number of customers" allocator was used to distribute costs based on the recognition that larger customers exhibit higher customer costs. Meters, regulators and service lines are generally more expensive for larger customers. The weightings used were derived from the relative investment in meters, regulators and service lines required to serve representative customers in each class. The weightings can be found on MFR Schedule E-7.

Q. HOW WERE REVENUE COSTS ALLOCATED?

A. Revenue costs were allocated on the basis of gross revenues by customer class.

Q. IT WOULD APPEAR THAT A COST OF SERVICE STUDY IS PRIMARILY A MECHANICAL ACCOUNTING OF COSTS. ARE THERE OPPORTUNITIES TO APPLY JUDGMENT, CONSIDER MARKET CONDITIONS OR OTHER MITIGATING FACTORS IN THE STUDY?

A. Yes. Cost studies, at the outset, are not simply formula based accountings of costs by rate classification. They require judgment by an experienced analyst to appropriately allocate and assign costs. An understanding of the utility's business strategy, market area and competitive position is necessary to complete an appropriate rate design. Within the cost of service study, the selection and application of allocation factors requires not only a mechanical understanding of the Company's costs, but also a common sense understanding of a variety of economic, social, regulatory and competitive considerations.

Q. SHOULD A COST OF SERVICE STUDY BE EXCLUSIVELY RELIED UPON TO ESTABLISH UTILITY RATES?

A. No. As noted above, there are a number of factors that must be considered when designing rates. One of the most critical is the competitive position of the Company in the marketplace. Customers in all rate categories have fuel alternatives. Increasingly, customers are demonstrating greater sophistication in their consideration of energy options. The relative competitive position of the Company to several fuel alternatives by customer class was discussed earlier, and is displayed in Exhibit No. ___ (JMH-3). As described in Mr. Powers' testimony, the Company's system is vulnerable to price in every rate class. On a small system, such as Indiantown Gas, the large customers appropriately contribute a substantial portion of the revenue requirement since they cause a substantial portion of the costs. However, care must be taken that the rates established for large customers are reasonable, or they will seek alternatives to the ultimate detriment of other ratepayers.

Price elasticity, proximity to the interstate pipeline and specific fuel alternatives vary greatly among customer classes. Price is only one factor considered when evaluating fuel types. There are numerous non-price issues in all customer classes that affect fuel selections. For example, maintenance concerns, fuel storage, emissions levels, appliance efficiency, comfort and aesthetics all play a part in a customer's fuel decisions. The bottom line is that customers have choices. The Company's proposed rate design utilizes a cost of service study as a starting point, but the final rate recommendations consider the above issues and make appropriate adjustments.

Q. EARLIER YOU DISCUSSED THE RESULTS OF A COMPETITIVE COST ANALYSIS PREPARED FOR EACH PROPOSED CUSTOMER CLASS. WHAT DOES THE ANALYSIS SHOW WITH REGARD TO CUSTOMERS IN THE TS-1 CLASS?

A. The Company's present and proposed rates applicable to customers in the TS-1 class (primarily residential customers) were compared to propane and electric costs for comparable usage levels on an annual basis. Exhibit No. ___ (JMH-3) displays price comparisons for customers with annual volumes less than 1000 therms. All costs are expressed in equivalent therms and reflect the different Btu value of the energy form in relation to natural gas. The Company's proposed rates, including the Pool Manger's current cost of gas for ATS customers, are competitive with propane and electricity at all usage levels. Price competition with both fuels is marginal at very low annual consumption levels. The Company does not anticipate any loss of business in the residential and small volume commercial class as a result of implementing the proposed rates.

Q. WHAT DOES THE ANALYSIS SHOW WITH REGARD TO TS-2 CUSTOMERS?

A. Exhibit No. ___ (JMH-3) also presents a cost comparison for usage levels typically associated with commercial customers in the Company's TS-2 class. The unprecedented high gas commodity costs experienced over the past three years have resulted in greater price competition for commercial accounts. Competition with propane and electricity is more of a concern for the Company at the 1000 to 15,000 annual therm level. The customers served in this volume range are predominately represented by food service and hospitality accounts. At the proposed rate levels the Company maintains a good competitive price advantage over electricity, and is generally competitive with propane.

Q. WHAT DOES THE ANALYSIS SHOW WITH REGARD TO THE TS-3 CUSTOMERS?

A. Exhibit No. ___ (JMH-3) presents a cost comparison of the proposed TS-3 gas rates with current alternate fuel prices. The Company currently serves only one account in this class, Entegra Tile. The only realistic fuel competitor in this class is propane. The proposed gas rates for this class provide a small (10%) but significant savings compared to propane.

Q. DID YOU COMPLETE A FUEL COST COMPARISON FOR THE TS-4 CUSTOMER CLASS?

A. Yes. I completed a cost comparison analysis for both of the Company's large volume industrial accounts. I did not prepare an exhibit for either analysis. Both customers consume well over two million therms per year. The cogeneration plant uses natural gas for a specialized application (flame stabilization). There is no rational fuel alternative for the cogeneration plant known to the Company other than propane. The plant is capable of using propane and, for a variety of operational reasons, has done so on several occasions. The cost study converted the total revenue from the Company's proposed rates to a $ per therm equivalent. At the forecast 2,600,000 annual therm level the cost per therm equivalent from proposed rates would be approximately $0.142. The cogeneration plant purchases gas from a marketer, so its fuel costs are not known to the Company. However, we assumed an interstate pipeline annual delivered capacity cost of approximately $0.06 per therm and commodity costs at the current NYMEX future price for 2004 of $0.53 per therm. Total per therm costs for the plant would be approximately $0.73 per therm. It is unlikely that the plant could purchase propane at a significantly lower price on an annual basis.

The citrus plant has used natural gas as its sole fuel source since commencing operations in 1972. The plant could theoretically convert to fuel oil or propane. However, at the Company's proposed rates it makes little economic sense to entertain an expensive fuel conversion. My analysis of the Company's proposed rates plus a reasonable cost of natural gas compared to the alternatives of oil or propane indicate significant savings with natural gas. The citrus plant is forecast to use approximately 2,200,000 therms in the projected test year. I converted the total revenue from the Company's proposed rates to a $ per therm equivalent. At the forecast annual therm level the cost per therm equivalent from proposed rates would be approximately $0.06 (the citrus plant has a significantly lower demand requirement than the cogeneration plant). The citrus plant also buys gas from a marketer so its fuel rates are unknown. Applying the same commodity and capacity cost as used in the cogeneration analysis, results in a total estimated natural gas cost of $0.65, well below any likely propane or oil delivered cost.

Q. DOES THE COMPANY'S PROPOSED RATE DESIGN REFLECT ADJUSTMENTS BASED ON ALTERNATE FUEL PRICING OR OTHER MARKET FACTORS.

A. Yes. The Company considered alternate fuel prices, customer rate impact and other market factors in designing rates. The proposed classes of service and their respective rates were selected based on the Company's primary need to retain customers. In setting rates for the low usage class (TS-1), the Company was particularly sensitive to the Company's competitive concerns with electricity and propane. The Company's rate design for non-residential customers in the TS-2 class also proposes rates that reflect competition with electricity and propane gas. Proposed rates for the large industrial classes are designed to provide the Company its best opportunity to compete with the other alternatives available to large volume customers, yet recover an appropriate cost of service.

Q. PLEASE BRIEFLY SUMMARIZE THE PROCESS EMPLOYED TO IMPLEMENT MARKET BASED ADJUSTMENTS TO THE COST ALLOCATIONS IN STAFF'S MODEL.

A. An initial cost allocation was prepared using the Staff's cost of service model without modification. A second cost study was prepared that re-allocated certain costs among classes to reflect price competition, and other market concerns. As described above, this second cost allocation was accomplished through the direct and special assignment of costs in Staff's model. All of the cost re-allocations occurred in the O&M expense classification "All Other". The specific adjustments included reducing the TS-1 costs by $25,098 and $77,000. The $25,098 amount was allocated to the new TPS customer class and forms the cost basis for the new TPS rates. I also increased the cost allocations to the TS-2 class by $1,950, to the TS-3 class by $50, and the TS-4 class by $75,000. The final proposed allocation of cost of service by customer class, as filed, is presented on MFR Schedule H-2 pages 3 and 4. The allocation of rate base to each customer class is included in MFR Schedule H-2, page 2.

Q. IS THE COMPANY PROPOSING CHANGES TO ITS CURRENT RATE STRUCTURE FOR VOLUMETRIC CUSTOMER CLASSES?

A. Yes. The rate structure proposed for all volumetric rate classes includes the continuation of a traditional fixed monthly Customer Charge and a variable Transportation Charge based on the quantity of gas consumed during a billing period. However, the TS-3 and TS-4 classes include a proposed fixed Demand Charge component. In addition, the overall proposed rate structure is intended to begin a shift toward a Straight Fixed Variable (SFV) or Modified Fixed Variable (MFV) rate design.

Q. TO WHAT EXTENT IS THE COMPANY PROPOSING TO MOVE TOWARD A SFV OR MFV RATE STRUCTURE?

A. The Company is proposing a rate design for all customers that incorporates the primary elements of SFV of MFV rates. That is, a significant portion of the Company's proposed revenue requirement would be collected through an increase in the existing fixed monthly customer charges, or for larger volume accounts, through a new fixed monthly demand charge. The variable rate component would collect a smaller percentage of the overall revenue requirement. The revenue recovered through the Company's fixed customer and demand charges represents approximately 79% of the total proposed target revenues in the Projected Test Year compared to less than 33% in the Historic Base Year.

Q. WHY IS SFV OR MFV APPROPRIATE?

A. As the interstate pipelines unbundled FERC recognized that, in the absence of commodity sales by the pipelines, few variable cost components remained. The pipelines continued to have compressor and odorization costs that were dependent on gas throughput. However the revenue requirement was largely defined by fixed costs unaffected by the volume of gas transported on the pipeline. The pipeline made an investment in its facilities and incurred operating costs that did not vary with usage. The SFV rate design used by virtually all FERC regulated pipelines collects the vast majority of revenues through fixed demand or capacity reservation charges. For example, FGT's rates for reserving capacity represent approximately 95% of their total charges. These reservation or demand rates are applied on a take or pay basis, further evidence of FERC's acknowledgement that fixed costs are more appropriately recovered through fixed charges. At the outset of open access several pipelines, including FGT, adopted a modified version of SFV rate design. The MFV design spilt the fixed rate components into two separate fixed charge elements, similar to the Customer Charge and Demand Charge the Company is proposing for larger customers.

The Company has fewer variable cost elements than the interstate pipelines. Apart from a minimal annual cost for odorant, there are few expenses that can be directly linked to throughput. The Company understands that a complete shift to fixed rates for all classes is not practical at this time. Nonetheless, the Company is proposing to initiate moving toward a rate design that may ultimately recover a majority of the Company's revenue requirement from fixed charges.

Q. PLEASE DISCUSS THE COMPANY'S DEMAND CHARGE PROPOSAL IN GREATER DETAIL.

A. The Company's proposed rate design begins to differentiate rates on the basis of load factor rather than simply using annual consumption to classify customers. The proposed rates for the TS-3 and TS-4 classes recover 100% of fixed capacity related costs through a fixed monthly demand charge. As noted above, the Company assigned capacity costs based on the peak and average usage characteristics of each of its customer classes. Capacity costs for any gas system represent fixed investments in facilities, primarily mains and services.

The Company believes that it is appropriate and consistent with its objective to move toward a SFV rate design to establish a fixed charge that recovers, at least a portion of its fixed capacity costs. Although an excellent case could be presented to apply a demand charge component to all rate classes, the Company proposes that, in this proceeding, the charge be established only for the TS-3 and TS-4 large volume classes.

The proposed Demand Charge was established using the following methodology. Staff's cost of service model produces a traditional classification of functionalized costs. A system annual capacity cost was determined from the cost of service study. The peak month consumption for the system was determined by reviewing historical consumption data from the past five years, including historic base year. The contribution to the system peak month by rate class was also ascertained from the same data-base. A peak and average month consumption for each class was derived. The results of this computation are used in MFR Schedule H-2 to allocate capacity costs to the respective rate classes. No adjustments were made to the classification or allocation of capacity cost methods used in staff's model.

Q. HOW DOES THE COMPANY PLAN TO BILL THE RATE CLASS CAPACITY COST ALLOCATIONS TO INDIVIDUAL CUSTOMERS?

A. Once capacity costs were determined for each class, it was necessary to devise a new billing determinant to appropriately recover such costs from the TS-3 and TS-4 customers. Capacity costs are, by definition, costs incurred by a utility to meet the on-demand service requirements of customers. The Company proposes to utilize a demand related measurement widely recognized in the gas industry and already in use on the IGC distribution system. Customers in the TS-3 and TS-4 classes would utilize a Maximum Daily Transportation Quantity (MDTQ) expressed in Dekatherms (Dt) as the Demand Charge billing determinant quantity. The MDTQ represents an assessment of the peak demand requirements placed on the utility by a respective customer. The customer's individual MDTQ would be multiplied by the Demand Charge rate to determine a monthly billing amount.

Q. HOW WILL THE MDTQ FOR INDIVIDUAL CUSTOMERS BE DETERMINED?

A. Any customer whose annual therm consumption exceeds 100,000 or any customer electing to transport under the provisions of Section XVIII, General Terms and Conditions, Individual Transportation Service, in the approved IGC tariff will have an MDTQ established by contract. Indiantown Cogeneration has an existing Transportation Services Contract that stipulates a MDTQ (approved by the Commission as a special contract, Order No. PSC-03-1156-PAA-GU). Louis Dreyfus Citrus has a tariff authorized existing Transportation Services Agreement with an MDTQ. For those customers that do not have an MDTQ established by contract or agreement (Entegra Tile) the MDTQ would be based on the peak consumption month occurring during the past twenty-four months divided by the days in the respective peak month. The MDTQ for any new customers with no consumption history would be based on estimated usage.

Q. IS THE COMPANY PROPOSING TO REVIEW AND ADJUST MDTQ'S ON AN ANNUAL BASIS.

A. Yes. Each year, in January, the Company would reassess each TS-4 customer's MDTQ based on the highest recorded daily usage established by the Company's electronic metering equipment at the customer site during the previous twenty-four months. The MDTQ in any subsequent annual period would be the higher of the customer's contractual MDTQ with the Company or the highest recorded quantity during the previous twenty-four month period. The MDTQ for customers with no AMR device would also be assessed in January of each year. The revised MDTQ would be based on the peak consumption month over a rolling twenty-four month period divided by the days in the respective peak month.

Q. PLEASE DESCRIBE HOW THE PROPOSED DEMAND RATE WAS DERIVED?

A. The annual capacity cost allocation produced by staff's model for the TS-3 and TS-4 classes was divided by the by the cumulative MDTQ's for all three customers. This computation resulted in a Demand Charge of $2.51 per Dt.

Q. HOW DOES THE CREATION OF A DEMAND CHARGE HELP THE COMPANY ESTABLISH FAIR AND EQUITABLE RATES?

A. In addition to meeting the objective of increasing fixed cost recovery through fixed charges, the Demand Charge proposal also addresses a major concern specific to the Indiantown system. The Company currently has two large industrial customers in the same rate class with virtually the same annual consumption, but dramatically different demand requirements. Historically, these customers (Indiantown Cogeneration and Louis Dreyfus Citrus) were served in separate rate classes. Until 2002, there was a substantial difference in their respective end-use quantities.

At the time the cogeneration plant requested service, IGC had been serving the citrus facility for over twenty years (formerly Caulkins Citrus). As described in Brian Powers' testimony, the Company received Commission approval (Authority No, G-96-03) for the cogeneration special contract in December 1996. Later that year the Company filed a petition to establish a new rate for the citrus plant. A cost of service study was produced to guide rate setting. The Commission on December 2, 1996 (Order No. PSC-96-1452-FOF-GU) established a new lower rate for the citrus plant. In 1999, the approved rates for the cogeneration plant produced a margin contribution equal to approximately 79% of the Company's total revenue requirement from sales. The citrus plant produced approximately 14% of total margins.

In the Company's 2002 rate restructuring (Order No. PSC-02-1666-PAA-GU) the Company proposed rate reductions for both the cogeneration and citrus plants. Costs were specifically reassigned to the smaller volume classes in an effort to move the Company's overall rates closer to parity between classes, and reduce IGC's dependence on one large customer for the bulk of its margin revenue. The Company produced a new cost study that established a TS-5 rate class specifically for the cogeneration plant and a TS-4 class specifically for the citrus plant. (For a variety of internal contract procedural reasons the cogeneration plant elected to retain its existing, and higher, special contract rates, and was never billed under the TS-5 rate schedule.) The

2002 cost study produced cost allocations and a rate design that resulted in the cogeneration plant contributing approximately 51% of the Company's revenue requirement from sales, and the citrus plant approximately 24%. The Company's rates recovered the majority of these costs through a variable rate tied to consumption.

Dramatic reductions in consumption at the cogeneration plant have substantially affected the Company's ability to recover its costs. As described in Mr. Powers' testimony, the cogeneration plant's gas consumption has declined from 9,100,000 therms in 1999 to less than 2,500,000 therms in 2002, with a similar volume of 2,600,000 therms projected for 2003. As noted above, the cogeneration plant's volumes decreased to the point where they qualified for the existing TS-4 service class, and were reassigned in November 2003. This re-assignment resulted in a $3000 per month Customer Charge reduction and a $0.00766 reduction in the Transportation Charge.

The cogeneration plant's consumption has declined by 70% since 1999; however, their demand requirements for transportation access to the IGC distribution system have not. During 2003 the cogeneration plant's contract with IGC was renegotiated. The contract was updated to reflect the migration of the cogeneration facility to transportation service. The revised agreement was approved by the Commission as a special contract on October 20, 2003 (Order No. PSC-03-1156-PAA-GU). Although the plant had significantly reduced consumption, the new agreement established an MDTQ of 9,500 Dt per day over the thirty-year term of the contract. The plant's actual historic peak day reached 11,803 MCF (12,240 Dt equivalent) on September 27, 1999. More recently, and subsequent to the significant annual volume reductions, the plant achieved a peak day of 8,497 MCF (8,904 Dt equivalent) on April 14, 2003. In contrast to the cogeneration plant, the Louis Dreyfus tariff Transportation Service Agreement, executed on October 30, 2001 includes a MDTQ of 800 Dt/day. The actual peak day requirements for the citrus plant over the past twenty-four months were 1,550 MCF (1,612 Dt equivalent) as recorded by the Company's AMR device on May 22, 2002.

Instituting a Demand Charge allows the Company to continue to differentiate the Cogeneration and citrus plants based on their cost to serve, while at the same time include them in the same volumetric rate category. In addition, it achieves a revenue requirement contribution from both customers that is consistent with both the cost allocation from the study and each customer's historic contribution levels. Both customers are forecast to use a similar quantity of therms in the projected test year. However, the cogeneration plant's 9,500 Dt/day MDTQ represents approximately 75% of the total IGC distribution system capacity, while the citrus plant's 1,550 MCF/day (1612 Dt equivalent) MDTQ represents less than 15% of system capacity. The proposed Demand Charge will apportion the Company's fixed capacity costs allocated to the TS-4 class to the customer responsible for those costs based on the distribution system transportation capacity required by the respective customers. Instituting a demand charge enables the Company to retain the volumetric service classes customers understand, and at the same time, appropriately recover capacity costs from the customers causing such costs. The proposed rate design will produce revenues from the cogeneration plant equal to approximately 57% of the total revenue requirement. The citrus plant will contribute almost 19% under the new rates. In addition, the application of the Demand Charge to the TS-3 customer, Entegra Tile, extends the recovery of a greater portion of the Company's fixed capacity costs to all of the larger volume non-residential accounts.

Q. ARE YOU PROPOSING ANY CHANGE TO THE COMPANY'S CUSTOMER CHARGES?

A. Yes. I am proposing changes to all of the monthly Customer Charges in the Company's current rate design. Exhibit No. ___(JMH-4) displays the difference between the existing and proposed monthly Customer Charges. Modifications to the Company's existing Customer Charges are designed to provide additional revenue stability for the Company by allowing it to recover a greater portion of fixed customer costs to serve through a fixed charge. The Company's intent is to move individual rate elements closer to cost based levels. The unit cost data from the cost study was used to guide the Company's determination of appropriate Customer Charge rates.

Q. PLEASE DESCRIBE THE PROPOSED RATE DESIGN TO RECOVER CERTAIN RECURRING COSTS OF PROVIDING SERVICES TO THE COMPANY'S APPROVED POOL MANAGER AND OTHER GAS MARKETERS; THE THIRD PARTY SUPPLIER (TPS) CLASS.

A. As previously stated, the Company provides certain administrative and billing services to the Pool Manager as part of its Aggregated Transportation Service (ATS) program. In addition, the Company offers Individual Transportation Service to customers over 25,000 annual therms. To date, two customers are individually transporting. The Company is proposing to recover the recurring costs to provide service to the Pool Manager and other gas marketers through charges to the entities causing the cost; that is the Pool Manager and marketers.

There are three cost elements I am proposing to allocate to this new service class. The cost of service study identifies operation and maintenance expenses related to Customer Accounts on MFR Schedule H-1, page 3. I allocated 25% of the costs classified in account 902 Meter-Reading Expense and 25% of the costs classified in account 903 Records and Collection Expense to the TPS class. The allocation from account 902 totaled $1,597; the allocation from account 903 totaled $9,501. I also assigned 100% of the incremental increase in salary expense ($14,000) related to increasing Melissa Powers' work schedule from one-half to three-quarter time. As described in Brian Powers' testimony, this work schedule increase is directly related to the administration of the Company's unbundled transportation programs. The total cost allocated to the proposed TPS class is $25,098.

The Company is proposing to increase its existing $2.00 fixed charge per transportation bill per month to $3.11. The Company is forecasting that it will provide 8,061 transportation service bills in the Projected Test Year. The proposed $3.11 rate would generate annual revenue equal to the $25,098 allocated cost. This revenue has been reflected in a separate rate class in the Company's cost of service study and appropriately adjusted out of the target revenues used to establish rates by volumetric class.

Q. IS THE COMPANY SEEKING RECOVERY OF ANY NON-RECURRING TRANSPORTATION COSTS IN THIS PROCEEDING?

A. No. The Company has an existing Transportation Cost Recovery (TCR) mechanism in place to recover the non-recurring costs of its authorized unbundling program (Order No, PSC-03-1109-PAA-GU). Should such expenses occur in the future the company would request that the Commission authorize a new TCR process.

Q. DID YOU CONSIDER THE COMPANY'S RATE OF RETURN FOR YOUR PROPOSED CUSTOMER CLASSES AT PRESENT RATES IN YOUR ANALYSIS?

A. Yes. Prior to designing the Company's final proposed rates I reviewed the rate of return results for each of the new customer classes. The returns for each proposed customer class at present rates is displayed on MFR schedule H-3, page 2. At present rates, it is clear that substantial rate of return disparities exist within and between classes.

Q. HOW DID YOU DEVELOP THE PROPOSED RATES?

A. The Company's proposed rate design results in each customer moving toward a more uniform contribution to costs compared to present rates. The final rates were designed on the basis of cost of service by class, the competitive considerations discussed above and a review of the current structure of rates and classes. The rate design I am proposing on the Company's behalf establishes rates of return for each customer class that continue to improve the historical inequity within and between classes. The final rate design ensures that each proposed volumetric class generates a return as close to the Company's projected cost of capital of 10.09% as could be achieved without producing excess competitive risk of fuel switching. Rates of return for each proposed class under projected rates are included in MFR Schedule H-3, page 3.

Q. IS THE COMPANY PROPOSING CHANGES TO ITS OTHER OPERATING REVENUE CHARGES?

A. No adjustments to other operating revenue charges are proposed. The forecast of revenue in the Projected Test Year includes ten new residential connection charges, consistent with the customer forecast.

The proposed other revenue charges are projected to generate $4,120 in the Proposed Test Year. The current other revenue charges are displayed on MFR Schedule E-1, page 3.

Q. PLEASE COMPARE THE PROPOSED RATES TO THE PRESENT RATES.

A. A comparison of present and proposed base rates and customer charges by customer class is presented in MFR Schedule H-3, page 5, and is summarized on Exhibit No. ___ (JMH-4).

Q. HOW MUCH REVENUE WILL THE PROPOSED RATES PRODUCE?

A. The rates and charges are designed to produce additional revenues of $306,757, as indicated on MFR Schedule H-3, page 4. Total target revenues under the proposed rates are $649,675.

Q. PLEASE SUMMARIZE THE CONCLUSIONS YOU HAVE REACHED BASED ON YOUR COST ANALYSIS AND RATE DESIGN.

A. The cost of service analysis provided a reasonable basis upon which to begin the design of rates by customer class. I compared the initial results of the cost study to the Company's historic rates, the competitive cost analysis and the Company's objective to reduce rate subsidizations among and within classes. I specifically worked to address potential inequities created by establishing rates based solely on annual consumption, without accounting for demand requirements. My final rate design brought the rate of return for all customer classes close to the Company's cost of capital. The proposed rates substantially reduce the subsidization the large volume customers have been required to contribute to the overall rate of return. The rate design begins to shift toward a SFV or MFV structure for all accounts. In the Company's view, the SFV or MPV structure represents the future for LDC rate design. The proposed rate design produces rates which are in line with customer alternatives and positions the Company to achieve its business objectives. I believe the proposed rate design is just and reasonable, producing fair and equitable rates for each customer class.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

LIST OF MFR SCHEDULES SPONSORED BY JEFF HOUSEHOLDER

Schedule		Title
E-1	Pp. 1-3	Cost Of Service - Therm Sales and Revenues
E-2	Pp. 1	Cost Of Service - Revenues at Present and Proposed Rates
E-3	Pp. 1-4	Cost Of Service - Miscellaneous Revenue
E-4	Pp. 1-2	Cost Of Service - Peak Monthly Sales Volumes
E-5	Pp. 1-4	Cost Of Service - Monthly Bill Comparisons
E-6	Pp. 1-5	Cost Of Service - Derivation of Overall Cost of Service
E-7	Pp. 1	Cost Of Service - Meter Set and Service
E-8	P. 1	Cost Of Service - Dedicated Facilities
E-9	P. 1	Cost Of Service - Tariff
F-10	P.1	Calculation Of Interim Rate Relief - Deficiency Allocation
H-1	P. 1	Cost Of Service - Classification of Rate Base - Plant
H-1	P. 2	Cost Of Service - Classification of Rate Base – Accum. Dep.
H-1	Pp. 3-4	Cost Of Service - Classification of Expense
H-1	P. 5	Cost Of Service - Summary
H-2	P. 1	Cost Of Service - Development of Allocation Factors
H-2	Pp. 2-5	Cost of Service - Allocation Of Rate Base To Customer Classes
H-2	P. 6	Cost Of Service - Summary
H-3	P. 1	Cost Of Service - Derivation of Revenue Deficiency

SCHEDULE F-10

CALCULATION OF INTERIM RATE RELIEF - DEFICIENCY ALLOCATION

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE THE ALLOCATION OF INTERIM RATE RELIEF.

TYPE OF DATA SHOWN:
HISTORIC BASE YEAR DATA: 12/31/02
WITNESS: HOUSEHOLDER

COMPANY: INDIANTOWN GAS COMPANY

DOCKET NO: 030954-GU

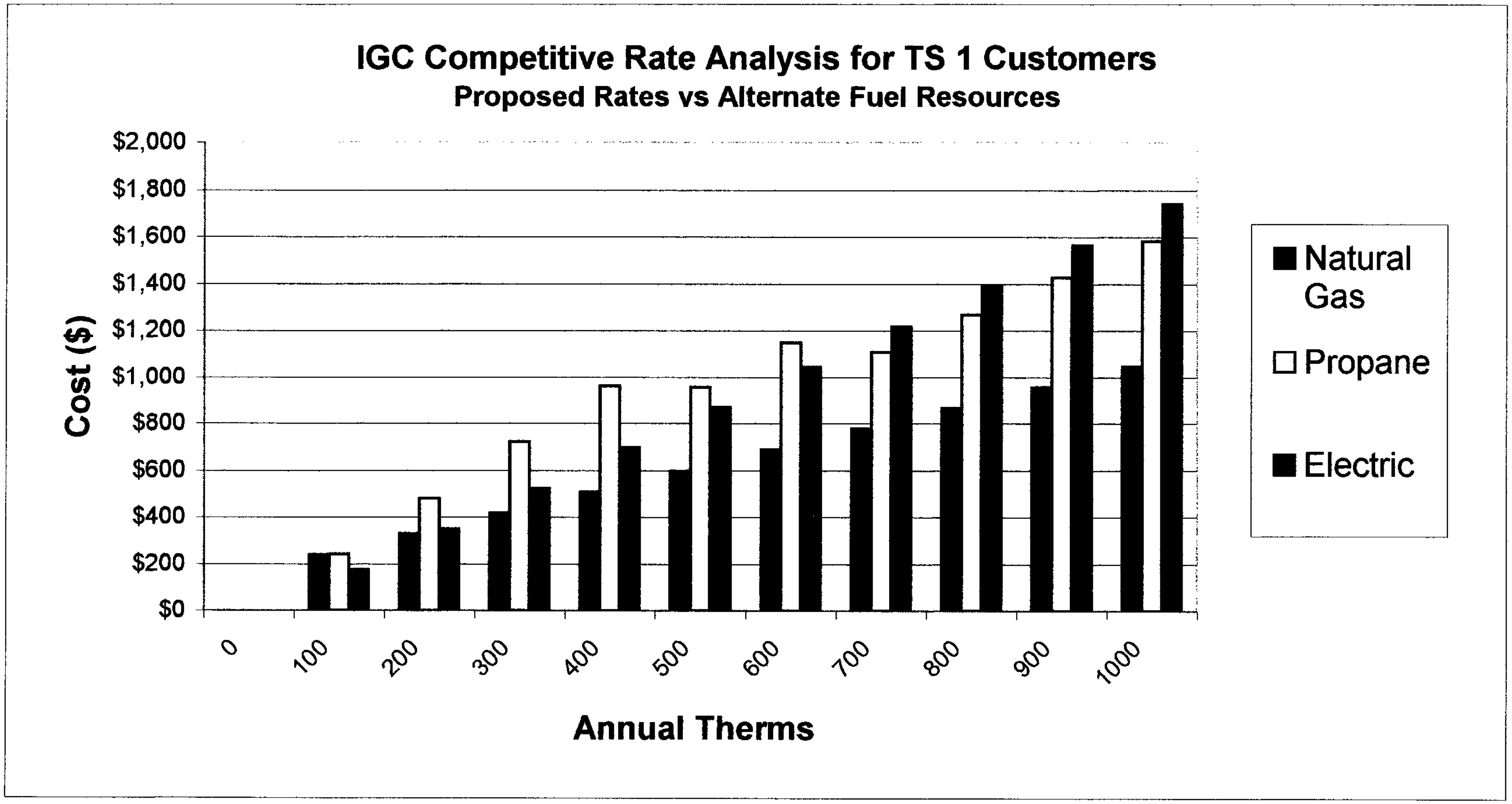
YEAR ENDED 12/31/02

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
LINE NO.	RATE SCHEDULE	BILLS	THERM SALES	CUSTOMER CHARGE	ENERGY CHARGE	TOTAL (4+5)	DOLLAR INCREASE	% INCREASE	INCREASE CENTS PER THERM
1	TS - 1	7,585	154,689	$40,457	$11,319	$51,776	$19,802	38.25%	$0.1280
2	TS - 2	293	99,294	3,205	6,126	9,331	3,569	38.25%	0.0359
3	TS - 3	24	30,427	320	1,867	2,187	836	38.25%	0.0275
4	TS - 4 **	24	4,767,009	68,700	212,851	281,551	107,687	38.25%	0.0226
5	TS - 5	0	0	0	0	0	0	38.25%	0.0000
6		0	0	0	0	0	0	0.00%	0.0000
7		0	0	0	0	0	0	0.00%	0.0000
8		0	0	0	0	0	0	0.00%	0.0000
9		0	0	0	0	0	0	0.00%	0.0000
10	TOTAL	7,926	5,051,419	$112,682	$232,163	$344,845	$131,896	38.25%	$0.0261

** Cogeneration Plant became a TS - 4 customer on November 1, 2003 (Customer was previously billed under a Special Contract rate).

SUPPORTING SCHEDULES: F-7

RECAP SCHEDULES:

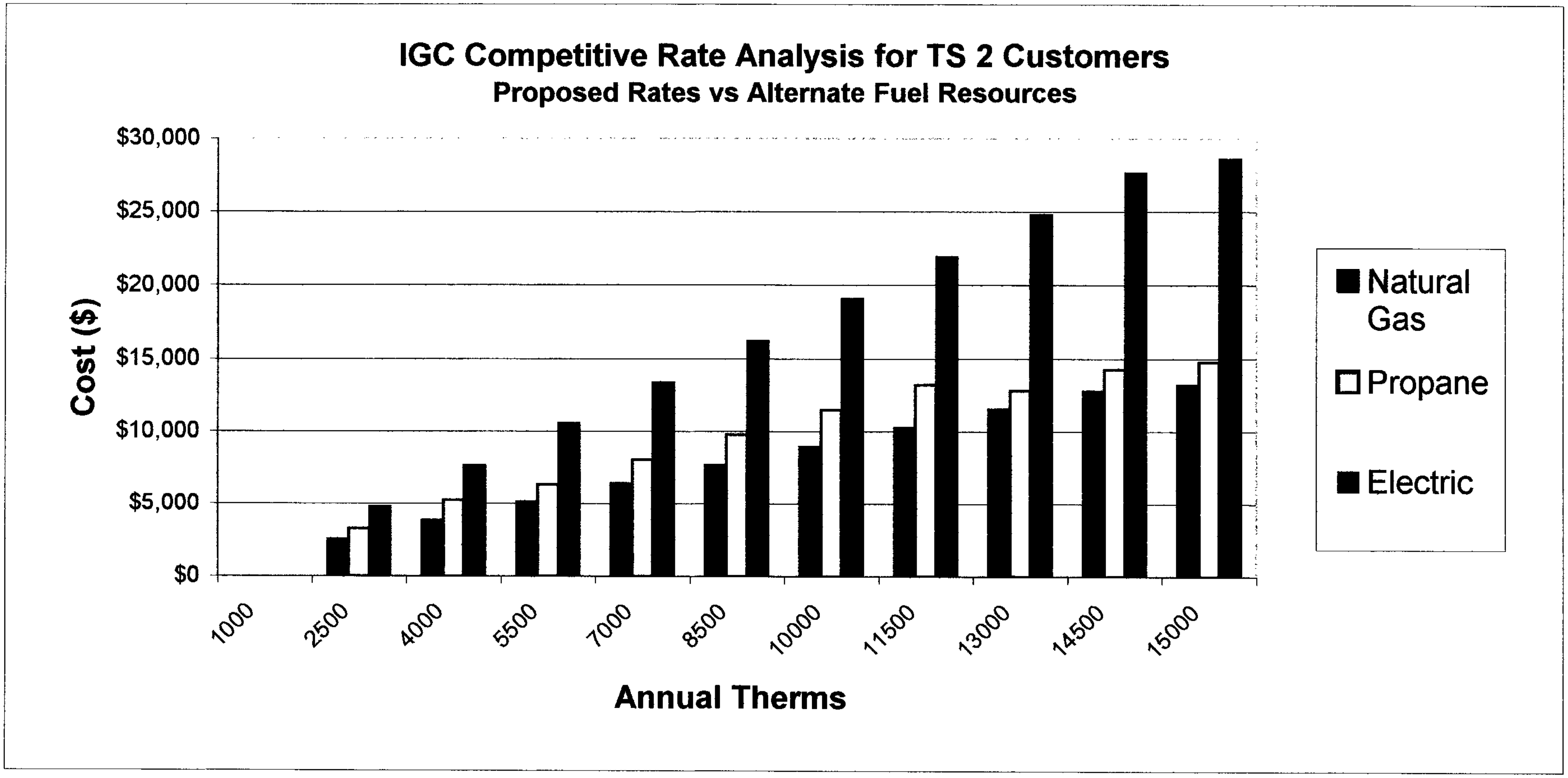


Therm Usage	0	100	200	300	400	500	600	700	800	900	1000
Natural Gas	$0.00	$239.50	$329.00	$418.50	$508.00	$597.50	$687.00	$776.50	$866.00	$955.50	$1,045.00
Propane	$0.00	$240.24	$480.48	$720.72	$960.96	$955.50	$1,146.60	$1,108.38	$1,266.72	$1,425.06	$1,583.40
Electric	$0.00	$174.04	$348.08	$522.13	$696.17	$870.21	$1,044.25	$1,218.29	$1,392.34	$1,566.38	$1,740.42

Percent difference of Indiantown TS 1 to Alternate Fuel Sources

Propane	0.0%	58.4%	58.4%	58.4%	58.4%	47.7%	47.7%	36.8%	36.8%	36.8%	36.8%
Electric	0.0%	-37.6%	5.5%	19.8%	27.0%	31.3%	34.2%	36.3%	37.8%	39.0%	40.0%

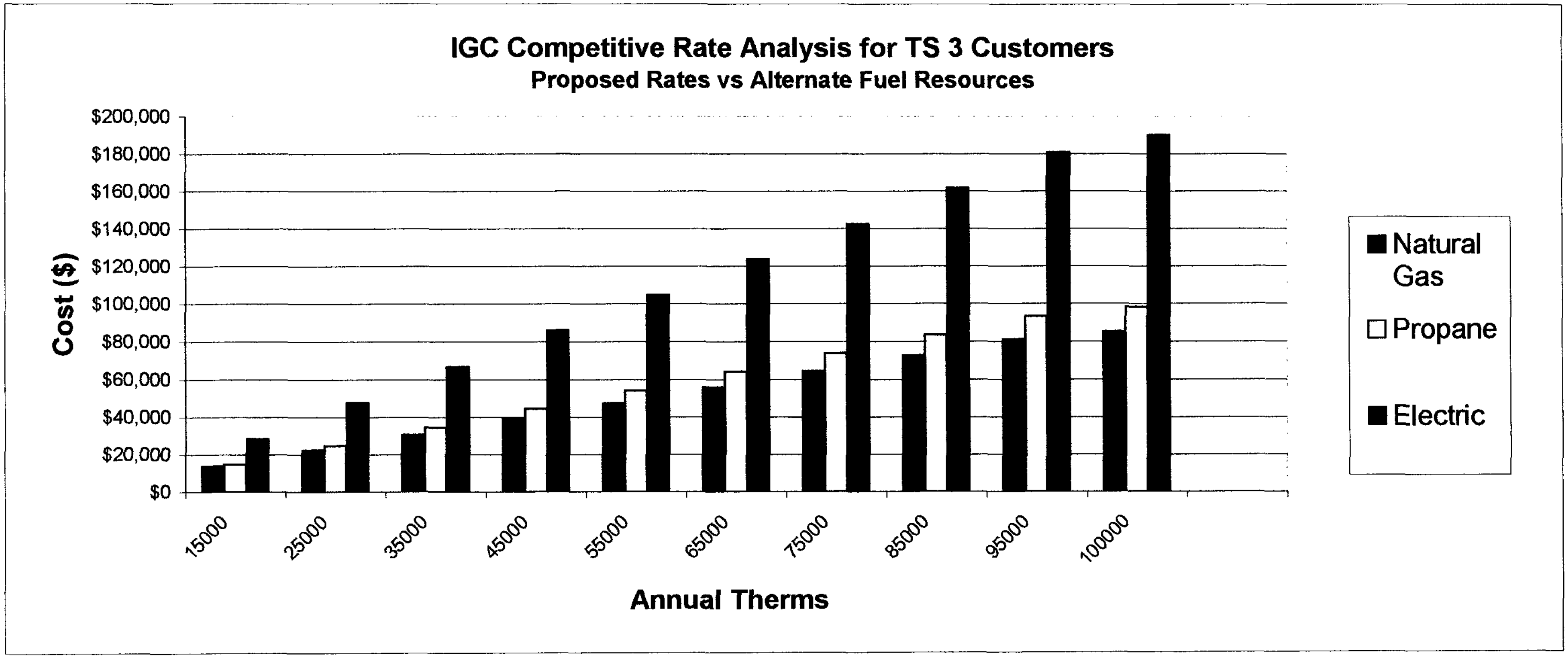
Exhibit No. ___ (JMH-3)
Docket No. 030954-GU
Indiantown Gas Company



Therm Usage	1000	2500	4000	5500	7000	8500	10000	11500	13000	14500	15000
Natural Gas	$0.00	$2,547.50	$3,824.00	$5,100.50	$6,377.00	$7,653.50	$8,930.00	$10,206.50	$11,483.00	$12,759.50	$13,185.00
Propane	$0.00	$3,276.00	$5,241.60	$6,306.30	$8,026.20	$9,746.10	$11,466.00	$13,185.90	$12,776.40	$14,250.60	$14,742.00
Electric	$0.00	$4,761.25	$7,618.00	$10,474.75	$13,331.50	$16,188.25	$19,045.00	$21,901.75	$24,758.50	$27,615.25	$28,567.50

Percent difference of Indiantown TS 2 to Alternate Fuel Sources

Propane	0.0%	22.2%	27.0%	19.1%	20.5%	21.5%	22.1%	22.6%	10.1%	10.5%	10.6%
Electric	0.0%	46.5%	49.8%	51.3%	52.2%	52.7%	53.1%	53.4%	53.6%	53.8%	53.8%



Therm Usage	15000	25000	35000	45000	55000	65000	75000	85000	95000	100000
Natural Gas	$13,822.10	$22,222.10	$30,622.10	$39,022.10	$47,422.10	$55,822.10	$64,222.10	$72,622.10	$81,022.10	$85,222.10
Propane	$14,742.00	$24,570.00	$34,398.00	$44,226.00	$54,054.00	$63,882.00	$73,710.00	$83,538.00	$93,366.00	$98,280.00
Electric	$28,567.50	$47,612.50	$66,657.50	$85,702.50	$104,747.50	$123,792.50	$142,837.50	$161,882.50	$180,927.50	$190,450.00

Percent difference of Indiantown TS 3 to Alternate Fuel Sources

Propane	0.0%	9.6%	11.0%	11.8%	12.3%	12.6%	12.9%	13.1%	13.2%	13.3%
Electric	0.0%	53.3%	54.1%	54.5%	54.7%	54.9%	55.0%	55.1%	55.2%	55.3%

INDIANTOWN GAS COMPANY
COMPARISON OF PRESENT AND PROPOSED RATES

The following table provides information to enable customers to compare rates under the existing classes to the proposed classes. The Company's existing and proposed service classes are based on annual therm transportation volume without regard to customer type. The service classes do not distinguish between residential, commercial and industrial customers. For example, the proposed rate schedule Transportation Service-1 (TS-1) is designed for any customer transporting up to 1000 annual therms. The proposed Third Party Supplier (TPS) rate schedule applies only to gas marketers delivering gas supply to the Company's distribution system. Rate classes TS-3 and TS-4 have a proposed Demand Charge rate element based on the customers Maximum Daily Transportation Quantity (MDTQ) expressed in dekatherms (Dt). The existing TS-5 class is proposed for elimination since no customer currently qualifies for the class. The Company is proposing no changes to its existing Miscellaneous Service Charges.

Proposed Rate Schedule	Current Rates	Proposed Rates
TS-1 (0 – 1000 annual therms)		
Customer Charge, per month	$9.00	$12.50
Distribution Charge, per therm	$0.1370	$0.0950
TS-2 (>1000 up to 15,000 annual therms)		
Customer Charge, per month	$21.00	$35.00
Distribution Charge, per therm	$0.06206	$0.05156
TS-3 (>15,000 up to 100,000 annual therms)		
Customer Charge, per month	$50.00	$60.00
Demand Charge, per MDTQ (Dt)	$ --	$2.51
Distribution Charge, per therm	$0.05562	$0.04007
TS-4 (>100,000 annual therms)		
Customer Charge, per month	$1500.00	$2000.00
Demand Charge, per MDTQ (Dt)	$ --	$2.51
Distribution Charge, per therm	$0.03754	$0.02317
TPS (Third Party Supplier)		
Charge per customer bill, per month	$ --	$3.11
Miscellaneous Service Charges		
Account Opening Charge (change of customer)	$15.00	$15.00
Account Turn-on or Reconnection	$35.00	$35.00
Collection at Customer Premises	$10.00	$10.00
Service Initiated by Special Appointment or After Hours	$25.00	$25.00
Late Payment Charge	1.5% per month	1.5% per month
Returned Check Charge, whichever is greater	$25.00 or 5%	$25.00 or 5%