Grand Island, Nebraska
Electric Department

Integrated Resource Plan, 2007

April 2007

Executive Summary for WAPA

Integrated Resource Plan, 2007 pertains to the Grand Island Electric Department. The City of Grand Island, Nebraska owns and operates a municipal electric system serving 23,000 customers within an 83 square mile service area surrounding Grand Island.

In this era of low load growth, utilities can not afford to install significant excess capacity, with the intent of eventual full utilization. Cost effective power supply is now maintained by some form of joint ownership. Upon commissioning, new units can be expected to operate at nearly full output. Individual utilities have resorted to small and frequent capacity additions, rather than large and infrequent expansions. Grand Island is participating in OPPD's (Omaha Public Power District) Nebraska City #2 plant, scheduled for commercial operation in 2009; this participation was investigated in **IRP, 2003**.

Since the OPPD plant commencement, an additional 220 MW coal-fired generating plant, Whelan Energy Center #2, is being constructed in Hastings, Nebraska, just 25 miles south of Grand Island. This unit is scheduled to become operational in February 2011. Grand Island is committed to a 15 MW participation level in the facility.

Although there are other significant measurable benefits to participation, such as base-load energy and additional capacity, the primary justification is to coordinate planning with other utilities. It appears that the majority of Nebraska electric utilities will need to add capacity sometime between 2017 and 2019. In the absence of Whelan Energy Center #2 participation, Grand Island would need additional base-load generation shortly before this period. By participating in Whelan Energy Center #2, Grand Island's planning horizon will advance by three years, to better coincide with the schedules of other utilities.

Introduction

<u>Integrated Resource Plans</u>: The Energy Policy Act of 1992 mandated that electric utilities periodically produce and adopt an Integrated Resource Plan. Grand Island's Integrated Resource Planning process began 1996. This consisted of initial consideration of: 58 conservation options, 3 load building options, 2 load management options, and 18 supply side options. After screening, 9 supply side options and 5 demand side programs were examined in greater detail. Ultimately, supply side expansion was the realistic option. Subsequent Integrated Resource Plans, in 2001 and 2003, examined supply side options.

The initial concern was to satisfy an impending capacity need. **IRP, 2001** resulted in the addition of two 34 MW (summer rating) combustion turbines at GI's Burdick Station. **IRP, 2001** was adopted by the Grand Island City Council on March 27, 2001, followed by a Public Hearing at the Nebraska Power Review Board on May 4, 2001.

A concluding statement of **IRP, 2001**: "Although demand requirements are satisfied through 2016, Grand Island must reconsider energy resources before that date." (i.e. 2012) The Grand Island Electric Department is reluctant to become overly dependent on generation fueled by natural gas. With capacity needs satisfied, growth in energy needs can be through incremental additions of coal generation. In the latter half of 2001, Grand Island, in response to solicitations, expressed interest in two proposed base-load power plants, which would eventually be named Whelan Energy Center #2 and Nebraska City #2.

Omaha Public Power District's (OPPD) Nebraska City #2 (NC2) progressed more rapidly than did Whelan Energy Center #2. **IRP, 2003** considered the integration of 30 MW NC2 participation with Grand Island's generation. In the decade following the planned 2009 commissioning, Grand Island anticipated saving a total of $37 million, by not operating Burdick Station steam units on natural gas. In addition to the savings, Grand Island gained additional generating capacity. NC2 remains on schedule for 2009 operation; after construction contracts were negotiated by OPPD, Grand Island's participation share increased to 33 MW.

Certainty of Whelan Energy Center #2 (WEC2) project was not established until 2006, **IRP, 2007** documents the consideration of issues which lead to contract ratification. **Integrated Resource Plan, 2007** (**IRP, 2007**) could be developed as a continuation of the financial analysis presented in **IRP, 2003**. There are three significant differences which prevent WEC2 from being as cost effective as NC2. First, capital costs have experienced a rapid and unexpected escalation. Second, the NC2 analysis has already claimed the most lucrative displacement of natural gas fired energy; this is recognized with **IRP, 2003** stating that additional base-load generation will not be needed until after 2014. Finally, the natural gas market is experiencing high magnitude price excursions, which make any financial calculations unreliable.

The concern of **IRP, 2007** is the fine-tuning of a planning window, in contrast to **IRP, 2003** which considered acquisition of base-load resources and **IRP, 2001's** concern with satisfying an impending capacity deficit. **(IRP, 2001** and **IRP, 2003** are included as Appendix A of this IRP.) These studies provide many of the considerations which remain applicable to determining feasibility of Whelan Energy Center #2; for the most part, their contents will not be duplicated here.

Source Options: A municipal utility, the Grand Island Electric Department assumes direct responsibility for capacity arrangements. The existing capacity is City owned and locally installed. The ability to incrementally size expansions has resulted in Grand Island participating in jointly owned or shared generation.

Whelan Energy Center Unit 2 is a relatively local generating addition being constructed and available for participation during a time period most closely matching Grand Island's needs. It is the only unit with these attributes of which Grand Island is aware.

The option to which Whelan Energy Center Unit 2 is being compared is existing natural gas fired steam generation installed at Burdick Station. Considerations include: planning horizon, natural gas availability, fuel cost, net capacity cost, source diversity, and fuel diversity.

Critique of IRP, 2001: **IRP, 2001** was prepared because the Electric Department needed additional capacity. The recommendation was combustion turbines, installed at Burdick Station. Annual debt service was estimated at $5,080,000, actual debt service is nearly $6,000,000.

Like the Burdick Station steam generation, the combustion turbines are fueled by natural gas. Unlike steam generation, combustion turbines are designed for intermittent operation. The IRP estimated inability to cycle Burdick Station would reduce potential output of the much lower cost Platte Generating Station by 57,173 MWh annually, beginning in 2008. Based on an estimated fuel cost difference of $48/MWh, operating the combustion turbines rather than steam generation would result in an annual savings of $2.7 million, beginning in 2008 and would remain nearly constant after that date. Application of fuel savings to the annual debt service results in a low cost capacity acquisition.

The corresponding energy savings have been determined for 2005 and 2006 by examination of operating records. Although the energy savings are a fraction of the 57,173 MWh projected to be reached by 2008, the cost difference has increased to $85/MWh. Savings are as follow:

Year	Energy	Value
2005	14,364 MWh	$1,229,940
2006	15,528 MWh	$1,319,880

Savings Realized by Not Operating Burdick Steam Unit Off-Peak

In **IRP, 2001** values were not assigned to the "quick start" and "black start" capabilities of the combustion turbines. Both features facilitate purchase of non-firm economy energy from the regional market. "Quick start" allows a purchase to be maximized. Once Platte Generating Station (PGS) reaches maximum generation, supplemental energy is purchased. The combustion turbines are started only when purchased power is unavailable or uneconomical.

"Black start" enables self-recovery from a system black out. During PGS maintenance outages, 100% of replacement energy is purchased at a cost much lower than operating Burdick Station gas fired steam generation. With "quick start" and "black start" capabilities, there is not a pressing for need for local production. In 2001, financial value of "quick start" and "black start" was speculative; because of a conservative perspective, the resulting potential savings were intentionally omitted from the analysis.

The value of purchased energy can now be compared to energy produced from the combustion turbines. The figures are from Power Cost Adjustment (Appendix B) totals for 2005 and 2006.

Year	CT Production	CT Fuel Cost	CT Cost
2005	8,426 MWh	$1,263,811	$150/MWh
2006	11,456 MWh	$1,316,233	$115/MWh

Approximation of Combustion Turbine Energy Cost

Due to light loading and infrequent operation of the combustion turbines the fuel costs are higher than would have been achieved with continuous operation at an optimum output, the result is approximately a 5% overstatement of savings.

Year	Purchased Energy	Purchased Cost	Purchased Price
2005	48,432 MWh	$3,298,503	$68/MWh
2006	42,571 MWh	$2,219,157	$52/MWh

Calculation of Average Non-Firm Purchase Power Cost

Year	Purchased Energy	Cost Difference	Savings
2005	48,432 MWh	$82/MWh	$4,004,224
2006	42,571 MWh	$63/MWh	$2,681,973

Calculation of Savings through Non-Firm Power Purchases

Compared with operating Burdick steam generation, installation of the combustion turbines has saved the following:

Year	Savings from avoiding operation of Burdick steam units	Savings from purchases rather than operating CTs.	Total Savings
2005	$1,229,940	$4,004,224	**$5,234,164**
2006	$1,319,880	$2,681,973	**$4,001,853**

Total Energy Cost Savings Realized by the Combustion Turbines

In **IRP, 2001**, only the avoidance savings were considered, these were expected to be maximized at $2.7 million in 2008. Savings from the purchase of non-firm energy were uncertain and intentionally not included in the financial analysis, in order to provide a conservative financial picture. The combustion turbines more are cost effective capacity additions than originally presented in **IRP, 2001**. The average 2005 and 2006 savings of $4.6 million offsets the annual bond payments of nearly $6 million, making this necessary capacity addition an extremely low cost capital investment.

<u>Whelan Energy Center #2</u>: Public Power Generating Agency (PPGA) is the developer and owner of Whelan Energy Center Unit #2. PPGA is comprised of five public utilities: Grand Island Utilities, Hastings Utilities, Nebraska City Utilities, Municipal Energy Agency of Nebraska, and Heartland Consumers Power District of Madison, SD.

WEC2 will be a nominally rated 220 MW pulverized coal-fired sub-critical generating unit fueled with low-sulfur coal. The total estimated construction cost of WEC2, including transmission, rail car storage, and other facilities is $469,000,000. Commercial operation is expected to begin in February 2011.

WEC2 will be located adjacent to an existing 77 MW coal-fired generation facility, known as Whelan Energy Center Unit #1, located on the former Naval Ammunition Depot three miles east of Hastings, Nebraska. Whelan Energy Center Unit #1 is owned and operated by Hastings Utilities. There will be land lease and joint facilities use agreements between Hastings Utilities and PPGA. PPGA will contract with Hastings Utilities to manage, operate, and maintain WEC2.

In addition to the normal environmental permitting, pre-application ambient air monitoring was performed. Once WEC2 becomes operational, it will be used for groundwater remediation. Volatile organic compounds from the former Ammunition Depot will be removed through aeration in the WEC2 cooling tower.

Grand Island has a 6.82% participation in WEC2, which equates to 15 MW of capacity. Grand Island's share of debt service is expected to be approximately $2,250,000. With a representative cost differential between WEC2 energy and Burdick Station gas-fired energy of $90/MWh, the economic breakeven point comes once WEC2 produces 25,000 MWh of energy which would otherwise have been produced from natural gas at Burdick Station.

Participation in WEC2 provides increased source diversity, slightly increasing reliability while simplifying maintenance scheduling. Platte Generating Station (PGS) and NC2 each can be expected to have, at minimum, 7 day scheduled maintenance outages in the spring and fall. During these periods, WEC2 will be fully utilized to provide a replacement of 10,000 MWh of coal-fired generation.

Also scheduled at PGS are major inspections and overhauls at three and five year intervals; these outages are generally from four to eight weeks in duration. Major maintenance outages at PGS further decrease the WEC2's financial breakeven threshold.

Load Projections and Resources

<u>Load Projections</u>: The Electric Department makes monthly projections of demand and energy requirements. A time series, beginning in 1978 is used. Results are graphically displayed, in order to identify anomalies which may evolve into trends. These graphs are included as Appendix C.

For purposes of this report, the following years are of the most interest:

Year	Summer Peak Demand	Winter Peak Demand
2011	187 MW	122 MW
2012	191 MW	126 MW
2013	196 MW	129 MW
2014	200 MW	133 MW
2015	205 MW	137 MW
2016	210 MW	141 MW
2017	215 MW	144 MW
2018	220 MW	148 MW
2019	225 MW	153 MW
2020	230 MW	157 MW

<u>Resources</u>:

Location	Unit	Type	Capacity	Fuel
Platte	1	steam	100 MW	coal
Burdick	GT-1	CT	13 MW	NG / #2 oil
Burdick	GT-2	CT	34 MW	NG / #2 oil
Burdick	GT-3	CT	34 MW	NG / #2 oil
Burdick	1	steam	16 MW	NG / #6 oil
Burdick	2	steam	22 MW	NG / #6 oil
Burdick	3	steam	54 MW	NG / #6 oil
Nebraska City	2	steam	33 MW	coal (2009)
Whelan	2	steam	15 MW	coal (2011)
WAPA		Firm Purchase	9 MW	

Capacities are accredited summer capacities. The WAPA purchase varies hourly, closely following the spinning reserve requirement; in the planning process the WAPA capacity is considered spinning reserve and not explicitly shown.

Capacity from coal steam units and combustion turbines in 2009 is 210 MW.
Capacity from coal steam units and combustion turbines in 2011 is 225 MW.
Coal fired steam generation and combustion turbines will serve load through 2019.

Public Input

Local Level: Grand Island operates under a Mayor - Council form of government. Formal public secessions are conducted twice monthly. In addition there are frequent planning sessions, open to the public, during which no formal action may be taken. Meetings are advertised and reported by the local news media. Proceedings are also broadcast on low power City television, with cable TV access.

Public consideration of the selection of WEC2 for future base load power supply, by the Grand Island City Council, resulted in the following resolutions:

July 10, 2001	Non-disclosure Agreement
September 11, 2001	Financial Commitment Agreement
January 28, 2003	Renew Non-disclosure agreement
April 13, 2004	Increased Financial Commitment Agreement
August 9, 2005	PPGA Participation Agreement
September 13, 2005	Assignment of representative to PPGA
October 11, 2005	Assignment of alternate representative to PPGA
November 14, 2006	Amended and Restated Participation Agreement

These resolutions are included as Appendix D.

Nebraska Power Review Board: On December 3, 2004 the Nebraska Power Review Board (PRB), after a public hearing, voted to approve the application for authority to construct the 220 megawatt coal-fired generation facility. The Board concluded that evidence showed the facility will serve the public convenience and necessity, the applicants can most economically and feasibly supply the electric service resulting from the proposed facility, and the proposed facility will not unnecessarily duplicate other facilities or operations.

Condition Certain: In response to the Energy Policy Act of 1992, the Unicameral, in 1996, directed study of the Nebraska electric utility industry and the possibility of implementing retail competition. The study directed by Legislative Resolution 455 was completed in 2000. Rather than adopt a "time certain" implementation of retail competition, the report recommended a "condition certain" approach. On April 11, 2000, this approach was formalized as Legislative Bill 901. In order to protect consumers, five preconditions must exist before retail competition is considered. One of these preconditions is the ability of Nebraska to produce wholesale electric power at a cost which is less than the costs prevailing in the region.

One of the duties of the Nebraska Power Review Board is to have prepared an annual "Condition Certain" Report. The reports are available at www.nprb.state.ne.us.

A finding in the 2006 report is that wholesale Nebraska prices for the 2003-2006 study period are 39.6 percent below the regional market. The power industry in Nebraska has a strong interest in maintaining competitive electric costs. A competitive position is achieved through large efficient and fully loaded generating plants. Participants exchange the pride of individual plant ownership for the cost efficiencies achieved through cooperation.

Joint Planning

Local Planning: With saturation of residential air conditioning in the mid-1970's, the electric industry appears to have reached maturity. Growth of electrical demand in Grand Island dropped from nearly 9% annually to slightly over 2%. Other utilities have experienced similar changes. With a 9% growth, electric demand doubles every 8 years; with a 2.2% growth, demand takes 31 years to double. This has created an immense change in the supply side planning process.

During periods of 9% growth, the simplified traditional expansion sequence for Grand Island consisted of the following steps:

1. Peak demand approaches generating capacity.
2. Install new generator equaling peak demand & doubling generating capacity.
3. New generator becomes primary source.
4. Old generation is secondary source, primarily used for peaking.
5. Serve growing load for eight years.
6. Return to step 1.

Under this sequence there was a constant pressure to meet growing demand by adding new generation. The capital investment saw a rapid return and the primary sources were relatively new. As units aged, their capacity became less significant, and they could be decommissioned without severe financial strain.

Now that it takes 30 years for electrical demand to double, the traditional expansion sequence is no longer cost effective. Thirty years is an exceptionally long period for a capital investment to gain full utilization. Economies of scale would be lost if small base-load generation was added. With a thirty year expansion cycle, extreme age will create reliability problems from secondary generation. Compared to system demand, ageing generation will be of significant size and difficult to decommission.

Participating in base-load generating units, in part, solves most of these problems. In order to effectively participate in base-load generation, Grand Island needs to adjust its capacity resources with respect to load projections so that Grand Island's need is temporally coincidental with the needs of other of the region's electric utilities.

Transmission: Historically, electric utilities developed locally. Isolated systems required substantial generating reserves to provide reliable service. By interconnecting with each other, utilities were able to share reserves and achieve other economies through power interchanges.

Prior to 1960, Grand Island was an isolated utility. The original interconnection, with NPPD's predecessor organization, was at 34.5kV. During this rapid growth period, this interconnection soon became inadequate. In 1970, a 115kV interconnection provided approximately 10 times the capacity than was available at 34.5kV. Today, the city has four interconnections at three substations. A fifth interconnection, to a fourth substation, is planned.

Before extensive interconnections were established, power outages were local and likely received little national publicity. The major 1965 northeast power outage exposed weakness with poorly planned and executed interconnections. As a result reliability organizations were formed, increasingly assuming more authority. Enforceable Compliance Standards have been established.

Computer modeling has greatly improved transmission security. Before generation additions are approved, the owners are required to correct resulting deficiencies in the transmission system. Use of the transmission system and outages on the system must be scheduled, models perform tests to determine these events can safely occur. The result is a mature and, considering its complexity, stable transmission system.

Joint Planning: The Nebraska Power Association (NPA, www.nepower.org) was formed in 1980 to address industry-wide concerns and interests. In July 2003 NPA filed a **Statewide Coordinated Long Range Power Supply Plan** with the Nebraska Power Review Board. Copies of this plan can be found on the PRB and NPA web sites. An updated Load and Capability Report is available on the NPA web site.

Utilizing NPA efforts, Grand Island has attempted to determine when other utilities may need meet growth by additional base-load generation.

Utility	Capacity Need Date
Lincoln Electric System	2013
Omaha Public Power District	2017
Fremont Utilities	2018
MEAN	2018
Hastings Utilities	2019
Nebraska Public Power District	2022

Participation in WEC2 postpones Grand Island's need for more base-load generation from 2016 to 2019. The planning window now is in better agreement with the needs of other utilities.

During the initial years of participation in WEC2, there will be insufficient displacement of natural gas energy by coal energy for the cost difference to make the capital payment for the coal-fired capacity. But by, 2018, participation in WEC2 produces nearly an ideal generation mix for Grand Island; the projected winter peak demand is 148 MW, which is the total of base-load coal generation. Coal generation will be well matched to the load for the entire year, with combustion turbines utilized only for summer peaking duty.

Wind Turbines: Located near a staging area for migratory waterfowl, Grand Island is unable to locally install wind generation as a renewable resource. NPPD has constructed two wind turbine installations and extended participation invitations to other utilities. Grand Island is a participant in each facility.

Due to a legislative concern over cost and duplication of facilities, there is little wind generation in the State. The legislative environment is becoming more receptive to renewable resources, so installation of more wind generation can be expected. Grand Island intends to further participate in wind energy.

IRP Performance Evaluation: A delay in WEC2 construction will not have a significant impact on Grand Island. The major activity is monthly monitoring of Grand Island's load projections to ensure unexpected trends are not developing.

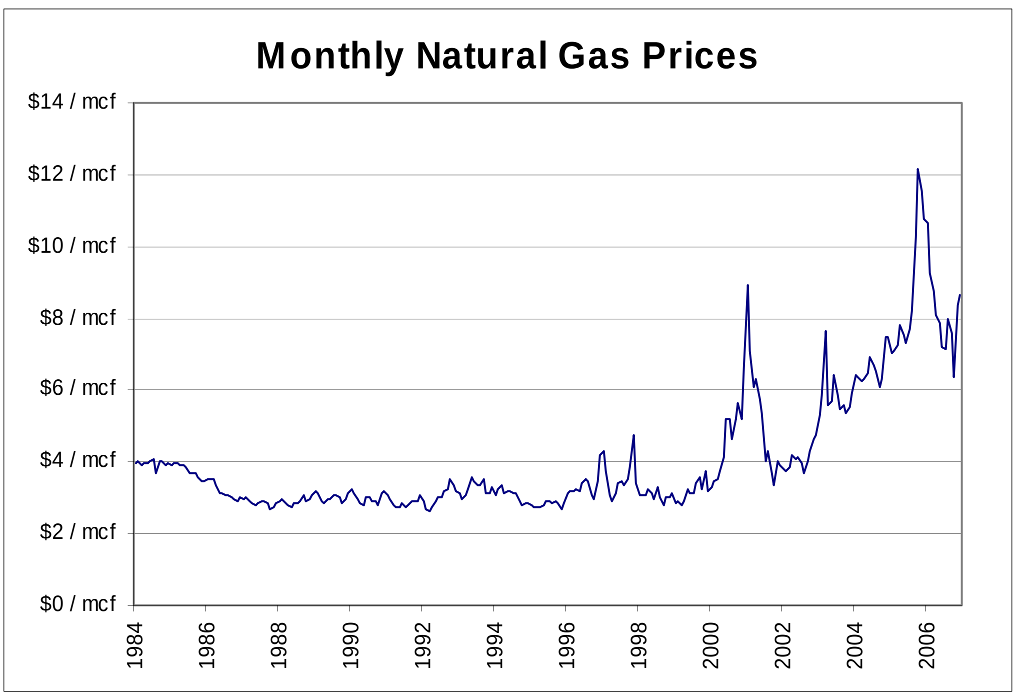
Natural Gas

Availability: Grand Island remains reluctant to rely excessively on generation fueled by natural gas. {For an understanding of the historical experience, please refer to pages 7, 8, & 9 of **IRP, 2003** (Part #1) in Appendix A.} Participation in WEC2 delays the need to operate the Burdick Station steam generation, until after 2019. It is the intent to continue to operate the combustion turbines on natural gas for peaking service, during high demand intervals.

One of the main reasons for selecting combustion turbines in **IRP, 2001** was to reduce natural gas consumption, from what would be needed if the Burdick steam generation was utilized. Gas-fired generation is now run only for peaking, when non-firm electrical energy is unavailable for purchase.

An impending problem exists; with the installation of GT-2 and GT-3 in addition to GT-1 and the old steam units, the potential demand for natural gas has increased by 65%. Production capability at Burdick Station was 105 MW prior to the combustion turbine addition, with the two new combustion turbines it is 173 MW. The capability of delivering these volumes of natural gas remains untested.

Pricing: The Energy Information Administration (www.eia.doe.gov) maintains records on natural gas pricing. The following graph displays monthly wholesale prices:

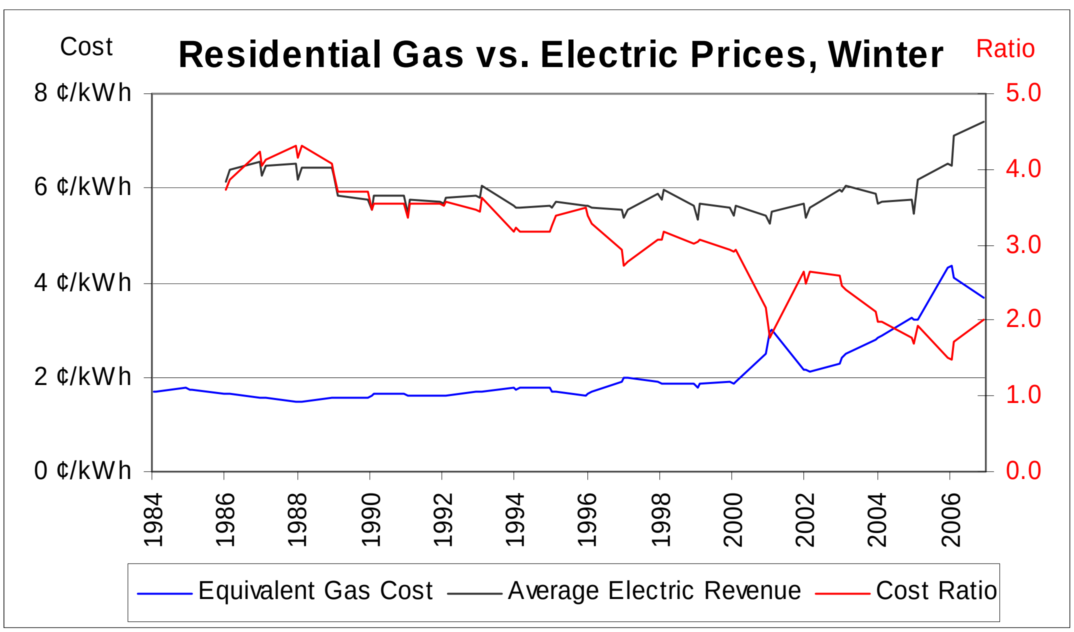


The hourly price of natural gas is more volatile than the monthly presentation indicates. During most months, one can expect wholesale gas commodity pricing to range between $4/mmBTU and $8/mmBTU. In the past two years, prices have varied from under $4/mmBTU to over $14/mmBTU. If gas consumption were constant, cost averaging would closely resemble monthly averages. However, the infrequent use of the combustion turbines results in a non-representative sample of gas prices and leads to unpredictable economies.

Price Spiral: Amongst the volatility, there is an underlying trend of increasing price. This appears somewhere between 6% and 8% annually. Each year Grand Island will increasingly use gas fired combustion turbines for peaking duty, creating a multiplicative effect.

Grand Island's planning avoids operating Burdick steam generation and restricts natural gas consumption to combustion turbine peaking duty. Between 2011 and 2016, WEC2 participation will displace natural gas derived energy which would otherwise be produced from Grand Island's combustion turbines. Natural gas prices are too volatile to quantify this value, but it may help to reduce the affects of a price spiral.

Electric Heat: The EIA web site contains prices for residential gas consumption. Two decades ago, electricity was four times as expensive as natural gas, now it is only twice as expensive. With natural gas prices approaching the cost of electricity, consumers will increasingly utilize electric heat. If the winter peak demand approaches the summer peak, combustion turbines will need to be used to furnish peaking energy for short durations.



Grand Island has potential to become a strong winter peaking utility; this would create the need for additional base load generation. The resulting investment in generating plant could cause retail electric rates to jump dramatically. Winter consumption must be monitored and actions taken to prevent unexpected heating load from producing disastrous financial consequences.

Energy Markets

Joint Marketing: As is apparent in the **Critique of IRP, 2001** section, Grand Island routinely purchases energy when economically advantageous. In a similar manner, sales are also made. These interchanges are strictly a means of reducing costs to customers and not an attempt to enter any wholesale market. The purchase and sales quantities are too small to justify internal marketing expertise. NPPD acts as Grand Island's sole marketing agent, through a Joint Marketing Agreement executed in 2000.

Grand Island is a price taker, exercising no control over energy prices. Variations in hourly pricing are of little concern; Grand Island's responsibility is to ensure interchange activities reduce the overall price to its retail customers. Sales are made from excess production capacity from PGS, generally off-peak. There appears to be a $21 / MWh margin between Grand Island's fuel cost and the offered price. This is an average margin; during actual transactions, price can vary hourly.

Purchases are made once PGS is operating near its peak output and other utilities have energy for sale, which in all likelihood is not produced using natural gas. The annual price averages indicate that Grand Island purchases energy for 45% of what it would cost to produce from the combustion turbines. Grand Island has not performed a detailed investigation as to the origin of the ratio; it may be coincidental, natural gas prices may be driving purchased energy prices, or electric energy prices may be driving natural gas prices.

The following table provides the values from which the margins and ratios were calculated. It must be emphasized that the calculated quantities are illustrative only, the apparent consistency between years lacks a fundamental basis determination.

Year	2005	2006
PGS fuel cost	$11 / MWh	$13 / MWh
Non-Firm Sales	$32 / MWh	$34 / MWh
Average margin	**$21 / MWh**	**$21 / MWh**
CT fuel cost	$150 / MWh	$115 / MWh
Non-Firm Purchases	$68 /MWh	$52 / MWh
Purchase to CT on natural gas ratio	**0.45**	**0.45**

Summary of Purchase and Sales Results

Marketing from WEC2: Grand Island is participating in WEC2 because it is the resource which most closely matches needs. By 2016, WEC2 is projected to be integrated to the degree that coal vs. natural gas fuel savings pays the capacity charge resulting from the

PPGA bond issue. However, with the volatility and uncertainty of natural gas pricing, a precise determination is unlikely.

To determine the impact of WEC2 on the City's ability to service Grand Island's share of the PPGA debt, an illustrative worst case will be assumed. That is: Grand Island has insufficient load to utilize any of the WEC2 output and all of Grand Island's allotment is offered on the market.

From experience with PGS, WEC2 should be on-line approximately 49 weeks of the year. Our marketing experience indicates power can readily be sold for at least 16 hours per day. With 15 MW of participation, 82,320 MWh could potentially be sold. Removing $4 / MWh of non-fuel O&M costs from the $21 / MWh margin, results in a net margin of $17 MWh. Income from energy sales could reach $1.4 million. With a projected annual capacity charge of $2,250, 000, the net cost to the Electric Department would not exceed $850,000. The F.Y. 2005-06 net income for the Electric Department was $40 million, putting the worst case net cost at approximately 2% of income.

Fuel Diversity

EPAct 2005: The Energy Policy Act of 2005 encourages electric utilities to minimize dependence on a single fuel source and produce electricity utilizing a diverse mixture of fuels and technologies. Generation plant is the greatest physical impediment in fuel switching, over which an electric utility has control. Issues such as permitting, transportation, and availability are generally beyond the control of individual electric utilities and may be shorter lead time than plant acquisition.

This IRP considers the period between 2011, when WEC2 becomes operational, and 2019, when additional resources will be needed. Grand Island will experience the least diversity in 2019, so 2019 is selected as the year of analysis.

Resources: In 2019 Grand Island will have the following resources, listed by fuel type:

Primary Fuel	Secondary Fuel	Technology	Total Net Rating
coal	none	steam turbine	**148 MW**
natural gas	#2 oil	combustion turbine	**81 MW**
natural gas	#6 oil	steam turbine	**92 MW**

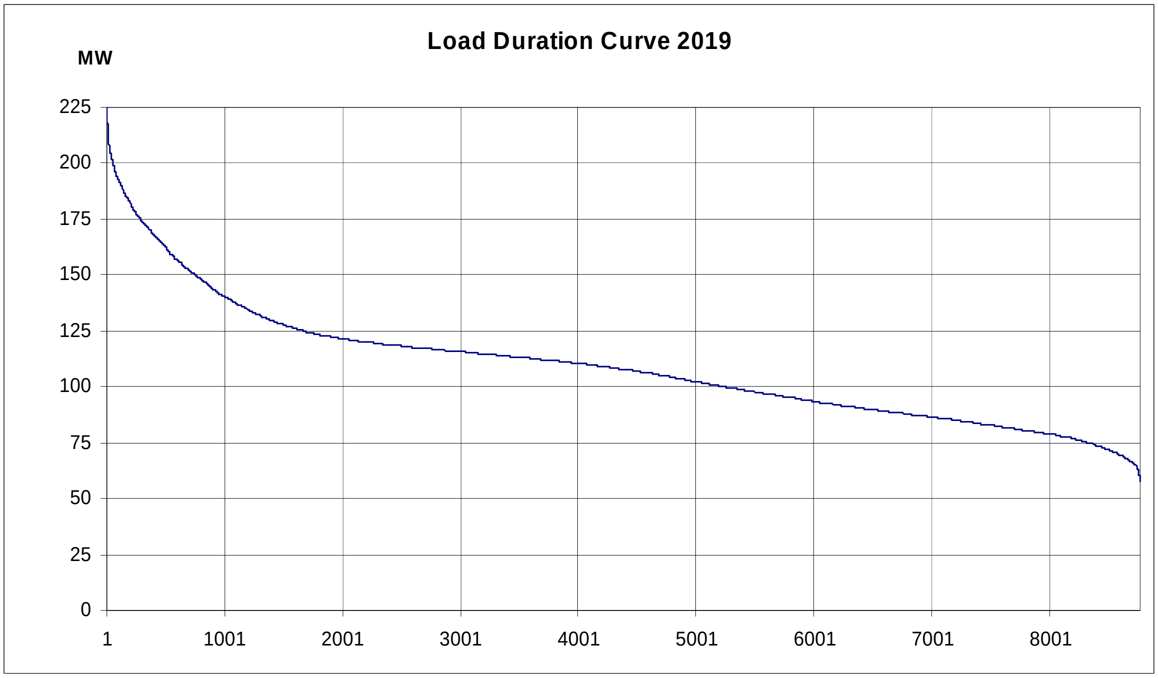
Coal generating capacity, 148 MW, approaches the 173 MW of natural gas / oil capacity. Of natural gas / oil generating units there is a near equal split between #2 oil, 81 MW, and #6 oil, 92 MW.

Load: Resource diversity is near meaningless if all resources are required to serve the load. Grand Island has structured its resource portfolio to neatly fit within various sections of the load duration curve. Maintenance outages are coordinated with neighboring utilities, during shoulder months and are not included in the analysis.

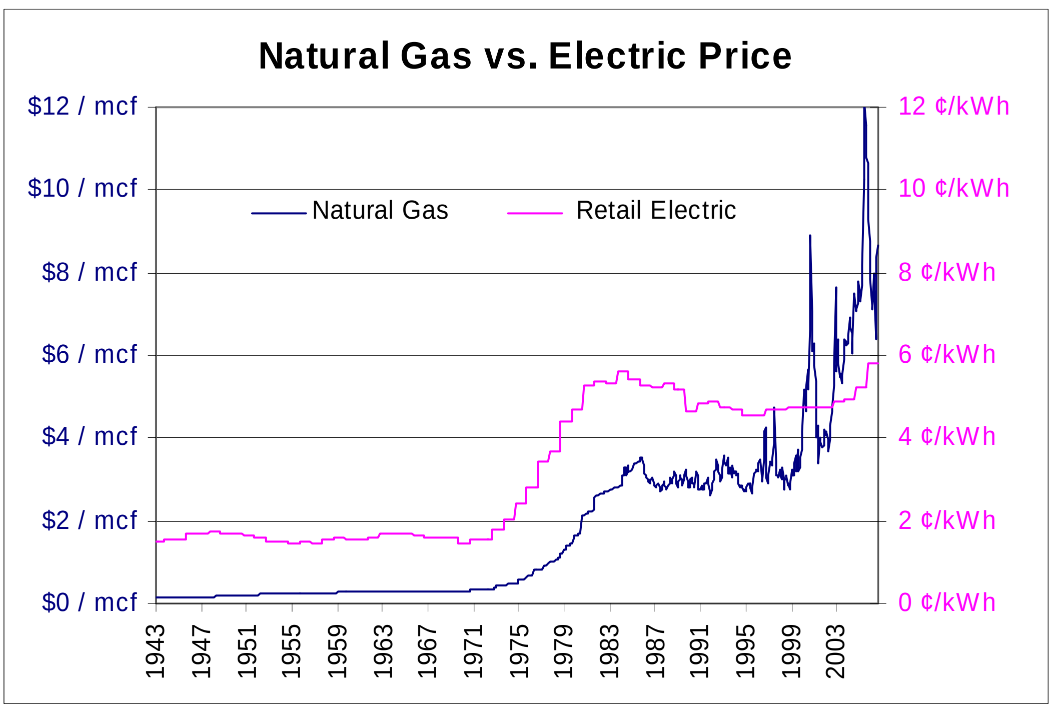
In 2019, the projected summer peak demand is 225 MW. With 148 MW of coal fired generation, natural gas / oil generation is expected to operate fewer than 1,000 hours per year. Combustion turbines are planned to produce the peaking energy, utilizing either natural gas or #2 oil. If neither of these fuels is available, the Burdick Station steam generation can satisfy the peaking demand, using #6 oil.

If coal is unavailable, natural gas / oil generation can fully serve the load for all but 500 hours per year. Only 53 MW of coal generation will be needed during the peaking intervals. Since 48 MW of coal fired energy will come from NC2 and WEC2, it is unlikely that PGS would be operated in an environment of more plentiful fuels.

The following projection of the load duration curve for 2019 serves as a reference for the various blocks of generation.



<u>Financial Benefit</u>: It is instructive to join the historic natural gas price data from **IRP, 2001**with that provided by EIA. These prices can then be compared with Grand Island's average annual retail electric rate.



From 1943 until 1983, Grand Island's generation was dependent upon, low cost, natural gas. Until 1973 the dependency was unquestioned. Fuel oil storage provided a high cost alternative, but during the embargo, oil was difficult to obtain. When natural gas prices began the seemingly unchecked rise, electric rates were forced to follow, more than tripling in a decade.

PGS became operational in December 1982; after switching to coal, electric rates stabilized. Revision of coal and freight contracts resulted in 15% decrease in electric rates. In the early 1980's, the steep increase in natural gas prices paused, then resumed. Electric rates are also increasing, but with fuel diversity provided by coal fired generation, Grand Island's electric costs are less impacted by natural gas prices than they were in the 1970's.

Burdick Station Steam Generation: Firing of #6 fuel oil at Burdick Station must be anticipated. Residual oil is too viscous to flow under ambient temperatures; boiler steam heats the oil, so that it can be pumped through the burner nozzles. Ignition of the boiler flame is performed using natural gas igniters.

Burdick Station steam generation is maintained in cold standby condition, operated annually for accreditation. If the fuel situation begins to appear bleak, propane storage should be considered to facilitate start-up.

Black Start: In the event of a system wide electrical blackout, protective relaying on transmission interconnections is designed to isolate Grand Island. If the city load exceeds the capability of PGS, the combustion turbines require only minutes for the start and warm-up procedure. Using a diesel engine for start-up, GT-1 has full black start capabilities. Once started, the output from GT-1 powers the start-up motors for GT-2 and GT-3. Since switching must be done to remove unwanted load from GT-1 to direct its output to GT-2 and GT-3, local blackout recovery will take approximately an hour.

The combustion turbines can use either natural gas or #2 oil for starting and running. If natural gas pipe line companies are using electric motors to drive compressors, natural gas may not be available during a major power outage. The ability to fire #2 oil in combustion turbines is critical to power system restoration.

NPPD's 230 kV transmission line crosses over Grand Island's 115 kV transmission lines, ½ mile north of Platte Generating Station. During the December 30, 2006 ice storm, the 230 kV line fell across the 115 kV line, damaging both the 115 kV transmission loop and PGS. The combustion turbines at Burdick Station supplied power to Grand Island until January 3, when repairs were complete.

With 81 MW of combustion turbine capacity, essential public welfare and safety facilities along with residential and commercial service can be provide to Grand Island, even in as late as 2019. Controlling use of air conditioning and non-essential power use would be required. Achieving such control could conceivably be addressed when "smart metering" is considered.

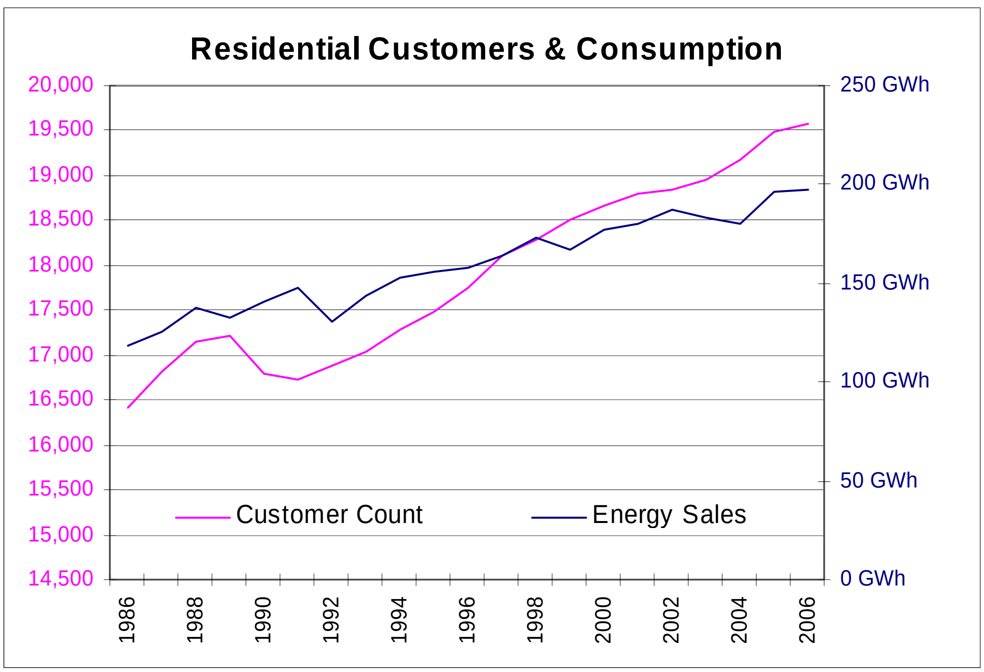
Conservation

Status: The 1996 Integrated Resource plan did not justify utility sponsored conservation programs. Nevertheless, appliance efficiency standards have been in place for sufficient time to be widely adopted.

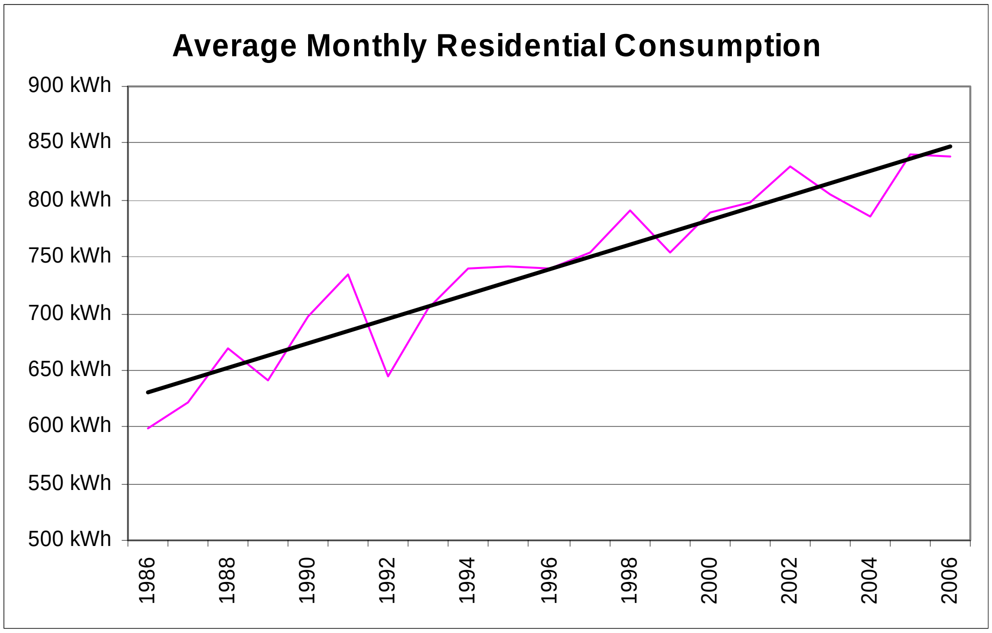
Residential lighting is no longer restricted to the A-type incandescent bulb. With replacement compact fluorescent bulbs and high efficiency low-voltage systems readily available, lighting is primarily a matter of aesthetics.

Residential consumption is sufficiently homogenous so that the impact of energy efficiency can be measured. Between 1986 and 2006, retail sales grew at 2.8% annually, while the residential component grew at an annual rate of 2.4%. The billing months of January and February represent consumption during December and January, the peak winter months. Annual winter growth was 2.5%; an insignificant amount of electric heat is being added; heating load can therefore be ignored at this time.

Residential Consumption:



Residential energy sales grow at 2.4% annually while the customer count grows at 0.88%. To measure the affect of conservation methods, one needs to calculate the per customer consumption, which is growing at an annual rate of 1.5%. On the surface it appears that energy efficient appliances and lighting are increasing energy consumption.



<u>New Home Size</u>: Rather than accept an illogical conclusion with regard to energy efficient appliances, one can start with an assumption that consumers are simply purchasing more appliances. A measure of this possibility can be found from the National Association of Home Builders (www.nahb.org). The average new home size in 2005 was 2,434 square feet, up from 1,645 square feet in 1975; an annual growth rate of 1.3%. Americans simply are constructing more room in which to use energy, canceling efficiency improvements made to individual devices.

This is not surprising. Although lip service is given to conservation, the real concern is the economy. There are near daily news items on gasoline availability, gasoline prices, new home starts, electric adequacy, and electric prices. These are coupled with seasonal concerns with outages, brown outs, and rolling black outs. The electric industry is expected to accommodate affordable consumptive behavior.

<u>Conservation</u>: Even with the above reservations, a decrease in growth rates supports effectiveness of conservation efforts. Peak demand can be considered a valid metric. One can observe that over the years the growth rate decreases and the peak for a given year is less than originally expected.

Source	July 2006 Demand	July Demand Growth Rate
IRP, 2001	174 MW	2.53%
IRP, 2003	171 MW	2.44%
2006 Actual	164 MW	2.32%

Although the growth rate is decreasing, not until it approaches, or falls below, the 0.88% rate of customer additions, will conservation be achieved. Unfortunately, the rate of demand growth decrease is disturbingly slow.

APPENDIX “A”

Grand Island, Nebraska
Electric Department

Integrated Resource Plan, 2003

November 2003

IRP, 2003;   Part #1
Report and Resolution

Background for Integrated Resource Plan, 2003

Integrated Resource Plan, 2001: Grand Island's power needs were last studied in 2001; this study is included as Appendix A. The goal of **Integrated Resource Plan, 2001 (IRP, 2001)** was to secure an additional capacity resource by 2004, while minimizing the consumption of natural gas. As a result, two new combustion turbines are now in service at Burdick Station.

When the **IRP, 2001** was prepared, it was anticipated that capacity needs would be satisfied until 2016. The annual peak demand growth is gradually slowing; it now appears that the existing capacity will be sufficient to meet peak demands until 2018. However, full utilization of this capacity would require sustained operation of the older natural gas fired Burdick Station steam generation, at an excessive cost.

IRP, 2001 recognized that a new source of low cost energy, by 2012, would be beneficial to the Utility's generation mix. Grand Island has been offered the opportunity to participate in a new coal fired generating plant. Participation is in OPPD's (Omaha Public Power District) Nebraska City #2, which is planned to become operational in May 2009.

Integrated Resource Plan, 2003 confirms the need for a low cost energy source by 2012. Being the first with a permit and defined schedule, Nebraska City #2 is the most certain of coal-fired plants under consideration in the State. Nebraska City #2 provides a basis for analysis. The issue is actually a comparison of fuels: coal vs. natural gas. Other coal-fired plants are being discussed and may possess similar cost characteristics; benefits derived from participation also depend upon the level of participation, start-up dates, and the duration of the studied interval. True costs and operational issues are not fully known until after plants become operational. The object of **IRP, 2003** is to select alternatives with a high probability of minimizing production costs.

By the year 2022, all participation under consideration will be required to serve Grand Island's load. Beyond that date, new energy resources will be sought. The best option is to diversify by participating in several plants.

Electric Growth: Generating capacity (measured in MW or megawatts) is installed to satisfy the peak demand. Figure 1 is a graph of Grand Island's peak electrical demand history. Over the term, capacity remains above the demand. It appears that there was little activity in load and generation additions prior to about 1970 and that capacity margins have now become exorbitant. These appearances are illusions, because of the scale of the graphs.

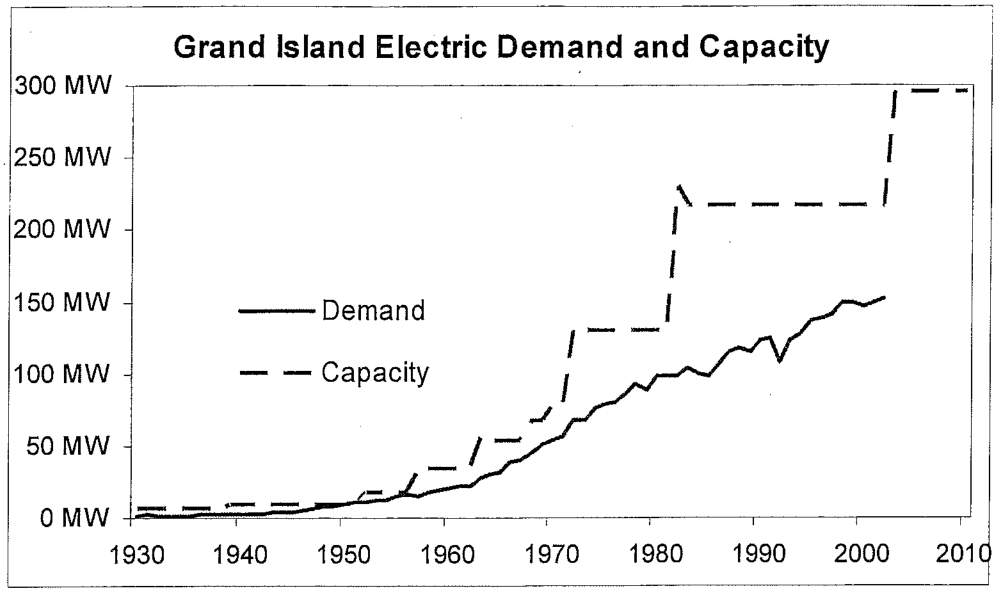


Figure 1

Regardless of their size, electric utilities generally face similar problems and solutions. The major difference between a large utility and a small utility is the number of rate paying customers. The customer of a small utility is just as interested in cost as is one of a large utility. Since the electric demand has grown over time, the small vs. large comparison is also a temporal issue.

To remove the distortion caused by size, a non-linear logarithmic vertical scale is commonly employed. This creates a size independent similarity along the curves.

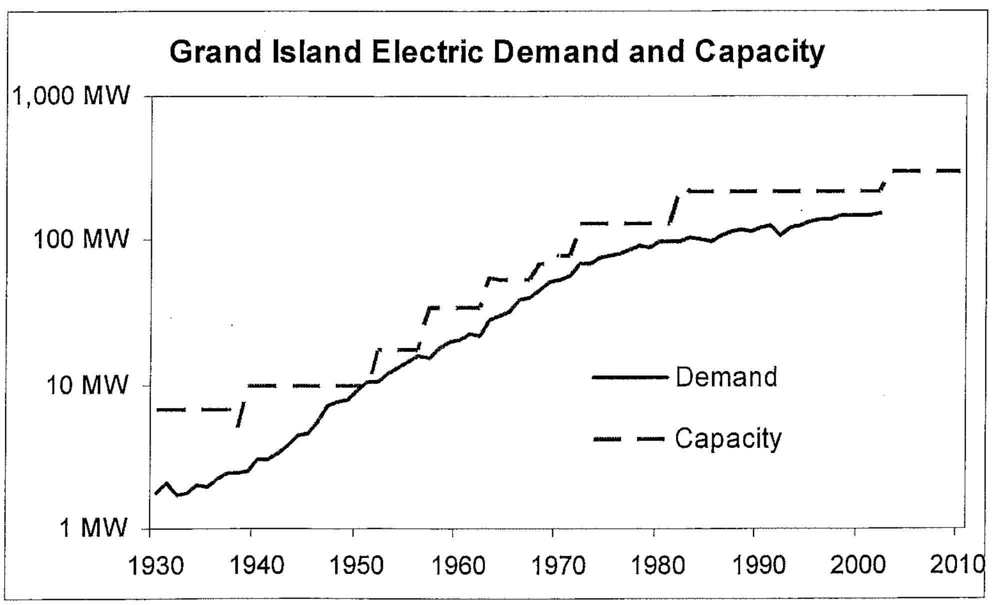


Figure 2

Figure 2 illustrates that the relative difference between generation and peak demand has actually decreased in the later years. After rescaling the vertical axis differences, along the curves, remain. These are best illustrated by splitting the above graph into two 40-year segments. The 1930 to 1970 interval will be referred to as the early period. The 1970 to 2010 interval will be referred to as the mature period. In Figures 3 & 4, growth trend lines are added to the demand curve. Compound growth results in a straight line, when plotted on a logarithmic scale.

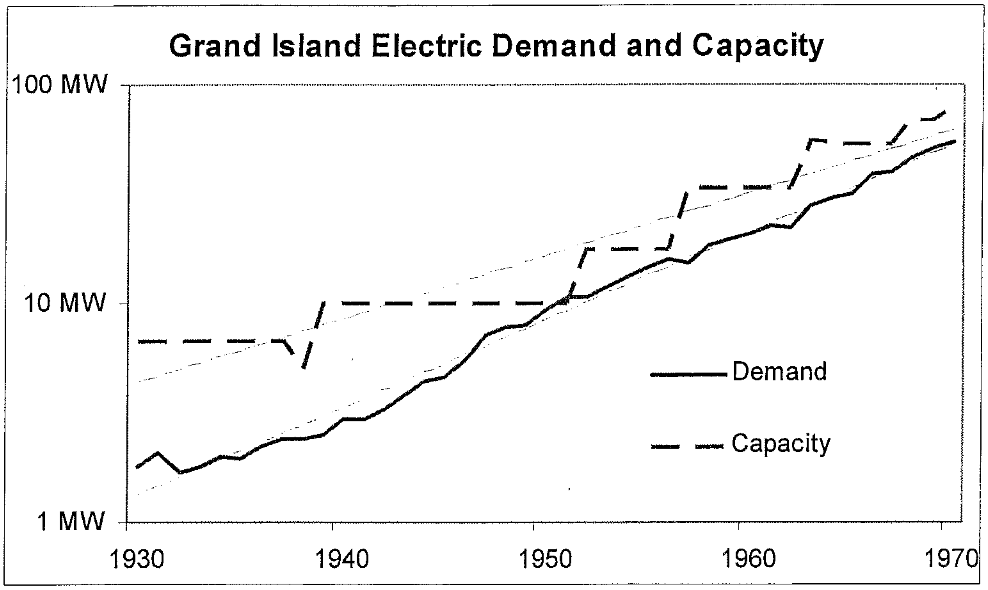


Figure 3

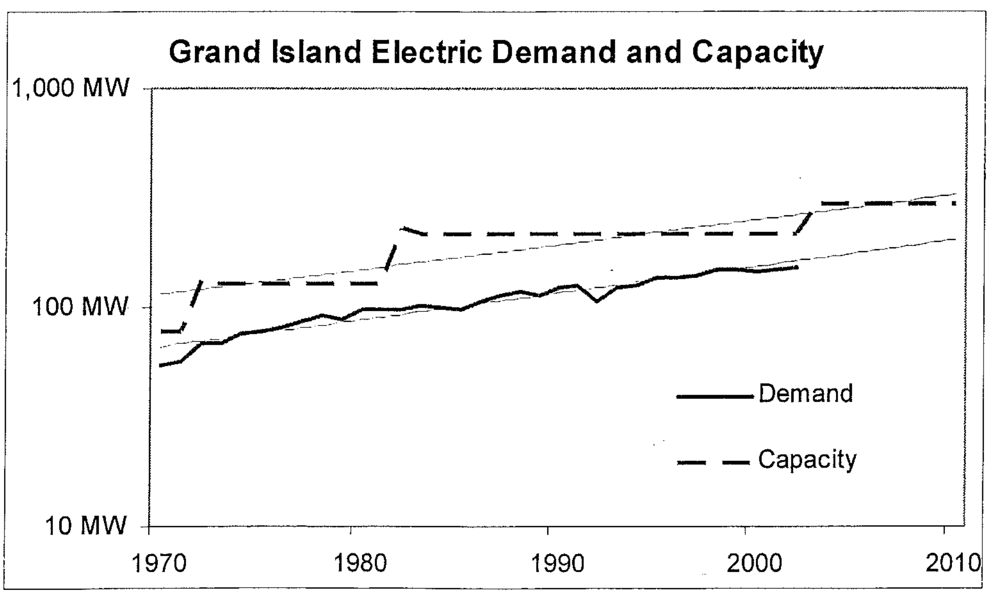


Figure 4

The slope of the demand curve trend line indicates the average annual growth rate. For the early period, this is greater than 9%; for the mature period the growth rate is less than 3%. Five capacity additions were made in the four decade early period. To date, the mature period has required only three additions. Compared to gas-fired generation at Burdick Station, participation in Nebraska City #2 will be a relatively small capacity addition but it is intended to furnish a disproportionately large share of the energy requirements of the City.

Reliability: Electric utilities began in localized population centers. Over the years interconnections were made among the various utilities. Today, the North American electric system is a complex interconnected grid. Grand Island first obtained an electrical interconnection to the national grid in 1959, via the predecessor organization to Nebraska Public Power District (NPPD). The interconnected grid allows utilities to mutually support one another and makes possible purchase of low cost energy from remote locales.

The difference between capacity and demand is the reserve margin. Operating isolated, a utility must have sufficient reserve margin to replace loss of the largest generating unit. Grand Island was, and remains, small enough that a single power plant can serve the entire load. So as a general rule, each generating addition was capable of serving the City load and making it approximately twice the size of the previous unit.

Maintaining 100% excess capacity is an inefficient use of capital. Furthermore, this mode of operation can only adapt to a single contingency; that is loss of a single generating unit. Sharing reserves is a major reason for electric utilities to interconnect. After the interconnection was established in 1959, Grand Island's capacity resources more closely approach the demand curve. The distance between the capacity and demand curves is known as reserve margin.

IRP, 2003 is concerned with evaluating the lowest cost available energy source, rather than a capacity addition. The economic evaluation is based solely on energy costs, with the benefit of additional capacity being ignored. The value of capacity is ignored because the energy benefits are sufficiently great that participation can be justified before new capacity is needed in about 2020. Placing a value on the additional capacity would further strengthen the economics of participation in low cost energy producing plants.

Reserves: Electrically, North America is divided into Interconnection areas. Transmission capabilities across Interconnection boundaries are severely limited. The major interconnections are the Eastern Interconnection and Western Interconnection. The western extreme of Nebraska is in the Western Interconnection but the majority of Nebraska is in the Eastern Interconnection. Converter stations (AC to DC to AC) near Sidney and Scottsbluff help provide both a link and isolation between the two areas.

The Eastern Interconnection is composed of several Reliability Councils. Grand Island falls under the jurisdiction of the Mid-Continent Area Power Pool (MAPP). Grand Island is an Associate Member of MAPP and its generating capacity is accounted for by Joint Reporting with NPPD. Grand Island is required to comply with the Reliability Standards established by MAPP.

Utilities within MAPP pool their reserves, to provide mutual support in the event of a major equipment failure. The Operational Reserves are dynamic; each member utility is required to maintain spinning or readily available reserves sufficient to proportionately share replacement power for the single largest MAPP contingency. Grand Island's Operational Reserve obligation can be expected to be between 5% and 7% of City load.

In the event of a loss contingency, utilities collectively satisfy the deficiency. Operating Reserves are then recalculated and reassigned. This process accommodates the possibility of multiple contingencies. Utilities must retain sufficient capacity to allow continued reassessment and reassignment of Operating Reserves.

In addition to Operating Reserves, MAPP utilities are required to maintain Planning Reserves. Planning Reserves are defined as 15% of peak load demand. The 15% reserve margin, with interconnection obligations, is more flexible and less costly than the 100% reserve margin of an isolated utility.

Transmission: The 85% reduction of the reserves, from largest generating unit size to 15% of demand, comes at a price. A transmission system must be designed, constructed, purchased, maintained, and dispatched. A robust transmission system is expensive. A competitive market can discourage the large capital investment required for transmission, which can result in deficiencies.

The Northeast Blackout of 1965 resulted in the formation of the National Electric Reliability Council (NERC) and the various regional member organizations, including MAPP. Membership in MAPP is voluntary; by being interconnected, utilities accept voluntary compliance with Reliability Council rules and operating procedures.

For the past decade deregulation of the electric industry has resulted in the restructuring of the transmission systems. The concept is to give all entities open and equal transmission access, without paying a multitude of cross boundary tariffs. This has yet to be achieved.

Demand Growth: At a 9% compound growth rate, the demand doubles every eight years. One way to satisfy this growth is to install additional generation every eight years, with each generator twice as large as the previous addition. In the 40-year early period, there were five capacity additions.

During this period the use of electricity became increasing popular. New applications were forthcoming. The final phase was the popularization of central air conditioning; this event was essentially complete by 1975. At the beginning of the mature period, demand growth suddenly dropped to below 3%.

Whether the decrease in demand growth was anticipated, or not, is a moot issue. In the mid-1970's, an Energy Crisis temporally hid the decreased demand trend. A prohibition on the use of natural gas for electric generation forced utilities to install coal fired generation. Platte Generating Station (PGS) achieved commercial operation in 1982; it joined a host of other, recently constructed, coal-fired plants. The result was a fortuitous over abundance of inexpensive energy, which has served to meet load growth for an extended period of time.

There is no longer an oversupply of low cost energy. Utilities must select the most favorable energy alternative in selecting new generation. With a 3% annually compound growth rate, it takes 24 years for the demand to double. Planning is critical. Decisions can not be made for the short term; wrong decisions will have a sustained impact. Construction activities now appear to be clustered around 20-year windows. Propitious opportunities must be grasped.

Natural Gas

Gas Supply: **IRP, 2003** evaluates participation in Nebraska City #2 through energy production cost comparisons, alone. An additional concern is the uncertainty of the fuel supply to Burdick Station. Electric utilities were essential customers for the growth and profitability of the initial natural gas pipelines. Once the residential natural gas market was established, demand increased and in the 1970's a prohibition on the use of natural gas for electric generation was enacted. By the late 1980's industrial use prohibitions, removal of price controls, increased drilling, and other factors restored availability of natural gas, resulting in new gas-fired electric generation again being built. Eventually, the use of natural gas for electric generation may again be curtailed.

Space heating is a major residential and commercial use of natural gas. At the current load demand, the Grand Island Electric Department uses little natural gas in the winter months. Most usage is for summer peaking generation, when there is less competition from non-utility natural gas customers. Residential and commercial customers, with fewer fuel choices than electric utilities, are assigned a higher priority for natural gas. As gas demand increases, during the winter, large quantities of natural gas may not be available for electrical generation. Load projections show that Grand Island's coal-fired power plant Platte Generating Station (PGS) will soon be fully loaded during each month of the year. In the absence of additional coal-fired generation the Electric Department will be forced to rely on the uncertain winter availability of natural gas.

Relative Fuel Costs: The premise for **Integrated Resource Plan, 2003** is: "The cost of coal (per unit of heat content) will continue to be substantially less than the cost of natural gas." The cost based feasibility of participation rests entirely on substantiating this fuel cost comparison. In fact, the relative price of natural gas does not even need to increase to justify coal-fired generation; this study maintains the present cost differential between coal and natural gas.

Natural Gas: **IRP, 2003** evaluates the economic substitution of fuels &/or energy sources. In the early period the fuel selection was limited to coal and oil. Internal combustion generation used oil; boilers could switch between oil and coal. The least expensive fuel was the fuel of choice. If a fuel became uncompetitive, within eight years, new generation utilizing the more economical fuel, would be installed.

In about 1943 a natural gas pipeline arrived at Grand Island. Natural gas was originally a waste product of the oil industry and the commodity was priced accordingly. Lacking historical customer base development, there was no natural gas distribution system to serve small customers. Large, easy to serve, customers were necessary to pay for the pipeline. The Electric Department was one of these early customers.

Natural gas was the least expensive and remains the cleanest burning of fuels. For nearly four decades, all new generation was designed to fire natural gas as a primary fuel; oil was a rarely used alternative fuel. The population benefited immensely from a stable source of low cost electricity. For decades the price was less than 2¢/kWh. The older gas-fired steam generation at Burdick Station was designed and constructed to produce this low cost energy.

As gas distribution systems grew, natural gas displaced oil and coal for residential and business use. By 1960 the conversion to natural gas was essentially complete. Electric utilities were competing with other users in the natural gas market. Federally regulated, prices remained artificially low. New sources were not developed, resulting in curtailments, restrictions, and eventually deregulation. A rapid price escalation began in about 1976 and continued well into the 1980's. By then Grand Island was a sparing user of natural gas.

The following graph ends in 1985; this was the date when our natural gas supplier stopped furnishing gas at a fixed price. Grand Island now purchases gas on the chaotic spot market. In 2003, Grand Island has seen natural gas prices ranging from $5/mmBTU to $10/mmBTU, with most of the consumption around $6/mmBTU. This compares to a coal price of $0.75/mmBTU. With increased prices and volatility, non-utility natural gas users are again lobbying for restrictions on gas use by electric utilities. One such lobby group is the Industrial Energy Consumers of America.

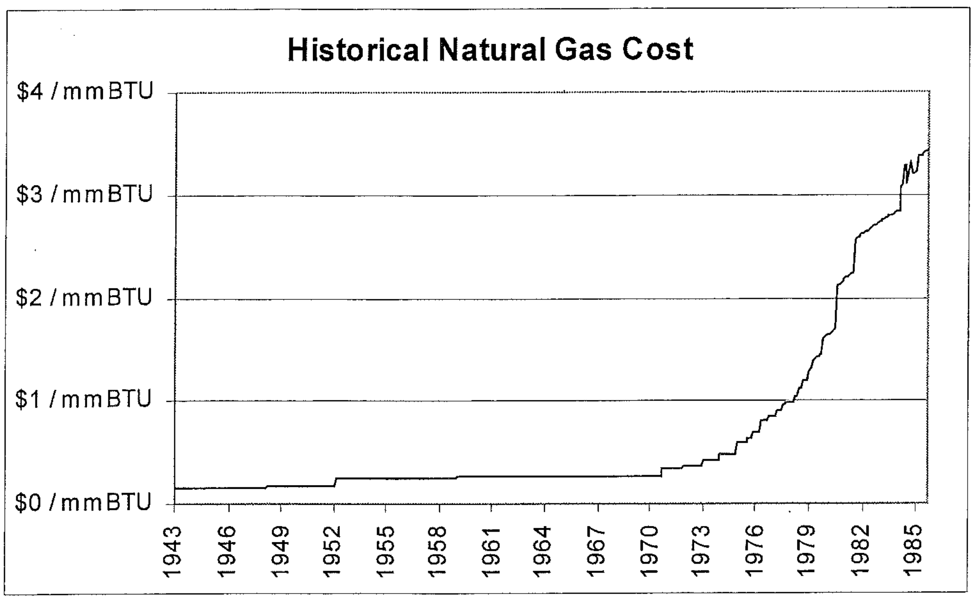


Figure 5

<u>The 1970's</u>: Unit #3 at Burdick Station became operational in 1972. In 1973 Kansas-Nebraska Natural Gas Company informed the Electric Department that they were curtailing use of the commodity. At that time, the cost of natural gas was less than half the cost of fuel oil. Consuming about 25% of the annual electric utility budget, fuel is the single greatest expense. To maintain solvency, the Electric Department implemented a Fuel Adjustment provision to its electric rate schedule in 1974.

The curtailment became an abandonment attempt, impacting many of Nebraska's electric utilities. With the Arab Oil Embargo of 1974 fuel availability became precarious. The Federal Government then deregulated the natural gas industry. The Fuel Use Act of 1978 banned new gas fired power plants, required utilities to comply with a schedule for decreased natural gas consumption, and dictated that natural gas no longer be used for the production of electricity by 1990. In the 1970's the future looked bleak. Since that time the industry has matured. Natural gas again can be used for electric generation, but this premium fuel carries a premium price.

<u>Generation Trends</u>: Neighboring utilities confronted the same problems. Coal-fired plants were the most appropriate solution to fuel restrictions. In the early 1980's, nearly all utilities constructed coal-fired plants, creating an over supply of base load coal units. More recently other utilities performed analysis similar to **Integrated Resource Plan, 2001**. Natural gas fired combustion turbines and combined cycle generation were added to meet increasing peak demands. This creates an additional demand for natural gas. However, this natural gas usage is less than it would have been if utilities placed more reliance on older, existing, gas-fired steam generation which are designed for base load service.

<u>The Gas Market</u>: Originally, natural gas was priced to compete with coal in power plants. As gas distribution systems developed, natural gas displaced coal and oil for commercial and residential use. With a residential market, the price of natural gas increased while the availability to utilities decreased. Coal has now displaced natural gas for base load generation.

For energy applications, electricity and natural gas are interchangeable. Substitution requires a capital investment by the consumer. This creates inertia in the elasticity property, relating price to consumption. Because the required investment to change energy sources acts as a barrier, the incumbent product can be overpriced for an extended period, without significant danger of losing the market. Price volatility of natural gas also clouds the true picture and slows the potential transition from natural gas to electric heat.

From industry reports, pipelines and wells appear to be operating at or near capacity. Boosting the price of natural gas will slow demand, postpone the need for capital investment, and extend the life of reserves, while increasing profits. However, there is a limit to the amount that natural gas prices can be increased, and the price of electricity will be a major factor in the eventual market sustainable price of natural gas.

Electric Pricing and Natural Gas

<u>Electric Heat</u>: From the pricing of residential gas, there appears to be indifference about competing with electricity. The two forms of energy have nearly identical prices.

The commodities are completely dissimilar. Electricity is pure energy while natural gas is a chemical, which must be converted to energy. The production process is much more involved for electricity than is the pumping and piping of natural gas. Yet the two products arrive at the customers' energy meters priced within a few cents of each other. It is difficult to accept that the price similarity is entirely coincidental.

If consumers switch to electric heat, the need for more electric generating capacity will cause the cost of electricity to gradually increase. This will permit a parallel increase in the price of natural gas. The limiting factor, to natural gas pricing, is the ultimate cost of electricity. To determine this, one can anticipate the cost of electricity, should all customers immediately switch from natural gas heat to electric heat.

In this analysis, approximate numbers will be used, so the reader can follow the thought process more readily. Precision is unimportant; the goal is to grasp what may be happening in the natural gas pricing arena.

Grand Island's peak electric usage of 150 MW occurs in the summer. Of this peak, 50 MW is air conditioning load. Cooling results in a change of temperature of 25° F, from 100° F to 75° F. Heating requires a 75° F temperature change, from 0° F to 75° F. Since a heat pump is used for air conditioning, a valid analogy also mandates one for heating. Heating requires three times the temperature change than does air conditioning, so it will require three times the electric demand. Heat pumps are more efficient than resistance heat, with resistance heat the impact on demand could actually be greater.

Since 50 MW of demand is attributable to air conditioning, electric heat will require 150 MW, creating an additional 100 MW of demand. With saturation of electric heat, Grand Island would become a winter peaking utility with a 250 MW peak; PGS can supply only 100 MW. To serve this additional electric heating load, imagine a hypothetical 150 MW coal-fired steam generating plant. The cost of this 150 MW facility would be $250 million.

<u>Electric Heating Rates</u>: Debt service on $250 million will create an annual payment of $20 million. This hypothetical coal-fired steam plant is dedicated to serving the electric heating load, which will be at most 300,000 MWh per year. This results in a capital cost of 6.7¢/kWh. To this must be added variable generating costs such as fuel, maintenance, and labor. The resulting production cost, associated with electric heating, is 10¢/kWh.

The higher electrical demand compels corresponding expansion of distribution capabilities, another cost. Capital costs associated with distribution improvements will be about 3¢/kWh. The hypothetical electric heating rate is 13¢/kWh, producing income of $39 million.

The 13¢/kWh heating rate was based on the assumption that all customers converted to electric heat. With a homogeneous customer base, the summer and winter costs can be combined, without discriminating against customers who do not have electric heat. This simplifies the calculation of an average electric rate.

The existing revenue of $29 million and energy sales of 615,000 MWh will moderate the hypothetical average electric rate. Total income of $68 million divided by the total use of 915,000 MWh produces an average rate of 7.4¢/kWh. This is just slightly above the 7.2¢/kWh average cost of electricity in the United States. Even in the worst case, with coal-fired steam generation, Grand Island's electric rates will be nationally competitive.

Price Ceilings: The above procedure could be taken somewhat further, but the purpose is to demonstrate how electric rates will increase and produce a ceiling for the pricing of natural gas. With today's electrical demand and operating environment, a ceiling for electric rates has also been determined. The ceiling depends upon the acquisition of base load coal-fired generation.

If the decision is made to expand utilization of natural gas, production costs become dependent upon the price of natural gas. This could produce an ever escalating price spiral. The current cost of energy using natural gas is $70/MWh, which is equivalent to 7¢/kWh. With this type of expense, the continued sale of electricity for an average price of 4.7¢/kWh can not be maintained.

IRP, 2003 determines the savings realized from the purchase of 30 MW coal-fired generation to displace energy that would otherwise be produced from natural gas. Over a ten-year period, savings total $37 million.

Methodology

Escalation: The conventional method of performing capital expansion analysis is to use the present value method. An assumed discount rate is applied to a series of cash flows; the net present value of each plan is compared at the end of the study period. Factors such as capital cost and bond interest rate can be closely estimated. Other important inputs, specifically fuel prices, can not be as reliability predicted.

For Grand Island in the past 20 years, coal prices are half of what they originally were and natural gas prices have doubled. Continuing, with this historical trend, will produce erroneous results.

Rather than bias the results in favor of participation, cash flows based in current dollars are used. The cost of coal-fired generation is held constant at $10/MWh and compared with gas fired generation at today's cost of $70/MWh.

The planned completion date for Nebraska City #2 is May 2009. By then, the price of natural gas cost is expected to have continued to increase. Ignoring potential natural gas price increases, biases the study in favor of increased use of natural gas and against coal plant use.

Load Duration Curves: This study concerns meeting the energy needs of the Electric Department in the most economic manner. The annual energy needs follow a very regular trend as shown on the following figure.

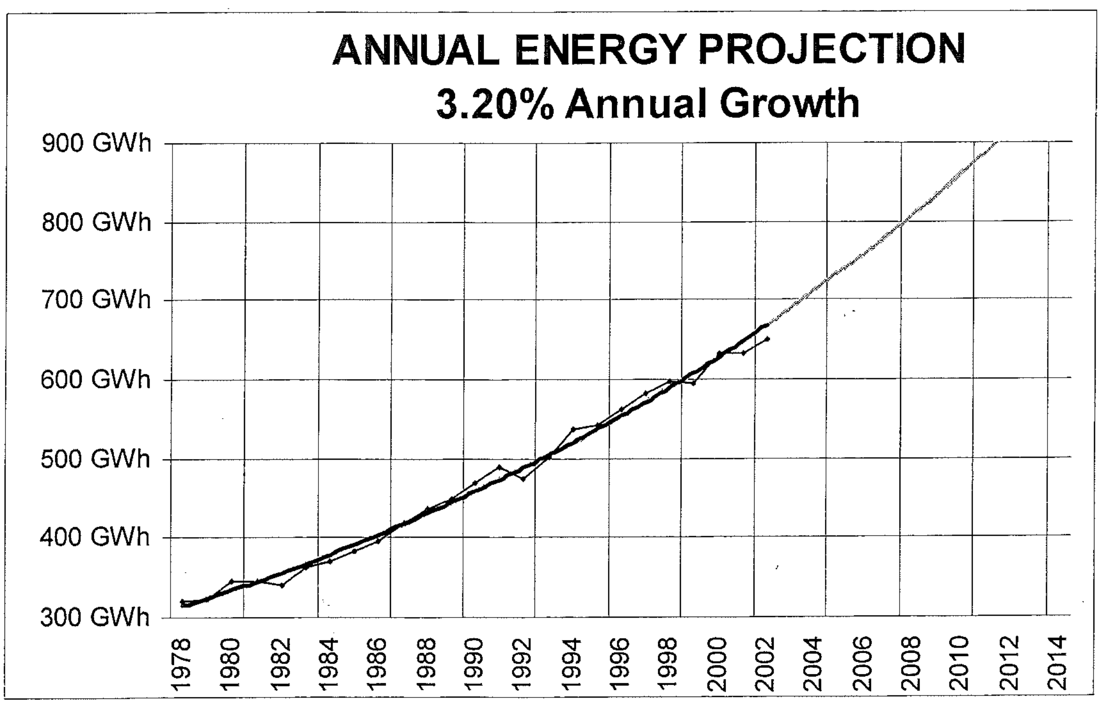


Figure 6

Monthly energy requirements are also fairly predictable, but less so than the annual requirement. Graphs of the monthly energy consumptions are provided in Appendix B.

Appendix B also contains graphs of the monthly hourly-peak demands. On a monthly basis, there are considerable fluctuations about the trend lines. As the interval is decreased from a month to the hour, predictive capability becomes more inaccurate. Forecasting the actual demand, within a reasonable range of likely demands, for more than a 48 hour during peak load periods, is only as accurate as the weather forecast. This prevents the most efficient dispatch of generating units.

Rather than attempt to derive an hour-by-hour model, an annual load duration curve is frequently employed for generation planning. The shape of the load duration curve remains nearly constant from year to year. To construct a load duration curve, the hourly demands for the period are sorted in descending order and presented graphically. The area under the graph is the energy requirement for the period. A good load duration curve to begin with is the anticipated curve for 2008 from **Integrated Resource Plan, 2001**.

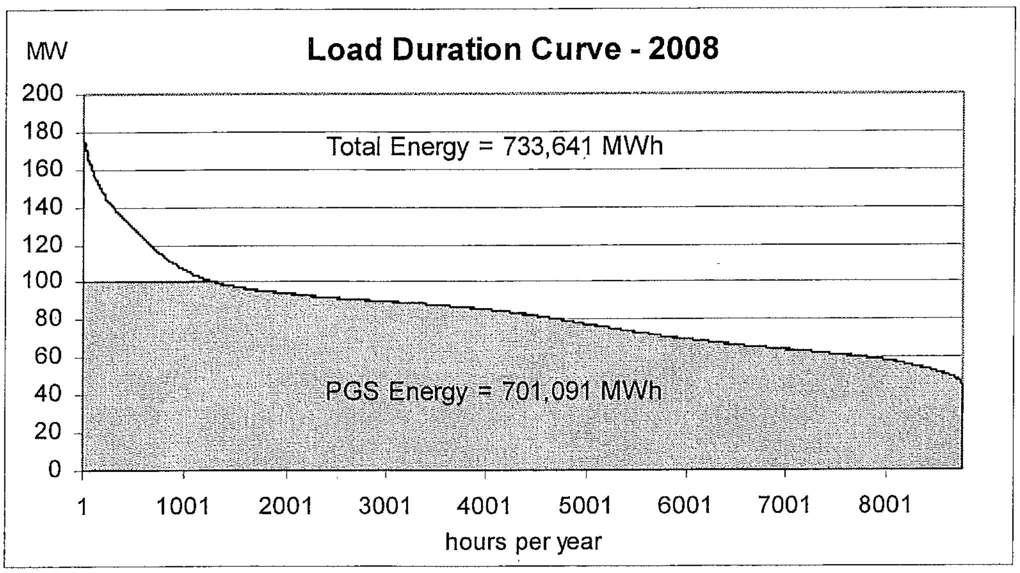


Figure 7

<u>**Interpretation of a Load Duration Curve**</u>: The preceding Figure 7 represents near optimal utilization of Grand Island's generating resources, at 2003 fuel pricing. The annual energy requirement is 733,641 MWh, this is represented by the area under the load duration curve. The short duration of peak demands has little effect on the total annual energy requirement. As long as peaking capacity is available to meet the peak demand, the magnitude uncertainty of the peak has almost no effect on the annual energy cost.

Of the annual energy requirement, 701,091 MWh is produced by coal-fired steam generation from Platte Generating Station. For 1,264 hours, the demand exceeds 100

MW, natural gas fired combustion turbines will be used to furnish the remaining 32,550 MWh of energy during the peak demand periods.

It is important to consider that one combustion turbine operates for 1,264 hours to satisfy the first 40 MW of peak demand and a second combustion turbine then runs for 289 hours to serve the remaining 40 MW of peak demand. Total combustion turbine operation is 1,553 hours to serve a peak lasting 1,264 hours. There is a NDEQ imposed environmental permit limit on the combined operating time authorized for Grand Island's new combustion turbines, so combined operating hours exceed the duration of peak demand. In this instance, to satisfy the 1,264 hours above 100 MW, the combustion turbines must have a combined operation of 1,553 hours.

<u>Annual Growth and Load Duration Curves</u>: Each year the peak demand for electricity increases by about 2.5% and the annual energy sales increase by 3.5%. This creates a family of annual load duration curves, with curves progressively larger. In constructing the curves, the hourly demands for 2002 are scaled by the appropriate demand growth. The result is a slight understatement in energy requirements. Since energy sales are increasing at a higher rate than the demand peak load, this bias understates the savings of participation in a high capital cost, low energy cost, base load resource like Nebraska City #2.

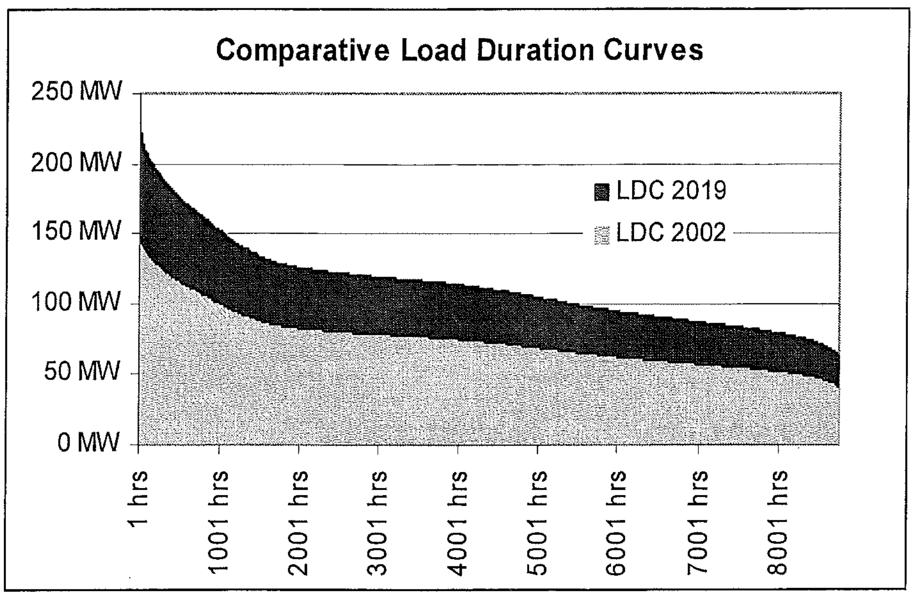


Figure 8

The study method consists of analyzing each load duration curve from 2010 through 2019 to determine the potential savings.

Study Results

Generation Type Classification: In operating an electric utility, the majority of the generation is produced by "**base load**" plants with the lowest energy production costs. "**Peaking**" plants, with high production (fuel) costs are reserved for limited use. The primary rational for this is that a coal-fired steam plant requires twice the capital investment as does a gas-fired combustion turbine. If a coal-fired steam plant is constructed, it should be used efficiently and produce most of the energy. Constructing base load generation to serve a peak lasting only 1,200 hours per year is an inefficient use of capital.

In 2008, PGS produces 95% of Grand Island's energy needs. At full 100 MW capacity it supplies only 55% of the annual demand. The remaining 45% of the capacity need comes from combustion turbines, which provide only 5% of the energy. Neither type of generation intrudes upon the intended specialty of the other; this is by design. Load duration curves combined with the 100 MW rating of PGS were used to select the capacity of the new combustion turbines.

In the years beyond 2008, a gap will develop between the 100 MW base load capability of PGS and the 80 MW peaking capacity of the combustion turbines. This gap is initially filled by energy from an ill-defined "**intermediate**" unit. The Burdick Station natural gas-fired steam generating units were originally constructed for base load generation and are not designed for peaking service; Grand Island now considers them intermediate units.

Intermediate units lack either "high capital – low operating" or "low capital – high operating" cost characteristic. Being paid for, Burdick Station steam units have a very low capital cost. As was shown in **IRP, 2001**, operating the Burdick Station steam generation displaces coal fired generation with natural gas fired generation. This displacement makes gas fired steam generation production cost uneconomic.

It is imperative to look at acquisition of base load, low energy cost, coal-fired generation to avoid the high production costs. A 30 MW coal fired addition will initially behave as "**intermediate**" generation, not fully utilized every month of the year. By 2014, the entire 30 MW will be needed each month of the year as "**base load**" generation, supplementing PGS.

Base load vs. peaking costs: Grand Island has sufficient generating capacity to serve its load through 2019, the end of the study period. Much of this capacity is a mixture of peaking and older intermediate units at Burdick Station. Utilizing natural gas, the nominal production cost from the Burdick Station units is $70/MWh. Since the units are in place, no new capital cost is associated with Burdick Station; that is, $70/MWh is the only cost associated with the natural gas fired generation.

Participation in Nebraska City #2 will require a capital investment of approximately $1,500,000 per MW amortized over 40 years at a 5% interest rate. There is also an annual transmission expense of $48,000 per MW, required to move power from Nebraska City #2 to Grand Island; with Burdick Station, local transmission is already owned. Energy cost from Nebraska City #2 is projected to be $10/MWh.

To determine the feasibility of Nebraska City #2 participation an economic analysis is used to determine if it will be used for a sufficient number of hours during each year to justify the capital cost. Figure 9 shows that if Nebraska City #2 energy is needed for more than 2,300 hours per year, participation is prudent. After 2,300 hours use, the total cost of Nebraska City #2 energy drops below the $70/MWh energy production cost of natural gas produced energy from Burdick Station.

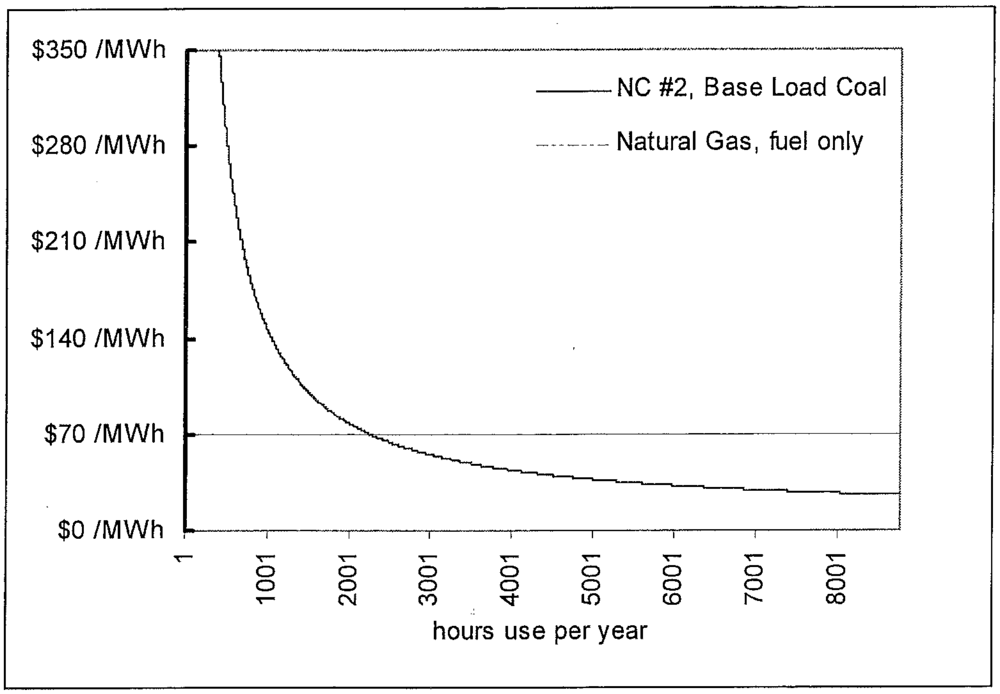


Figure 9

It is relatively easy to determine how many hours a year that a single MW will be used. Determining beneficial use of a 30 MW block of power is more difficult. The second part of this study models the monthly generation needs, hour by hour, to determine the annual savings (or cost) associated with participation. It turns out that the savings, resulting from a 30 MW block of low production cost energy, over the 10-year study period are approximately $37 million.

__Nebraska City #2 vs. New Combustion Turbines__: The combustion turbines (CTs), which were the focus of **IRP, 2001**, became operational in 2003. The economics of this addition are driven by the fact that combustion turbines have load following capabilities superior to the Burdick Station steam units. Allowing optimization of the gas – coal fuel mix for energy production, resulting in more efficient, i.e. minimal, use of expensive natural gas.

In 2001 there were no opportunities to participate in base load coal-fired generation. With the Nebraska City #2 offer, the economic evaluation compares the cost vs. use characteristics of the two unit types. Nebraska City #2 costs, again, will be those just described. The combustion turbine cost is $700,000/MW amortized over 15 years at 5% interest. There is no transmission cost associated with the CTs but fuel cost is $70/MWh. The new combustion turbine cost curve is added to the previous graph and is shown on Figure 10.

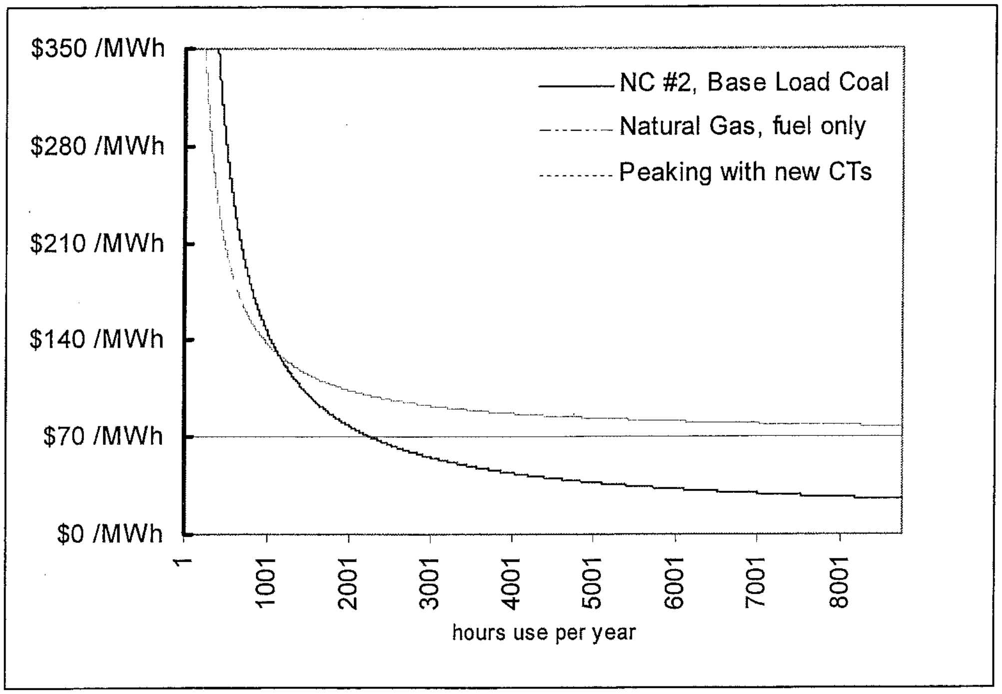


Figure 10

The Nebraska City #2 cost curve intersects with the new CT cost curve at 1,200 hours. It is more cost efficient to install combustion turbine peaking units, if the need for the power does not exceed 1,200 hours per year. As demonstrated by the load duration curve for 2014, Figure 11, 100 MW from PGS and 30 MW from Nebraska City #2 provide energy for the base load, 80 MW of combustion turbine peaking generation is needed for 1,200 hours per year.

With Nebraska City #2 participation, the optimum mix of generation and load has moved from 2008 to 2014. The load duration curve for 2014 depicts 130 MW of base load coal-fired generation, supplemented by 80 MW of combustion turbines for 1,200 hours per year. With increasing demand and added base load generation, the combustion turbines allow continued optimum mix of base and peak load generation.

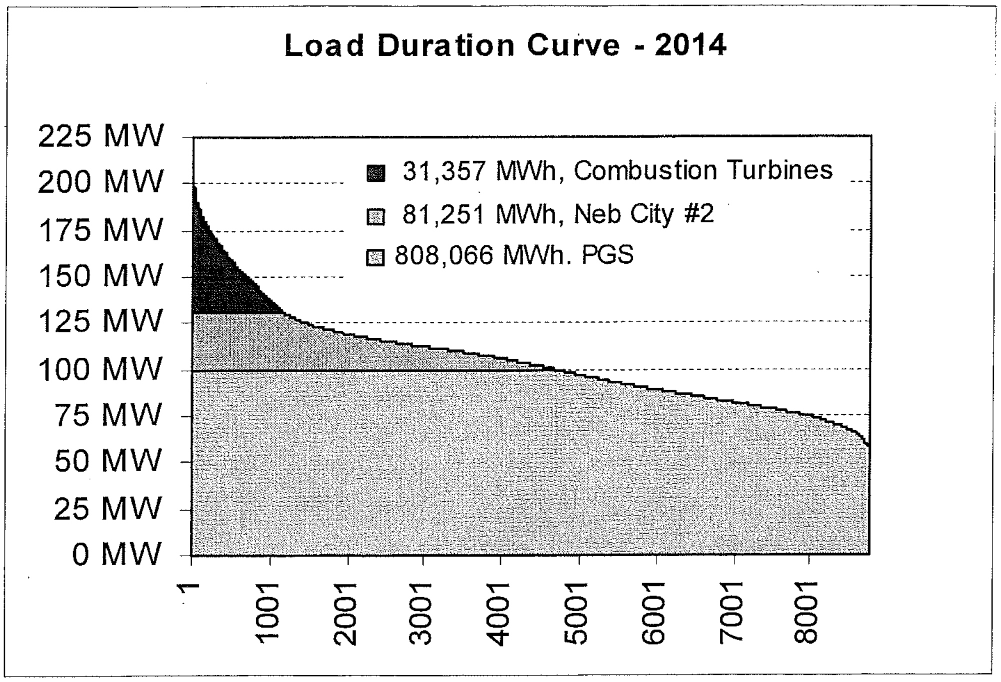


Figure 11

<u>Potential Savings</u>: The projected energy utilization from Nebraska City #2 for 2014 is 81,251 MWh. With 30 MW of participation, the average use is 2,708 hours which exceeds the 2,300 hour break-even usage. With annually increasing load growth, utilization of Nebraska City #2 will continue to increase.

With increased utilization comes increased savings. Over the 10-year study period, projected savings total $37 million. The second part of **IRP, 2003** provides a detailed analysis of how the savings are calculated.

Beyond 2014, the increasing demand will cause a gap to develop between the 130 MW capacity of coal-fired generation and the 80 MW peaking capability of the combustion turbines. The Burdick Station steam units can be used to fill this gap, but eventually it will become necessary to acquire additional base load capacity.

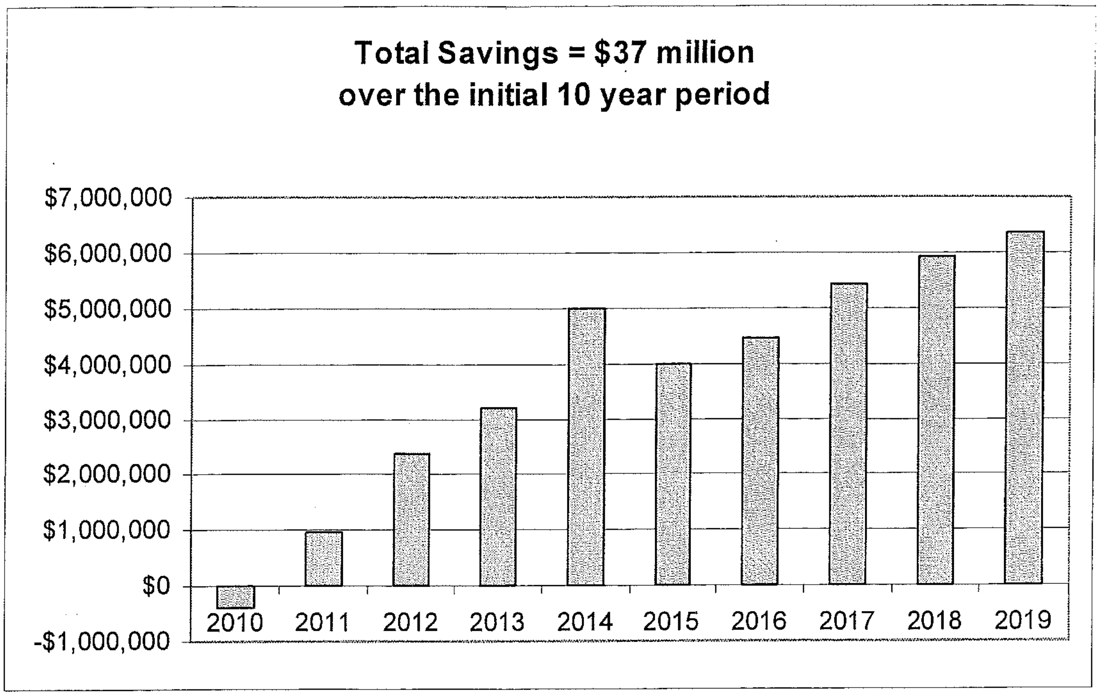


Figure 12

Coal Fired Options: Since 2001 utilities are again considering coal fired generation. Three such plants are being considered in Nebraska. NPPD is considering a coal fired plant, possibly located at a former Army Ammunition Plant near Grand Island. If constructed Grand Island has requested a 40 MW level of participation. A group of eight utilities are considering the MEAN/Hastings addition to the Whelan Energy Center. If constructed, Grand Island is considering a 15 MW level of participation. These plants remain in the discussion stage, neither has Power Review Board approval.

OPPD intends to construct an addition at its Nebraska City site. Nebraska City #2 has Power Review Board approval for up to 600 MW; 300 MW for use by OPPD and up to 300 MW for utilities wishing to participate in the plant. Grand Island has requested a 30 MW level of participation. This **Integrated Resource Plan, 2003** examines the feasibility of the requested 30 MW level of participation.

As of this writing, comparison among discussed coal plants is largely speculation. There are no guarantees that other coal fired plants will be constructed in Nebraska. As it turns out, the timing and participation level of Nebraska City #2 is a good match to Grand Island's current needs.

Participation will not preclude participation in other coal fired plants. Even with Nebraska City #2 participation, by 2015 Burdick Station steam generation will be operated as "**intermediate**" generation, to meet projected demand growth. By 2018 there will be strong economic need for additional base load generation. By 2022, all three of coal-fired options will be needed to stabilize production costs.

Public Input and City Council Resolution: Appendix C provides copies of recent memos and Resolutions regarding Nebraska City #2. Three potential generating plants are in various stages of consideration. It is difficult to discuss a single activity, to the exclusion of other options, this is apparent in the memos. There has been much public involvement.

Grand Island City Council Resolution 2003-52, on February 18, 2003, authorized a Memorandum of Understanding agreement between Grand Island and Omaha Public Power District, which enabled development of the Power Participation Agreement.

Most recently, the Electric Department conducted a presentation on the feasibility of Nebraska City #2 participation during the City Council Study Session of October 7, 2003. One week later, at the regularly scheduled meeting of October 14, 2003, the Grand Island City Council passed Resolution 2003-279. This Resolution approves obtaining 30 MW of participation in OPPD's Nebraska City #2 power plant.

IRP, 2003; Part #2
Evaluation Details

Rationale for Two Parts

Intent: Part #1 of **IRP, 2003** summarized considerations involved with making the decision for participation in Nebraska City #2. Based on usage hours of Nebraska City #2 energy, participation was marginally justified by 2014; but after 2014 savings increase rapidly and continue through the life of the unit. The transition from the simple explanation to a more detailed model is completed in **IRP, 2003** Part #2, so the report was split into two parts. Part #2 is independent of Part #1 and can be read separately; for this reason, there is some degree of repetition.

A graph showing the annual savings, which total $37 million over the first 10-years of Nebraska City #2 participation, is presented in Figure 13, page 22. Part #2 of **IRP, 2003** calculates the estimated savings.

Analysis Method: Grand Island's load duration curve for 2008 is shown as Figure 1. This is an optimal condition for dispatching the existing generation. The "**base load**" Platte Generating Station (PGS) fills the bottom of Grand Island's 2008 load duration curve and furnishes 95% of Grand Island's energy requirement. During the summer peak demand periods, the remaining 5% of the energy is produced by starting and stopping the "**peaking**" combustion turbines on a daily basis.

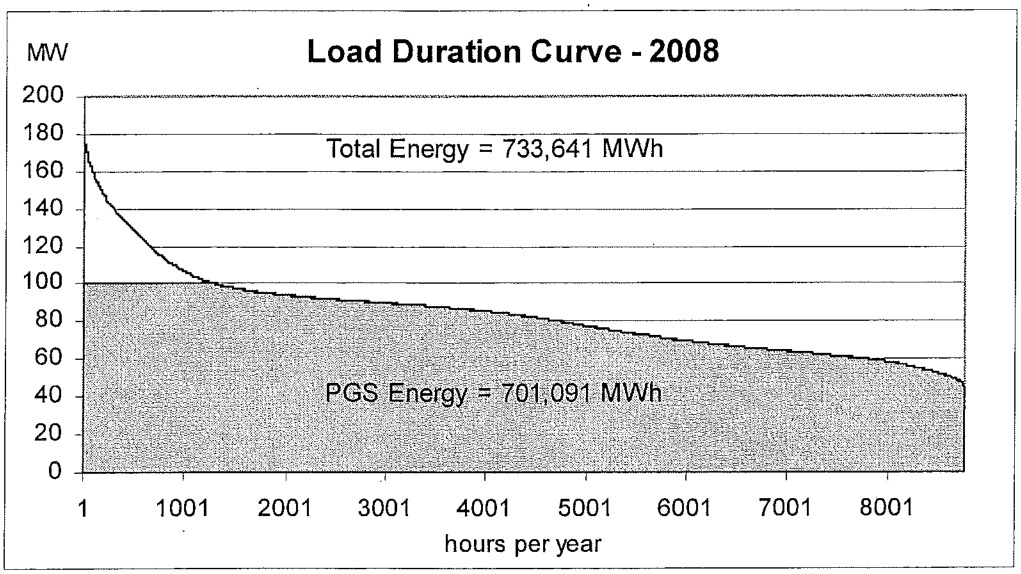


Figure 1

Beyond the 2008 peak demand of 180 MW, a gap will occur between the 100 MW maximum capacity of PGS and the 80 MW peaking capability of the combustion turbines. This gap will annually increase as the peak demand grows. The generation used to fill this gap is classified as "**intermediate**" generation.

With the present generating resources, Burdick Station steam generation will be operated as "**intermediate**" generation. Burdick Station steam generation was installed, as base load generation, from 1956 through 1972, when natural gas was the inexpensive fuel. Although they will fill the "**intermediate**" gap, Burdick Station steam generation remain base load units; they are not designed for daily starting and stopping.

During the summer peak load period, the hourly night-time demand falls below 100 MW. Burdick Station steam units must run throughout the night; this natural gas fired generation will displace energy which could potentially be produced by the low cost Platte Generating Station. Since the load duration curve arranges hourly demand by magnitude rather than temporally, the displacement is difficult to display and adds a level of complexity to the analysis.

Annual load duration curves lack sufficient granularity to give an accurate approximation of operating restrictions and cost. The annual load duration curves must be divided into monthly curves and then analyzed. The monthly load duration curves can then be recombined to form an annual load duration curve that accurately portrays natural gas generation intruding on generation that is most economically produced by base load coal-fired generation. Part #2 addresses this procedure.

IRP Rules: The Electric Department purchases an annual 9,168 kW and 33,428 MWh from the Western Area Power Administration (WAPA). These comparatively small amounts are not explicitly shown in either Part #1 or Part #2. The 9 MW capacity is included in operating reserves. The 33 GWh has costs similar to PGS, with which it is tacitly included.

WAPA is an agency of the Federal Government, marketing energy from the Missouri River dams. Purchasing power and energy from WAPA subjects Grand Island certain reporting requirements including Integrated Resource Planning.

WAPA has prepared a checklist, simplifying compliance with IRP Rules; this checklist is provided in Appendix D. Some of the checklist items did not fit well in Part #1 of **IRP, 2003** and were deferred to Part #2.

Variables

Project: Nebraska City #2 is a 600 MW, coal-fired, steam generating plant. It is being constructed by Omaha Public Power District (OPPD); 300 MW is reserved for use by OPPD and the remaining 300 MW is offered to other utilities on 40 year to "life-of-plant" participation basis. The unit will be constructed on an existing site, adjacent to Nebraska City #1. The site has dual rail access and the boiler will burn Powder River Basin coal from Wyoming. Although it is situated on the Missouri River, cooling towers will be used for condenser cooling; there should be minimal impact on the river temperatures.

The plant has the approval of the Nebraska Power Review Board. Grand Island has requested to participate at the 30 MW level.

Period of Study: The planned operational date for Nebraska City #2 is May 2009. With projects of this magnitude, some schedule slippage can occur. Rather than deal with a partial year, 2010, the first full year of operation, is used in this comparison.

The study period ends in 2019. Grand Island requires no additional capacity until about 2019. Ending the **IRP, 2003** at 2019 provides an evaluation based solely upon the cost of energy. This is a considerable simplification. By 2019, the output from Grand Island's share of Nebraska City #2 is fully utilized and the cost saving trends for future years established.

Participating in Nebraska City #2 will add 30 MW of capacity and satisfy Grand Island's capacity obligation through 2024. Again this participation purchase is economically evaluated based solely on savings in energy cost. The capacity, valued at $2.6 million annually, is not included in the evaluation.

Variable Production Costs: This evaluation is based on the cost of natural gas generation to the cost of coal generation. Production costs are substituted for unit heat rates and raw fuel costs. Using current fuel prices, natural gas generation is set at a variable cost of $70/MWh and the cost of coal generation is set at to be $10/MWh. These are today's costs and are assumed to remain constant, throughout the ten-year study period.

Maintenance costs are considered identical, among the generating units, so they can be excluded and simplify the analysis. Since maintenance cost for combustion turbines will probably exceed those for coal fired steam generation, the error is in favor of natural gas generation.

Capital Costs: No new capital investment is required for existing generation at either Platte Generating Station or Burdick Station. Participation in Nebraska City #2 will require a capital investment of approximately $1,500,000 per MW or $45 million for the

30 MW participation. Amortized over 40 years, the expected life of plant, at a 5% interest rate, this amounts to $2,622,515 per year.

Financing is the responsibility of OPPD. Amortized capital payments will be included as a fixed component of monthly operating costs, billed by OPPD.

CT Restrictions: GT-2 and GT-3 are Permitted, by the Nebraska Department of Environmental Quality, for operation totaling 5,000 hours per 12 month period, for both turbines combined. Operation on oil is limited to 240 hours per 12 month period for both turbines combined. To reach full output both turbines combined need to operate; for generation less than 40 MW, only one turbine is used. Assuming linear loading, the usage of the combustion turbine pair is limited to about 3,300 hours or 300 hours per month.

If gas peaking generation is required beyond 300 hours per month, it is allocated to the Burdick Station steam units. If needed, these steam units will then be assumed to be on-line for an entire month. Burdick Station steam generation will displace coal-fired generation from PGS during the off-peak hours.

Although not directly related to the, study imposed, 300 hour per month restriction, the findings of Part #1 place the limit in perspective. It was demonstrated that natural gas should not be fired more than 2,300 hours per year, an average of 200 hours per month. And that a combustion turbine addition should not be installed if the planned operation is more than 1,200 hours per year, an average of 100 hours per month. In each of these cases it is more economical to acquire new coal-fired capacity.

In the model each month is presented as a series of predetermined hourly loads. From the monthly load graphs of Appendix B, it is shown that peak monthly demands vary considerably from the expected demand used in the model. Generation must be committed for the highest expected demand plus operating reserves. The model commits generation only to satisfy the expected demand, as shown by the trend line. Scaling hourly demands to correspond with potential peak demands would result in a large overstatement of energy requirements, strongly biasing the Study in favor of adding low cost energy resources.

Due to the extended run times, commitment of the Burdick Station steam generation is planned several days in advance. In the absence of accurate 10 to 14 day hourly weather forecasts, there will be many times when the selection of generation type cannot be optimized. For example, combustion turbines will be operated for consecutive days with unexpectedly unseasonable temperatures, wasting allotted hours. At other times, loads will not materialize and gas fired steam generation will have been placed on-line, rather than utilizing the combustion turbines. Both types of weather forecast errors contribute to the restriction of 300 hours per month of peaking capacity utilization.

Outages: No adjustment is made for plant outages, scheduled or unscheduled; the availability of generating units is considered to be 100%. Platte Generating Station normally has one-week spring and fall scheduled maintenance outages. At five year intervals, PGS has major maintenance outages, lasting approximately six weeks; three years after the five year outage there is also an extended outage to perform a semi-major inspection.

Since base load generation is removed from service for the outage periods, it is desirable to find replacement base load energy. Ignoring outages biases the study results in favor of operating gas fired steam generation, rather than participating in Nebraska City #2.

Energy Growth: Energy growth rates are slightly higher than the monthly demand growth rates. Load duration curves are created by escalating the hourly demands. The energy requirements are therefore understated. This creates a slight bias against participating in Nebraska City #2.

Transmission: To move power from Nebraska City #2 to Grand Island, a distance of 150 miles, the transmission facilities of both Omaha Public Power District and Nebraska Public Power District (NPPD) must be used. Grand Island will pay each entity's transmission tariff. A total rate of $4/kW-month is used in the cost model.

As modeled, the annual fixed transmission charge is $1,440,000, while the annual fixed generation capacity charge is $2,622,600. The 150 mile transmission path could fit inside the service area of either utility. If transmission were confined to a single utility's service area, this would result in paying transmission charges based on a single tariff. The Federal Energy Regulatory Commission is attempting to eliminate "pancaked rates." Whether transmission costs will decrease by 2010 is subject to speculation.

Grand Island's load had increased since the 115 kV interconnection was established with NPPD in 1970. This necessitated the replacement of large transformers in the NPPD substation. The replacement was completed in December 2001. Grand Island financed the project and, in turn, is receiving transmission credits from NPPD through December 31, 2014. The NPPD transmission credit is recognized by this model.

Fuel Alternatives and Environmental Considerations

Purpose of Section: Natural gas and coal are the only fuels modeled. For the sake of completeness, the potential fuel alternatives and environmental concerns need to be considered. Qualitative considerations are appropriate, since environmental constraints are generally legislated.

Coal: Availability of coal and transportation are readily confirmable. The price of coal and transportation is historically fairly stable. Fuel cost from coal fired generation has been assumed constant for this **IRP, 2003**. If that assumption is invalid, a new round of price escalation and inflation will begin. If that is the case, the best option is to make the capital investment in a new plant before capital costs increase.

Being the most widely used electric generation fuel, coal is subject to continued criticism for environmental degradation. Emissions of particulates, sulfur oxides, and nitrous oxides are now tightly controlled. Other restrictions will be imposed at a financial cost; this cost will affect all utilities fairly equally and should not have much impact on Grand Island's comparative ranking of electric rates.

Nebraska City #2 will use coal from surface mines in the Powder River Basin. Upon completion of mining, the sites are restored in an environmentally acceptable manner.

Natural Gas: The primary concern with natural gas is availability. With the current generation mix, the Electric Department will soon become dependent upon natural gas during the winter heating system. Since this is the peak time for residential and commercial gas usage, electric generation using natural gas may again be curtailed. This possibility, alone, is strong justification for acquiring new coal-fired generating capacity.

It is difficult to quantify, potential curtailment of natural gas. This quantification is unnecessary. **IRP, 2003** provides a solely cost based evaluation for additional coal-fired generation.

Oil: Oil can be stored and substituted, to a limited extent, for natural gas. The only advantage that oil has over natural gas is ease of storage. Much of the oil historically used in the United States is imported, making it a less dependable fuel than natural gas. Oil is more costly than is natural gas. Air quality permitting limits the amount of oil that can be fired, without the installation of emissions monitoring equipment. Oil is stored for emergency use, but it is not a viable substitute for natural gas.

Although oil can be fired at Burdick Station, it is an expensive substitute for natural gas.

Liquefied Natural Gas (LNG): Propane is the most well known LNG. It has greater heat content than natural gas; mixed with air it can be used as a fuel for generation.

The price of LNG should be comparable to that of natural gas. However, Grand Island's generation is not currently permitted to fire propane and delivery and storage of the large quantities required for power generation presents a problem. Primary production of LNG is overseas, making the product susceptible to embargos.

Burdick Station is not designed to fire LNG, so its use is not modeled.

Nuclear: Further development and continued use of nuclear power is a political issue. The technology is viable but regulations have destroyed its potential. After thirty years, the Federal Government has not yet provided for storage of the high level radioactive wastes. These wastes are still in temporary storage at plant sites; long term storage prospects remain uncertain. Political and public acceptance remain uncertain.

Hydro-Electric Power: Hydro-electric energy is not under consideration. Even if acceptable sites remain, building dams is extremely capital intensive. Electric revenues are likely to be inadequate to support such a project, without a cross subsidy from primary beneficiaries such as flood control, navigation, and irrigation.

Dams are presenting unintended environmental conflicts. Creating ecological hardships for some species and niches for others, solutions and compromises are difficult to derive.

Wind: At the present time, fossil generation is more cost effective than wind power, which remains financially subsidized. Wind is variable and generation from wind can not be relied upon as dependable capacity. Wind is not a substitute for conventional generation, which must be running to compensate for variations in wind speed. Installation of wind generation does not reduce capital expenditures. It does reduce fuel consumption and associated emissions, to some extent.

There is a limit to the amount of wind generation that can be installed. Because production varies with wind speed, wind generation cannot be dispatched to meet load. Installed in a utility's service area, undispatched wind generation behaves like a reduction in load. Grand Island is in the flyway for migratory waterfowl, including three endangered bird species, which prohibits local installation of wind turbines.

Wind turbines must be sized so as not to interfere with the normal operation of transmission and generation. When installed outside a service area, control and transmission issues become problematic.

Grand Island is a minor participant in the NPPD wind turbine project at Springview. Should other opportunities for wind energy participation develop, they will be considered.

Hydrogen: Combustion of coal, oil, LNG, and natural gas all produce carbon dioxide in varying amounts. Carbon dioxide is considered a greenhouse gas and may become subject to regulation. Hydrogen is being promoted as a substitute for carbon containing fuels, but this fuel source has not yet matured.

Environmental Consequences of Electric Heat: Consumers are free to make economic choices. Increasingly, the source of energy for space heating is becoming an economic consideration. As explained in Part #1, the Electric Department has little influence over the direction the scales tip.

Ground coupled heat pumps are efficient and popular. The sub-soil in and around Grand Island is largely sand; leaks of the heat pump working fluid could cause contamination of ground water. With three times the heat being removed from the ground, as is being replaced, concentrated long term use of heat pumps can be expected to change the sub-soil temperatures.

Load Duration Curves

Peak Demands: In load duration curves, demands are displayed, in decreasing magnitude, from left to right. This is a simplification that approximates reality. Demands do not occur in consecutively decreasing order, hour by hour, for the entire year. But as long as the resource mix is restricted to base-load and peaking generation of sufficient capacity, an acceptable approximation of operating costs can be derived by using the annual load duration curve.

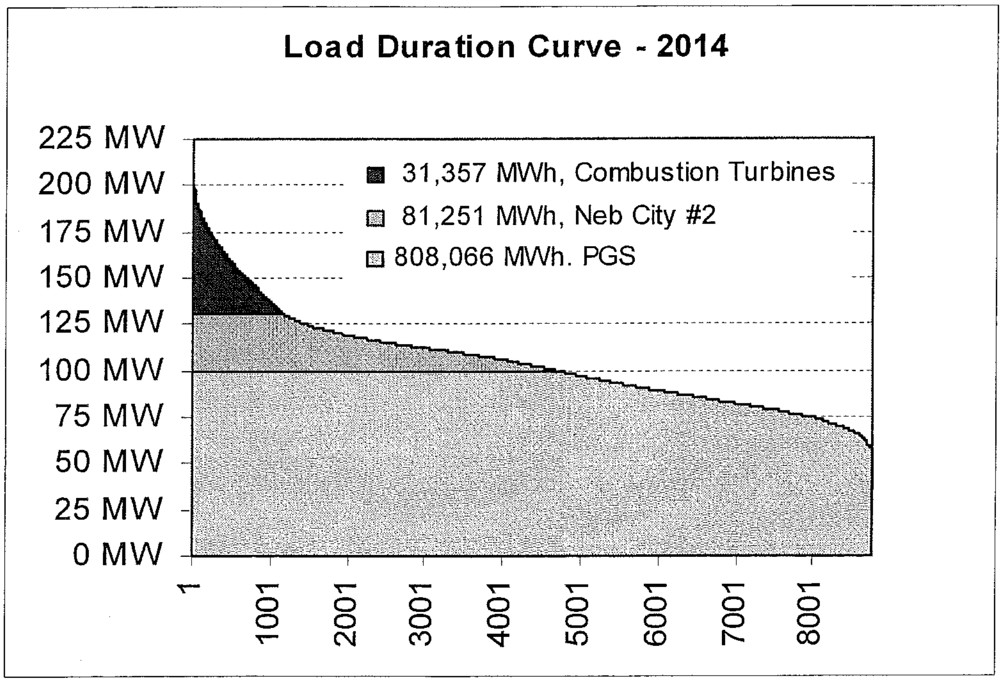


Figure 2

Peaking capacity follows load well; it can be started and stopped, as needed, throughout the year. Base load is the lowest cost source of energy; it is run continuously throughout the year and requires only minimal load following capabilities. Intermediate capacity, in the form of Burdick steam generation, can not be readily started and stopped; it does not match load well for Grand Island's annual load duration curve.

A compilation of the monthly demand and energy projections is included in Appendix B. With current generation resources, Burdick Station steam generation is needed to satisfy the summer demands as early as 2010. The addition of Nebraska City #2 coincides closely with the needs of the Electric Department and reduces the need to operate gas-fired steam generation.

Load Factor: As a measure of efficient use of a capital investment the average production from a plant is compared to the peak production capability; this is termed capacity factor. Grand Island's load duration curve shows that base load generation can operate with a capacity factor of about 80%; in reality, scheduled maintenance outages reduce this to about 65%.

Load factor is similar to capacity factor; except average demand is divided by peak demand. The projected load factor for 2014 is 54%. In the absence of low capital cost peaking units, base load generation could only achieve a maximum 54% capacity factor. This is an inefficient use of capital. The annual, actual and projected, load factor is included in Appendix B.

Load factor is a measure of the flatness of the load duration curve. A unity load factor creates a flat curve. In 2002, the monthly load factor varied from 53% in May to 78% in January. January is consistently cold, resulting in a fairly flat curve. Air conditioners are started for a few hot days in May, while the remainder of the month is mild. July is constantly hot, resulting in a 67% load factor.

Load factor is not used directly in the calculations, but the concept helps explain the differences among the varying operating conditions. A utility with a low annual load factor benefits from peaking type generation. A high annual load factor permits efficient use of base load generation.

Unit Loadings: In the model of Part #2, Platte Generating Station is operated for each hour of the year. Furnishing up to 100 MW, PGS energy fills the base of the load duration curve.

The combustion turbines can supply up to 80 MW for peaking duty, this is the upper left corner of the load duration curve. If it appears the combustion turbines will be required for more than 300 hours per month, Burdick Station steam generation is modeled on-line.

If placed on line, Burdick Station steam generation sits above all coal-fired generation and below any combustion turbine energy. If placed on line, Burdick Station steam units are operated, for the entire month, at a minimum output of 15 MW. The minimum output has the potential of displacing coal fired energy and represents a significant production cost, which is reduced by adding base load capacity.

Being base load coal-fired generation, Nebraska City #2 is utilized as much of the month as possible. It is placed just above PGS on the monthly load duration curves. In reality, projected energy costs from Nebraska City #2 are lower than those from PGS and Nebraska City #2 will fill the bottom section of the load duration curve. This configuration would make evaluating participation more difficult, but participation would be even more cost effective.

In the absence of Nebraska City #2 participation, the energy block attributed to Nebraska City #2 represents natural gas energy. The $70/MWh verses $10/MWh cost difference is always a factor in evaluating participation.

Unit Commitment

<u>**Monthly Load Duration Curves**</u>: **IRP, 2001** examined two types of generation, each using natural gas as the fuel; older steam units originally designed and operated as base load generation and combustion turbines designed to operate as peaking units. For this comparison, annual load duration curves were satisfactory. **Integrated Resource Plan, 2003** compares steam turbines, one burning coal the other firing natural gas. These turbines have widely differing capital costs; Burdick Station steam generation is debt free, while Grand Island's share of Nebraska City #2 will be about $45,000,000.

In some months, generation from Burdick Station steam units is required to meet the demand, in other months it is not needed. Operating hour limitations imposed by environmental permitting will occasionally force operation of Burdick steam generation instead of the, preferred, combustion turbines. Annual load duration curves lack the granularity required to obtain valid results, so monthly load duration curves were constructed.

(1) In all cases, i.e. each month, Platte Generating Station is the base load unit and achieved the maximum 100 MW output during the month.

(2) A second layer, of up to 30 MW, is then placed on top of the PGS base layer and designated "Neb City #2." The "Neb City #2" layer is the base amount of coal-fired energy supplied by Nebraska City #2, should that option be selected. Otherwise, the Neb City #2 energy block will be gas-fired generation, either from Burdick Station steam units or combustion turbines.

(3) If the monthly demand exceeds 130 MW, a third layer, along the left axis, is required. Depending on the number of hours this generation is needed, the energy could come from gas fired combustion turbines or steam units.

(4) If Burdick Steam units are operated, they are on-line for the entire month. If the power is unneeded, there is 15 MW band sitting on top of and displacing energy that would otherwise be produced by Platte Generating Station. It is this band of gas fired energy that complicates and seriously impacts the analysis.

Five operating conditions are recognized.

Condition #1: With a peak monthly demand of 130 MW or less, the entire load can be served with a combination of Platte Generating Station and Nebraska City #2. In the absence of Nebraska City #2, combustion turbines can be used, for fewer than 300 hours per month, to furnish peaking power. Condition #1 is most likely in a high load factor month.

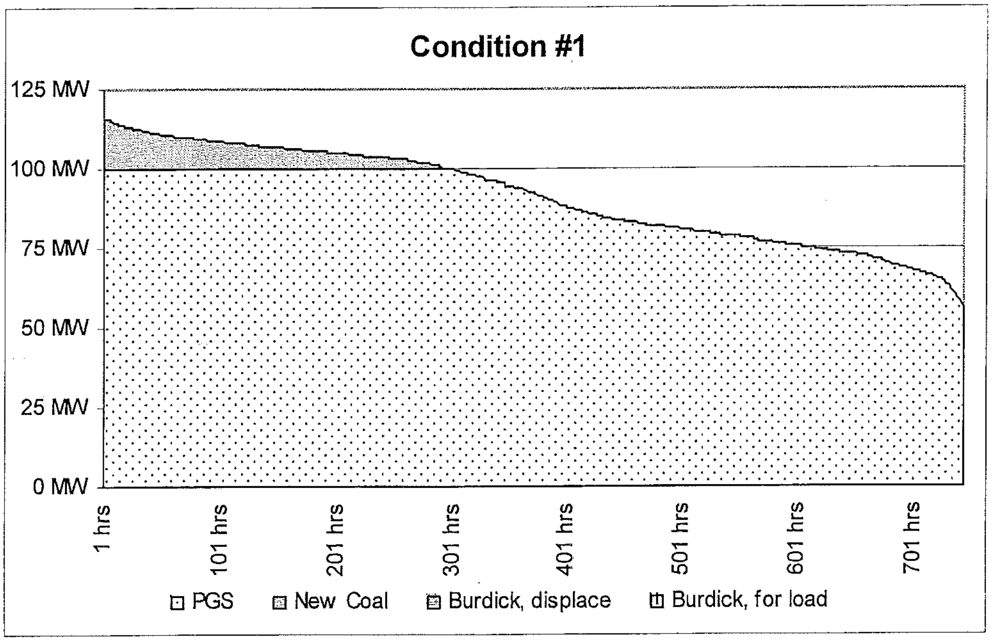


Figure 3

Condition #2: The peak monthly demand exceeds 130 MW, but being of fairly short duration, it can be served with a combination of PGS and the combustion turbines. The short duration peak places Condition #2 in low load factor months.

Participation in Nebraska City #2 eliminates some of the need to run the combustion turbines. In the example shown, the load factor is 60% and the peak load duration is approximately 100 hours.

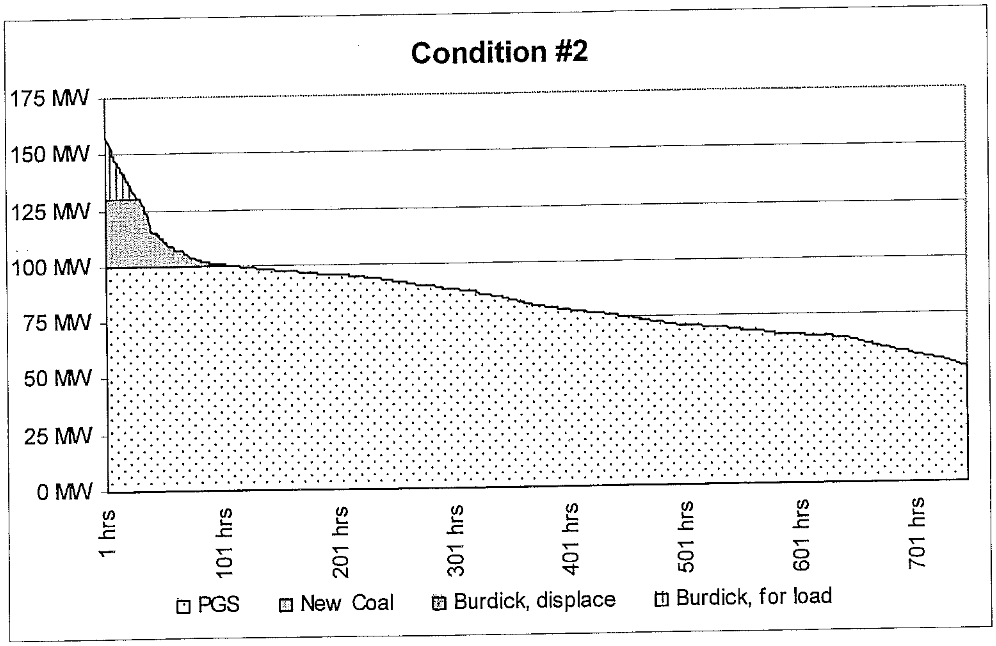


Figure 4

Condition #3: The peak demand is less than 130 MW, but the monthly load duration curve is relatively flat. A flat load duration curve represents a high load factor month.

Since the combustion turbines would need to operate for more than 300 hours during these months, Burdick Station steam generation is used to supplement Platte Generating Station. The result of Burdick Station steam generation, firing natural gas, operating at minimum load for the entire month is a large block of coal-fired energy that would otherwise be produced by coal fired energy.

Since the peak demand is less than 130 MW, participation in Nebraska City #2 will permit the total energy needs to be produced by coal-fired generation.

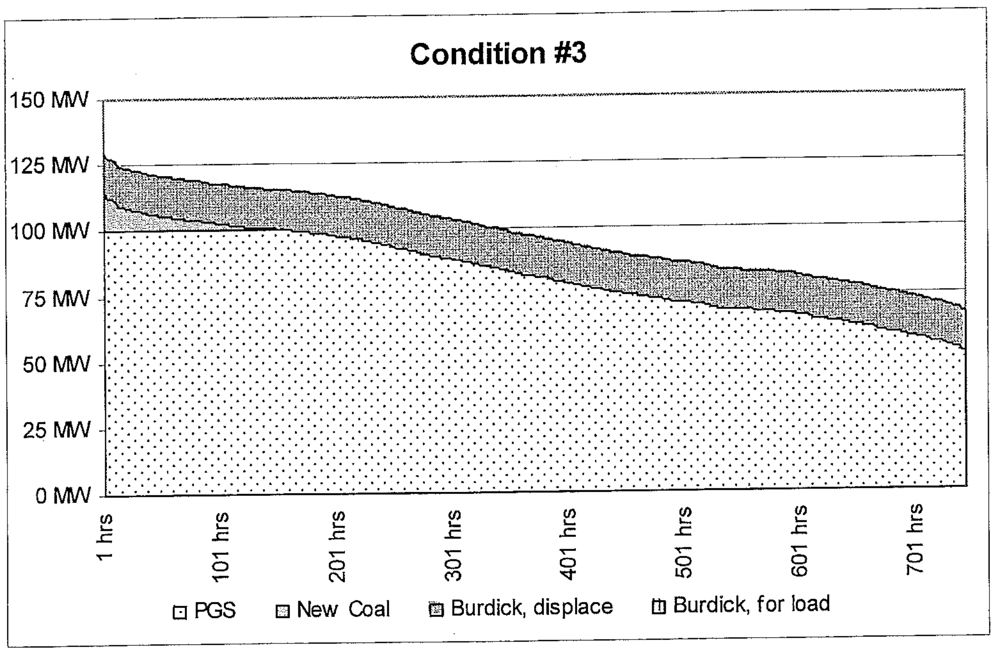


Figure 5

Condition #4: The monthly demand is sufficiently high to require both the combustion turbines and Burdick Station steam generation or Nebraska City #2. Condition #4 is first experienced in low load factor months. Since it is dependent upon demand, each month will eventually reach Condition #4.

If Grand Island participates in Nebraska City #2, the combustion turbines will operate less than 300 hours per month. With participation, savings result from both the direct Nebraska City #2 purchase and avoiding operating Burdick Station steam generation at minimum for most of the month.

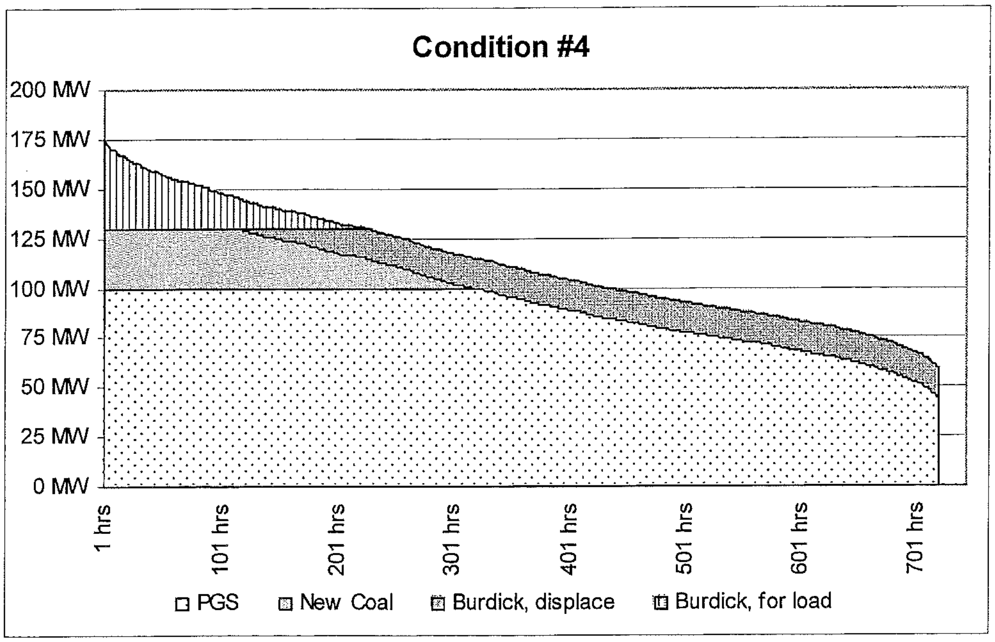


Figure 6

Condition #5: The monthly demand is sufficiently high to require both the combustion turbines and Burdick Station steam generation or Nebraska City #2. Even with participation in Nebraska City #2, natural gas generation will exceed 300 hours per month. Burdick Station steam generation will operate all month. Since participation makes no difference on the operation of Burdick Steam generation, there will be no savings of displaced energy. The only savings realized will be the block of energy between 100 MW and 130 MW, extending to approximately 300 hours.

Eventually all months will reach Condition #5. Before this happens, it will be necessary to acquire more base load generation.

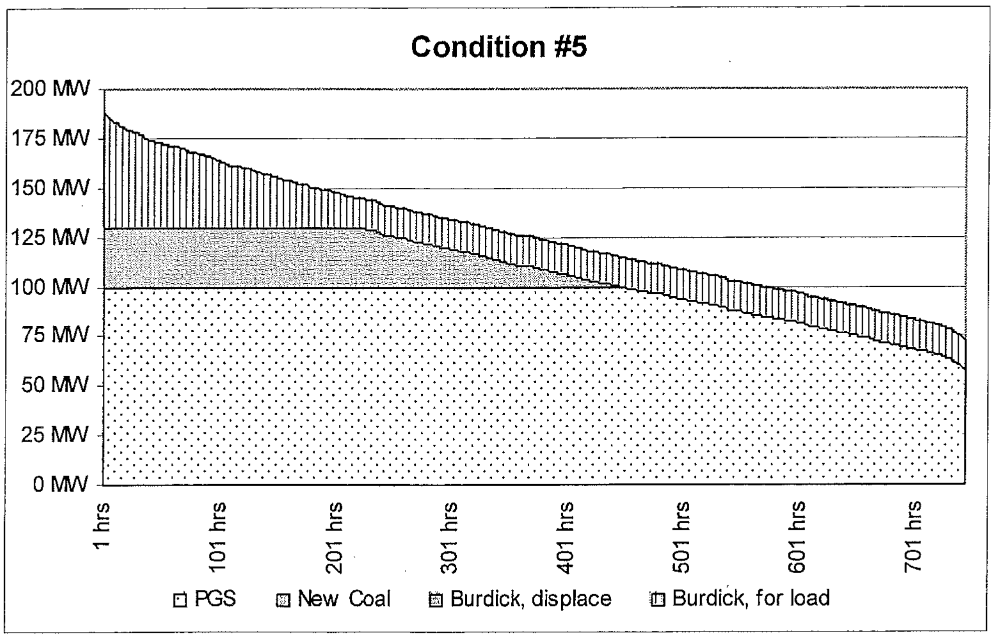


Figure 7

Monthly Unit Commitment Conditions: The 2002 monthly demands are scaled to reflect the monthly peaks for each year from 2010 through 2019. Generation is committed as described in the Unit Loadings section. The resulting monthly loading conditions are depicted below. The progression from low Condition numbers to high Condition numbers is an indication that Grand Island is growing into the Nebraska City #2 capacity and then outgrowing it.

Distribution of Unit Commitment Condition Numbers

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Jan	1	3	3	3	3	4	4	4	4	4
Feb	1	1	1	3	3	3	4	4	4	4
Mar	1	1	1	1	3	3	4	4	4	4
Apr	1	1	1	1	2	2	4	4	4	4
May	2	2	2	2	4	4	4	4	4	4
Jun	4	4	4	4	4	5	5	5	5	5
Jul	5	5	5	5	5	5	5	5	5	5
Aug	4	4	4	4	4	5	5	5	5	5
Sep	2	2	4	4	4	4	4	4	4	4
Oct	2	2	4	4	4	4	4	4	4	4
Nov	1	1	1	1	3	3	4	4	4	4
Dec	1	3	3	4	4	4	4	4	4	4

Figure 8

The year 2014 is the optimal production year. This year has the most Condition #3 and Condition #4 numbers, where participation eliminates the need to operate gas fired steam generation. In 2015 and beyond the months of June and August join July as Condition #5, where only direct production from Nebraska City #2 displaces natural gas generation. Under Condition #5 operation of Burdick Station steam generation will displace coal generation, regardless of participation. This reduces the savings that can be provided by Nebraska City #2 and is an indication that additional base load coal-fired capacity should be considered prior to that development.

Annual Load Duration Curves

<u>Reassembly of the Load Duration Curve</u>: Part #1 of **IRP, 2003** limited discussion to annual load duration curves. The examples were restricted to years in which operation of Burdick Station steam generation could potentially be avoided. Peaking generation, which follows load well, is stacked on base load generation, for an uncomplicated annual graph. Annual load duration curves lacked sufficient granularity to represent operation of intermediate generation in detail.

To show what happens, the monthly load duration curves are combined to form annual load duration curves for the years 2014 and 2019, both without and with participation in Nebraska City #2. These graphs are shown on the following two pages, Figures 9, 10, 11, and 12.

The comb effect on the center and right portions of the graph represents Burdick Station steam generation. Operated for an entire month, but not necessarily every month, Burdick steam generation appears intermittently.

For a given year, the difference between the dark shadings is the potential savings with a 30 MW participation purchase from Nebraska City #2. The year 2014 is shown because it represents the optimum configuration of resources. The year 2019 is shown because it is the last year of the study period.

2014 Load Duration Curves:

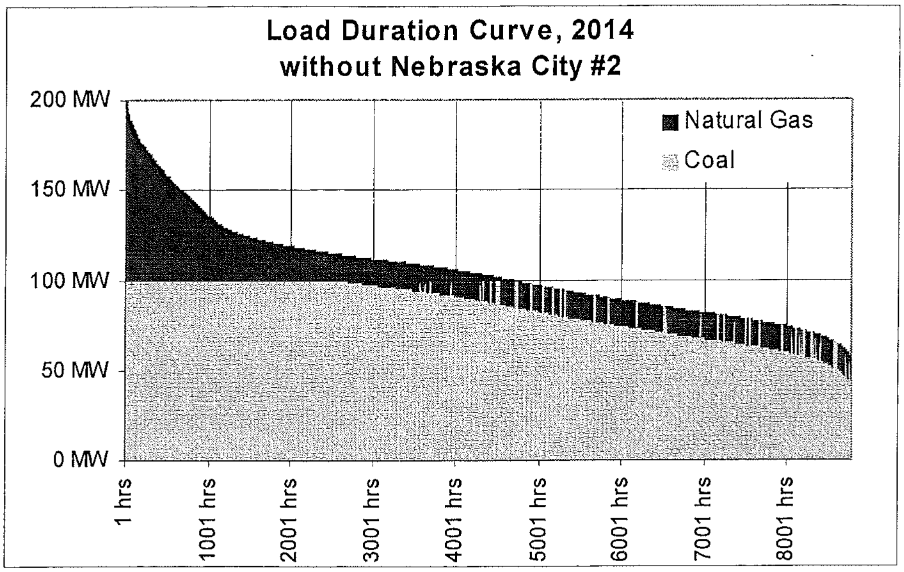


Figure 9

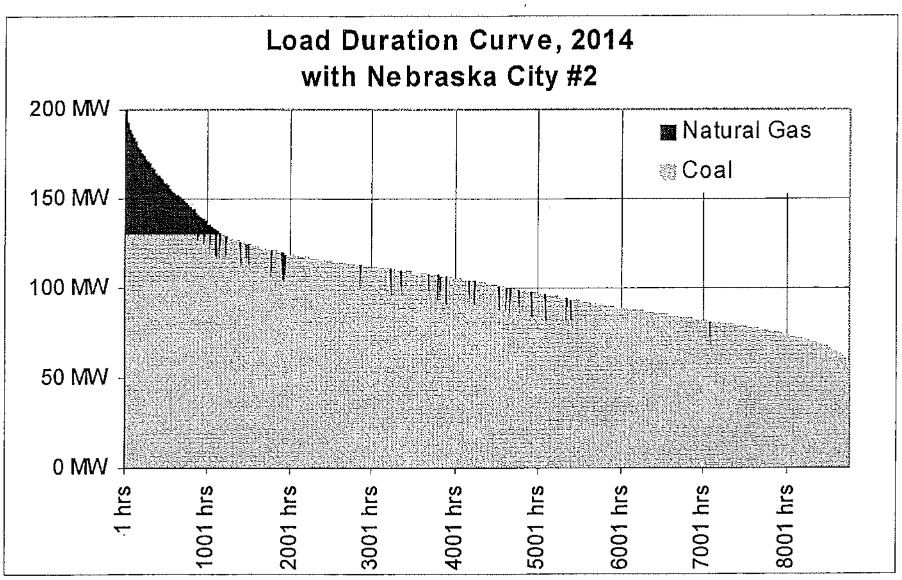


Figure 10

2019 Load Duration Curves:

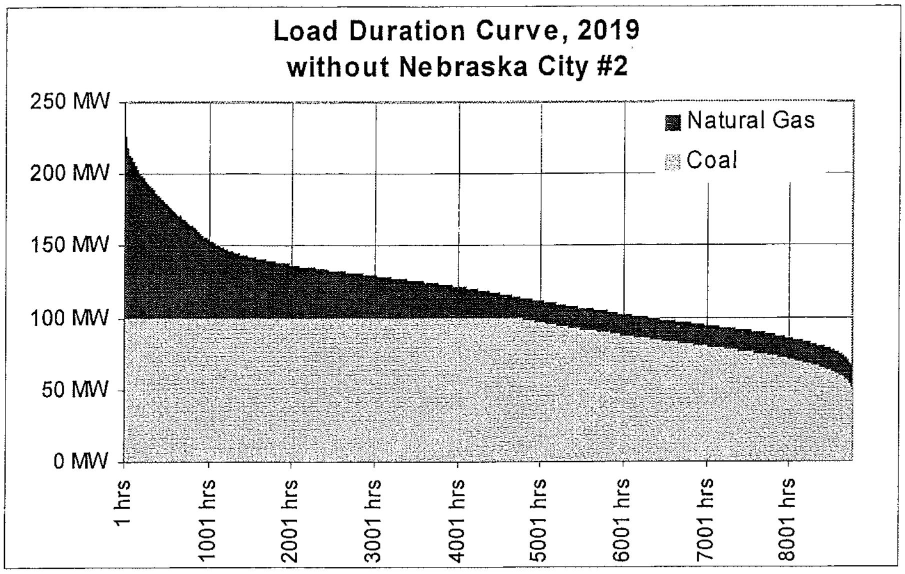


Figure 11

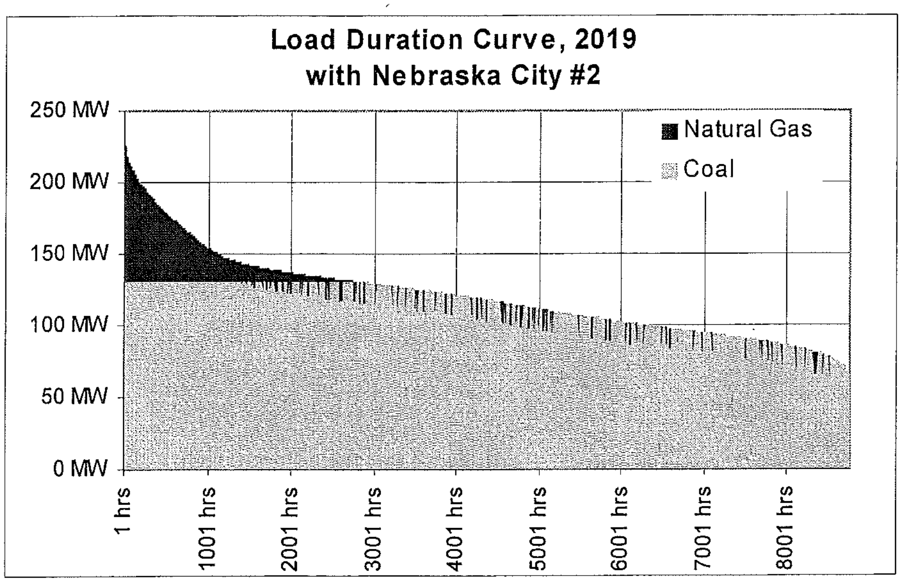


Figure 12

Savings

<u>Monthly Energy Savings</u>: Summary sheets for the monthly energy savings are provided in Appendix E. Each summary sheet begins with the peak monthly demand and monthly energy projections. The peak monthly demand is then transferred to a worksheet, corresponding to the month of interest. The calculation procedure is as follows:

(1) The peak monthly demand is used to scale hourly demands of the 2002 monthly load duration curve, which is internal to the spreadsheet. Succeeding operations are on load duration curves resulting from scaled hourly demands.
(2) Based on hourly demands generating units are operated, as described in the "Load Duration Curves" and "Unit Commitment" sections.
(3) The results are monthly load duration curves, each of which corresponds to a Condition number as defined in the "Unit Commitment" section.
(4) The areas of each defined section of the Condition curves are calculated. This gives the energy produced by generator type or condition.
(5) The various monthly energies are transferred to the annual summary sheet that contains the peak monthly demand and monthly energy rows.

Annual totals are then calculated on the summary sheet. The energy of concern through participation in Nebraska City #2 is provided in the row labeled "Total Coal Generation Displaced." This row is the sum of "New Coal/Burdick" and "Burdick Station, Displaced Coal" rows. (The term "New Coal" is used to facilitate modeling of other base load options.) Months falling under Condition #5 show zero in the "Burdick Station, Displaced Coal" row; this energy is included on the "Burdick Station, for Load" row.

As a check, the individual energy production areas are summed to a row labeled "Monthly Production." For comparison, the individual hourly demands are totaled to the row labeled "Monthly Load (check)." If there is no unaccounted for generation, these two areas will be equal.

Retail energy consumption is growing faster than the monthly peak demand. So the sum of hourly demands is less than the expected monthly energy needs, provided in the "Energy" row. Being non-peak, this unaccounted for energy primarily will fall in the base-load portion of the load duration curve; its omission understates the value of participation in Nebraska City #2.

The "Total Coal Generation Displaced" is gas fired energy that will be produced from coal-fired generation, should Grand Island participate in Nebraska City #2. The costs and cost difference is then calculated.

"New Coal" includes "Total Coal Generation Displaced" times $10,000 per GWh (i.e. $10 per MWh); to that is added the $2,622,515 annual capital payment. This is compared with "Burdick Station" calculated by multiplying "Total Coal Generation Displaced" by $70,000 per GWh (i.e. $70 per MWh).

<u>Annual Savings</u>: For each year of the study period, the "Total" production results are transferred to the "Summary of Annual Savings by Participating in Nebraska City #2" worksheet. The row "Total Gas Energy Saved" is equivalent to "Total Coal Generation Displaced" in the monthly calculations.

Annual costs are calculated as described in the previous section, except transmission expense of $1,440,000 is added to the cost of Nebraska City #2. Where appropriate, the savings are adjusted by a transmission credit of $1.50 per kWh-month from the Transmission Credit Account. With participation, the total annual savings exceed $37 million for the ten-year period. This is sufficiently above the "no savings" indifference point to demonstrate the need to participate in Nebraska City #2.

The annual savings are shown graphically below:

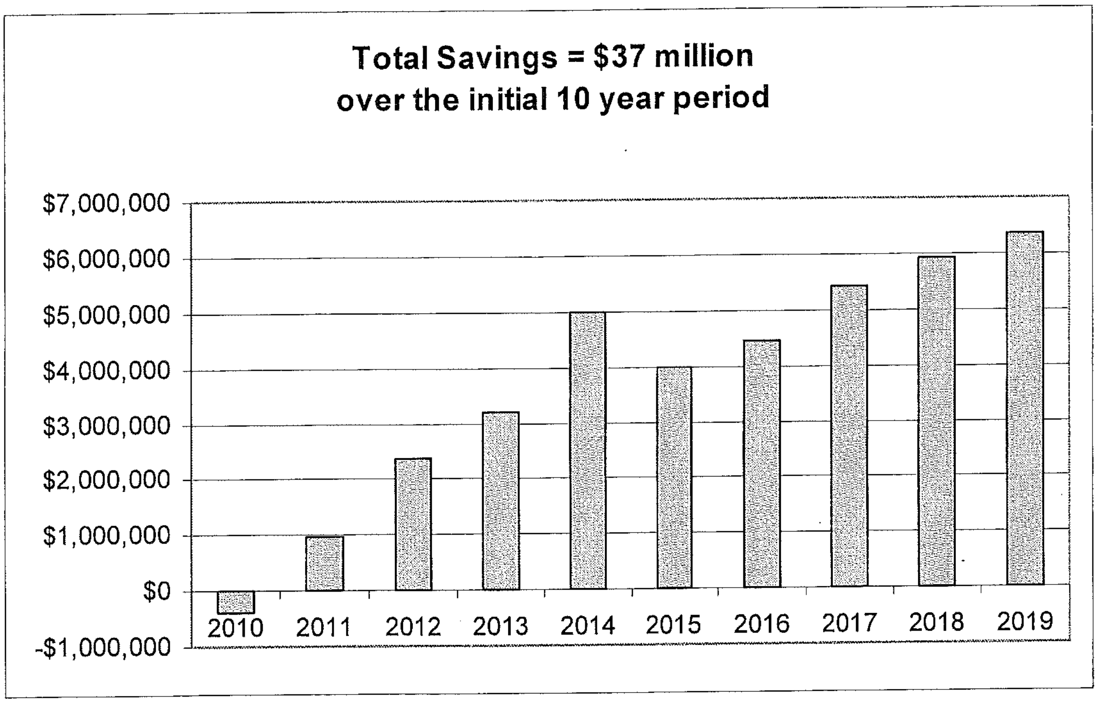


Figure 13

There is a savings peak in the year 2014, which represents the most efficient mix of Grand Island's generation. The simplified load duration curve of Figure 2 shows the Combustion Turbine peaking units stacked on top of base load coal-fired generation from Platte Generating and Nebraska City #2. During peak load conditions, each generator is operating at maximum capacity and there is no need to start the Burdick Station steam generation. In reality, various constraints prevent operating with no safety margins. These constraints include: weather uncertainties, hours-use Permitting limitations on the Combustion Turbines, and the requirement to maintain operating reserves. (Operating Reserves and resource pooling are discussed in **IRP, 2003;** Part #1.)

The more complex model of Part #2 considers operational constraints. Figure 8 and Figure 9 represent the division between coal-fired generation and natural-gas fired generation, for 2014, without and with participation in Nebraska City #2. Intermittent operation of Burdick Station steam generation produces a comb pattern on the right portion of the graph. With participation, natural gas consumption is drastically reduced and replaced by coal-fired energy.

Figure 12 shows a decrease in savings, beginning in 2015. Participation in Nebraska City #2 will not reduce the need for Burdick Station steam generation indefinitely. Once Burdick steam generation needs to supplement the Nebraska City #2 power, calculated savings are restricted only to the direct output of Nebraska City #2. Each year more energy will be taken from Nebraska City #2, so savings resume growth beyond 2015. Figure 10 and Figure 11 represent the division between coal-fired generation and natural-gas fired generation, for 2019, without and with participation in Nebraska City #2. The difference in the energies represented by dark shadings multiplied by the difference in total production, natural gas verses participation, costs represents the $6+ million annual savings for 2019 shown on Figure 12.

With participation, Grand Island will have some excess coal-fired energy, in the off-peak hours. Compared to other sources this is marketable low cost energy. The final two rows, on the Summary page of Appendix E, indicate that this energy may produce additional income, from sales, in the range of $1 million per year. These potential sales are excluded from the $37 million calculated in the economic analysis.

Measurement of Performance Objectives

Interpretation of Calculated Savings: The estimated savings are calculated to assist in decision making, not a prediction of future costs. Using current fuel prices, savings was based on difference in energy costs; calculations cease when the need for new capacity is recognized.

Based strictly on energy considerations, if no savings are realized, there is no benefit in participation. Had this been the result, the study could have been expanded to include the value of capacity. It is likely that the opportunity to participate would be ignored, without Public involvement, and no IRP would be submitted.

At the time of preparation only two alternatives are under consideration, participation or nonparticipation. The results are overwhelming in favor of participation.

Performance Objective: The **IRP Rules** are concerned about load projections. Grand Island's load projections are based on historical trending. Forecasts are updated, with the growth rate recalculated, after the end of each period, be it monthly or annual. If the actual loads consistently deviate from the trend, the beginning year will be changed and a new base established.

Since this is not a capacity study, "Acquisition of 30 MW additional capacity by the year 2010." is not a suitable performance objective. Depending on final assignments, the 30 MW requested may even vary somewhat.

The objective is to reduce future energy costs. It is difficult to construct a baseline for an event that will not begin until 6 years into the future. Using current fuel costs a savings of $37 million, over a ten-year period, is calculated. Since fuel costs were not projected, this is not a savings "projection" and should not be used as a performance objective.

The most valid performance measurement is relative energy costs. The energy costs, by unit type, are published monthly in the calculation of Grand Island's Fuel Adjustment. This measurement procedure will continue.

Cost of Unfulfilled Expectations: The premise of **IRP, 2003** is: "The cost of coal (per unit of heat content) will continue to be substantially less than the cost of natural gas." If this premise proves incorrect the basis for the participation recommendation will be erroneous. It will also be a marvelous illustration that being wrong can trump being right.

With participation, Grand Island will have approximately 130 MW of coal-fired capacity and 180 MW of gas-fired capacity. Should natural gas again become plentiful and cheap, the gas-fired units will then be operated as low cost base load generation. Grand Island will gain 50 MW of low cost generation with a low natural gas cost scenario. Coal units will operate at their minimum loading and the output increased for peaking duty.

Plentiful natural gas at a drastic reduction in price will cause the Grand Island Electric Department to be financially sound and environmentally benign until new capacity is needed in 2024.

Conclusion and Milestones

Conclusion: In Part #2, a more detailed analysis of participation was performed than was done in Part #1. From this analysis, it was determined that, using current fuel prices, a 30 MW participation in Nebraska City #2 saves $37 million, over the first ten full years of operation. This study interval was sufficient to demonstrate economic benefits of participation. Analysis ended in 2019 and the value of additional capacity was not considered.

Savings from participation will continue for the remaining expected 30-year life of Nebraska City #2. Sometime after 2014, additional base-load generation will again optimize the resource mix and lower costs. At today's rate of demand growth, participation in Nebraska City #2 will provide sufficient generating resources for Grand Island to meet its capacity obligation through 2024.

Milestones: Grand Island is participating in a generating plant constructed by another utility and has little direct control over the construction progress. The only milestone is to begin taking power and making payments, upon completion of Nebraska City #2. This is scheduled to occur in May 2009.

Grand Island, Nebraska
Electric Department

Integrated Resource Plan, 2001

March 2001

Introduction

Effective power supply planning demands frequent attention. Electric demand patterns are subject to change while supply side permitting and construction are time consuming. The Grand Island Electric Department (GIED, Grand Island, or Electric Department) routinely evaluates its demand and supply side options. This **Integrated Resource Plan, 2001** reexamines, in today's environment, the major options, from previous studies.

The conclusion is that the Electric Department should install two simple cycle combustion turbines, each with a nominal 40 MW net capacity. This conclusion is based on the following:

1. Considering the concern over global warming, the high capital costs for a small, locally constructed, coal-fired power plant represents an unacceptable risk.
2. Participation in the nominal 700 MW Iatan 2, coal fired power plant, is no longer an option.
3. With the great price disparity between natural gas and coal, the most cost effective fuel strategy is to minimize the use of natural gas. Gas generation should not displace energy that would otherwise be produced by coal-fired generation.
4. Based on the load duration curve for Grand Island, the optimal method for supplying the projected electrical demand is through the addition of 80 MW of simple cycle combustion turbine peaking capacity.
5. Two 40 MW simple cycle combustion turbines will result in fewer emissions and provide greater reliability than would a single 80 MW combustion turbine.
6. In the event that base-load natural gas generation becomes more economically feasible than coal-fired generation, the combustion turbine addition can be converted to efficient combined cycle operation.

Grand Island Electric Department

Description of Utility: The Grand Island Electric Department is a municipal utility owned and operated by the City of Grand Island, Nebraska. The Electric Department serves 22,000 meters within an 80 square mile Service Area. The distribution voltage is almost exclusively 13.8 kV.[1] Generating plants and distribution substations are interconnected by a 115 kV loop. During the year 2000, the average retail rate was 4.7 ¢/kWh.

System Load and Load Projections: Grand Island is a summer peaking utility, in August 2000 the peak annual demand of 146.5 MW occurred. The December peak demand was 93.8 MW. Total system energy requirements for calendar year 2000 were 632,516 MWh, retail sales were 598,637 MWh, resulting in 5.4% system losses. Using a combination of switched and fixed capacitors, the system power factor, during high demand periods, approaches unity.

Grand Island uses historical trending for load projections. The base year for the projections is 1978, this year was selected because it avoids the 9% growth years prior to 1973 while skipping the uncertainties of the mid-1970's. Demand and energy projections are prepared for each month. Annual energy and minimum demand projections are also prepared. The Department regularly monitors these data in order to disclose any unexpected trends that would force reevaluation of the projection method. (See Appendix A[2])

[1] A few miles of 7200 volt rural distribution circuits remain. They are being converted to 13.8 kV.

[2] Data for the calendar year 2000 are included at this point, because they are the most current. Decisions made during 2000 were base upon calendar year 1999 data, which is referenced elsewhere in this **Integrated Resource Plan, 2001**.

July is the expected month for the summer peak; July demand growth rate is 2.49%. The actual demand is extremely temperature dependent; capacity planning considers potential maximum temperatures.

December is the expected month for the winter peak; December demand growth rate is 3.06%. As with the summer peak, there is a strong correlation between temperature and the winter peak demand. This is a reason for concern. Comparing the winter heating temperature differential with the summer cooling temperature differential, one can estimate the potential winter demand exceeding the summer peak demand by a factor of two or three. Therefore, the Electric Department does not promote electric heat.

Eventually, there must be a change in growth trends. The annual energy usage and minimum demands fit well to the projection curves. Energy growth is projected at 3.27% and the minimum demand is 3.57%. The difference in these trends cannot be maintained indefinitely. In the very long term, growth of minimum demand cannot exceed either growth in peak demand or energy sales and projection trends will change.

Resources: To supply the peak demand obligation, Grand Island owns the following generating resources:

Burdick Station Steam Turbines (Gas / #6 Oil fired)		
Unit #1	(1957)	16.5 MW
Unit #2	(1963)	22.3 MW
Unit #3	(1972)	54.0 MW
Burdick Station Combustion Turbine (Gas / #2 Oil fired)		
GT #1	(1968)	14.8 MW
Platte Generating Station (PGS) Steam Turbine (Coal fired)		
PGS #1	(1982)	100.0 MW

GIED also has a 9.168 MW firm power allotment from Western Area Power Administration.

Previous Studies

Burns & McDonnell: The 1992 **Future Power Supply Study** by Burns & McDonnell concludes: "Installation of coal-fired generation in the early 2000s would allow GIED to most economically meet its future power supply requirements. Following a coal-fired plan also appears to reduce risks on the sensitivity analysis performed. Implementation of load management may allow GIED to delay the installation of new generation, but it will not change the recommendation to pursue coal-fired generation."

GDS Associates: In compliance with the Energy Policy Act of 1992, the Western Area Power Administration required that customers submit Integrated Resources Plans, at regular intervals. Grand Island hired GDS Associates, Inc. of Marietta, Georgia to perform an exhaustive study and prepare the Integrated Resource Plan (IRP). This plan was completed in December 1996 and adopted by the City Council on April 14, 1997.

The Integrated Resource Plan adopted by the City Council studied 56 conservation options, 3 load building options, 2 load management options, and 18 supply-side options. "To implement the City's preferred Integrated Resource Plan, the following steps will be taken during the upcoming five years:

1. Immediately, develop a preferred size and a refined cost to construct an additional coal-fired generating unit at the Platte Generating Station.
2. Immediately, develop a refined estimate of the revenue likely from the sale of all capacity and energy in excess of 50 MW from the new Platte Generating Station unit to other utilities.
3. Immediately, solicit confidential proposals from all prospective suppliers to provide 50 MW of coal-fired capacity and energy beginning in 2004.

4. Fully develop the power purchase options and negotiate the best possible arrangement for Grand Island. This must be completed during 1997.
5. If participation in the Iatan 2 project is selected, a delay in the commercial operation of Iatan 2 is possible. If this event occurs, consider the Air Conditioning Load Control Program and/or a short-term power purchase contract from NPPD or another utility.[3]
6. Collect information on Air Conditioning Load Control Programs that are implemented by other utilities and information on emerging technologies for such programs.
7. Renew Grand Island's power purchase with the Western Area Power Administration (WAPA)."

Power System Engineering, Inc.: In 1997 Grand Island renewed the power purchase Contract with WAPA and also solicited proposals from engineering firms to assist with otherwise implementing the Integrated Resource Plan, specifically implementation steps 1 through 5.

Power System Engineering, Inc. (PSE) from Madison, Wisconsin was awarded the task of implementing the IRP. Significant progress was made in steps 1 through 4. Iatan 2, sponsored by KLT Power, Inc. and Black & Veatch Power Development Corp., was clearly the preferred alternative. Step 5 recognized a potential delay with the construction of Iatan 2. Then, at a February 3, 1999 meeting, in Lincoln, KLT Power Inc. informed potential participants that the project was postponed.

The Grand Island load growth cannot accommodate a four-year capacity delay through an air conditioning load control program. PSE completed, as far as possible, the tasks for which they were hired. The Implementation Plan could not be finished. The Electric Department is forced to examine other alternatives.

The 1996 Integrated Resource Plan was the result of an exhaustive two-year study. The 1996 IRP steered the Electric Department in the direction of a supply side addition. However, the preferred alternative, Iatan 2 participation, was a dead-end. In 2001, 1996 IRP is updated to look for what is changed and unchanged from the initial plan. The unchanged items will be considered first.

Unchanged Since 1996 IRP

Conservation Programs: Due to the low electric rates, conservation programs would require incentive payments. The expected result was a 2.3% decrease in demand and a 1% decrease in energy. A conservation effort will not change the year in which additional capacity is needed, so no benefit would accrue to the Electric Department.

Incentive payments would come from electric revenue, with only a minor offsetting decrease in expenses. Implementation of conservation programs will only increase electric rates. Electric rates remain low and with proper planning are expected to be stable.

Load Building: The goal of load building is to increase utilization of capital investment, by promoting off peak energy use. This is happening with the current rate structure and growth pattern. The 2.49% peak demand growth is less than the 3.27% annual energy growth rate. The minimum demand growth rate of 3.57% exceeds the energy growth rate. Appliance and air conditioner efficiency standards reduce the growth in peak demand. Efficient appliances and "always-on" devices increase the growth in off-peak demand.

Load Management: Load management is appropriate for a utility purchasing power at wholesale, where peak demand is purchased incrementally and ratcheted during the off-peak months.

[3] Iatan 2 is a proposed 700 MW, multi-owner, power plant to be constructed near Weston, Missouri.

A generating utility installs plant capacity in blocks, rather than in annual incremental amounts. Once installed, the entire plant addition can be available for customer use. Load management will not produce a sustained benefit; it only delays construction. By using active air conditioner control, the Electric Department may attempt to delay a plant addition by two years. However, the inherent uncertainty in demand projections, from year-to-year, is larger than the air conditioner control reduction.

Grand Island attempts to plan for the 90th percentile of summer temperatures, which is 109° F. If installed, there is a one in five chance that active air conditioning control would be needed. During years of excess capacity, air conditioning control will remain idle as a non-producing investment.

In the past thirty years, air conditioner sizing has become a science and units are no longer oversized. This makes the air conditioner load self-limiting. Under extreme temperatures, air conditioners stop cycling, presenting a constant, rather than temperature sensitive, load.

Purchased Power Options: There continues to be a dearth of surplus power offered for sale within the region. In the absence of Iatan 2, the Electric Department has not received an extended term, competitive, quantifiable offer for power and energy beginning in 2004.

GDS solicited fifty utilities in a nine-state area, which revealed only two potential sources for purchased power. The offers were from Nebraska Public Power District (NPPD) and KLT Power, Inc. The KLT Power response was for Iatan 2. The NPPD response offered participation power beginning in 1996 and terminating in 2005; this did not fit Grand Island's need for additional capacity beginning in 2004.

Power System Engineering sent solicitations to ten generating utilities within MAPP. Only NPPD responded. This response was based on a proposed gas-fired, combined cycle unit. The proposed capacity charge approximated debt service on the project. Energy costs would include fuel, variable O&M, and losses. If constructed outside Grand Island's Service Area, transmission charges would add approximately 30% to the capacity charges; this single item makes the offer unattractive. Although NPPD was flexible with the quantities and term, there was no Grand Island ownership associated with the proposal; eventually the Electric Department would need to find a replacement resource.

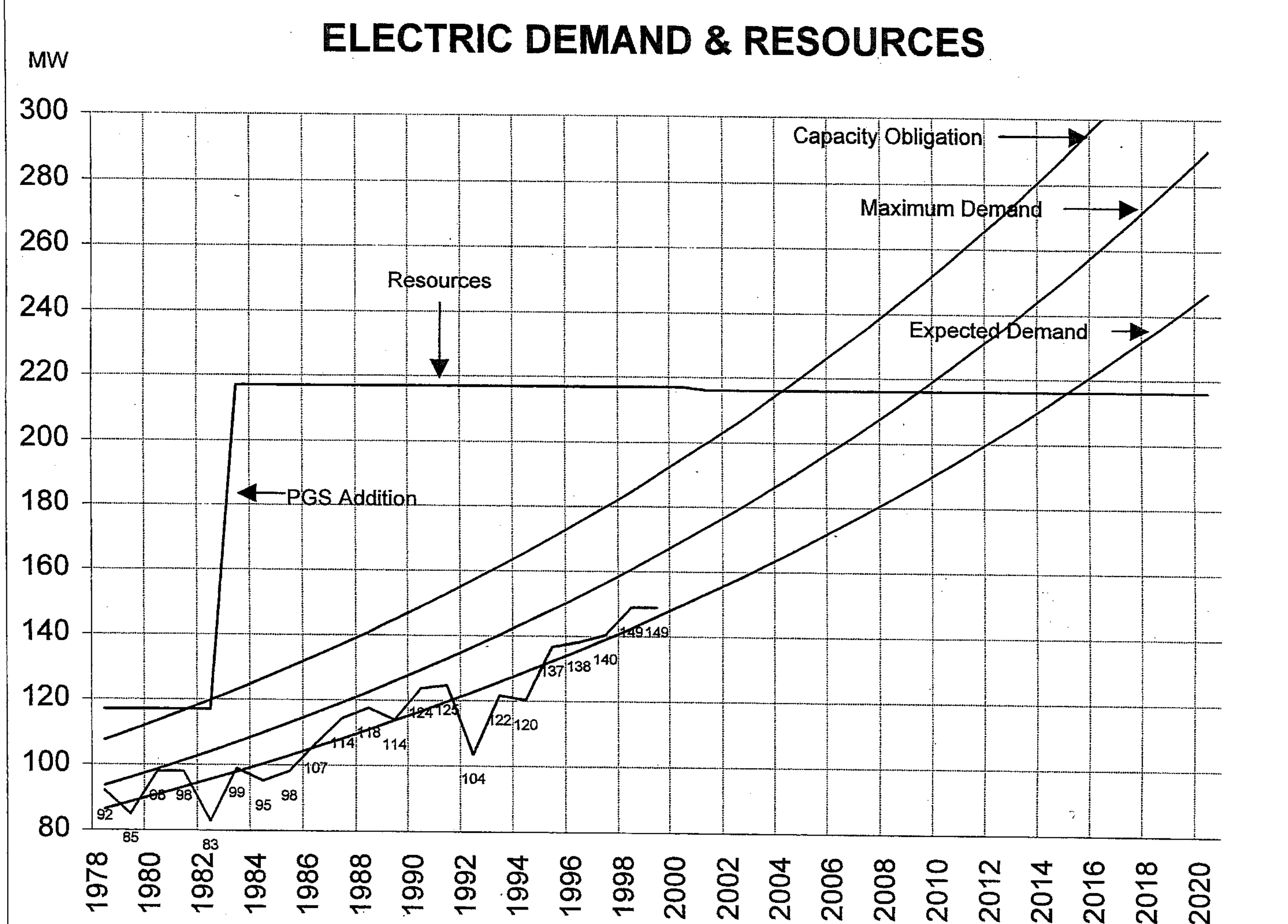
Grand Island works closely with NPPD, both in planning and operation. There have been several discussions between the two utilities. The most recent explored the prospect of NPPD purchasing capacity from Grand Island, should the Electric Department install combustion turbines.

Non-Traditional Supply Side Options: Among the non-traditional supply side options considered, and ruled out, by GDS, in the 1996 IRP were: (1) Integrated Gasification Combined Cycle, (2) Pressurized Fluidized-Bed Combustion, (3) Evolutionary Nuclear Reactor, (4) Pumped Storage Hydro, (5) Compressed Air Energy Storage, (6) Advanced Batteries, (7) Superconducting Magnetic Energy Storage, (8) Fuel Cells, (9) Solar Photovoltaic, (10) Wind, (11) Municipal Solid Waste, and (12) Biomass. There have been insufficient changes, either technological or site specific, to make any of these alternatives a viable supply side option.

Grand Island remains interested in non-traditional supply side resources, and is willing to support them. In December 1996, Grand Island, and other utilities, had the opportunity to participate in the EPRI/DOE Turbine Verification Program, Phase III. NPPD is the sponsor of the project, which eventually became known as Nebraska Distributed Wind Generation (NDWG) Project. The Electric Department is a participant.

Need for additional Supply Side Capacity by 2004: The need for new capacity is shown graphically on Figure 1. The Maximum Demand Trend line is based on the annual variation between actual and expected demand.

The 1999 anticipated Maximum Demand, from Figure 1, was 165 MW. That summer, the temperature, as recorded at the Dispatch Center, reached 103° F, the peak electrical demand was 149 MW, and the demand


ELECTRIC DEMAND & RESOURCES
MW
300
280
260
240
220
200
180
160
140
120
100
80
Capacity Obligation
Maximum Demand
Expected Demand
Resources
PGS Addition
92
85
98
98
83
99
95
98
107
114
118
114
124
125
104
122
120
137
138
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149
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2018
2020

Figure 1

was increasing at 2.5 MW/F°. Had the temperature been 7° F higher, or 110° F, the demand would have been 17 MW more, or 166 MW. Therefore the Maximum Demand Trend line represents the electrical demand when the temperature is about 110° F.

The continental United States and Canada are divided into Regional Reliability Councils. Grand Island is subject to the operating procedures of the Mid-continent Area Power Pool (MAPP). Through interconnected operation, utilities can pool reserves. Within the MAPP region, a Planning Reserve of 15% is required. Grand Island's Capacity Obligation is 15% more than the maximum demand.

In 1936 the temperature in Grand Island was 117° F, at some date this record temperature will be exceeded. If the load vs. temperature relationship remained linear, the maximum demand at 117° F would be 184 MW, or 12% above the maximum design temperature of 165 MW. This event is very unlikely; Grand Island would be fined by MAPP, for failing to maintain the Planning Reserve margin, but there would be no curtailment to retail customers.

On Figure 1, the line representing the Electric Department's generating resources intersects with the Capacity Obligation curve in 2004. The Electric Department continues to need additional capacity by the year 2004. The amount and type of generation is the major topic in this update of the 1996 **Integrated Resource Plan**.

Changes Since 1996 IRP

Kyoto Protocol: Many scientific studies appear to measure an increase in the average global temperature. This trend has been correlated with an increase in atmospheric CO_2, which is termed a greenhouse gas because it reflects infrared radiation back to the surface of the earth. Combustion of fossil fuels is a major contributor to the atmospheric CO_2.

The **Integrated Resource Plan** was prepared in 1996 and adopted by the Grand Island City Council in April 1997. In December 1997 the United Nations Framework Convention on Climate Change agreed to the Kyoto Protocol. To become enforceable, 55 countries, accounting for at least 55% of the total 1990 CO_2 emissions for developed countries must ratify it. So far the U.S. Senate has not consented to the Kyoto Protocol; but 84 Nations have signed the agreement.

Should the Kyoto Protocol become enforceable, by 2012 the United States must reduce its carbon dioxide emissions to 7% below the 1990 emission level. This will have a significant impact on the use of coal as fuel. When burned, coal produces approximately twice as much CO_2 then does natural gas, for the same amount of heat output.

The use of coal in existing power plants eventually may be restricted. Coal fired generation is very capital intensive. Until the global warming issue is resolved, the long-term wisdom of making the high capital investment required for new coal fired generation must be questioned

Iatan 2 Postponement: As part of the IRP implementation Power System Engineering compared capital costs between an addition at Platte Generating Station and the proposed Iatan 2 project. An addition to PGS was 50% higher cost than was Iatan 2, making Iatan 2 the preferred alternative.

The, previously mentioned, Iatan 2 project remains an uncertain but potential resource. The earliest it could become available is 2007. Air Conditioning Load Control will not accommodate a delay until 2007,

Grand Island must reexamine other conventional supply side alternatives. Lack of lead-time, pending Kyoto Protocol restrictions, and high capital cost prevented further consideration of the self-build coal option. The Electric Department then evaluated natural gas-fired generation.

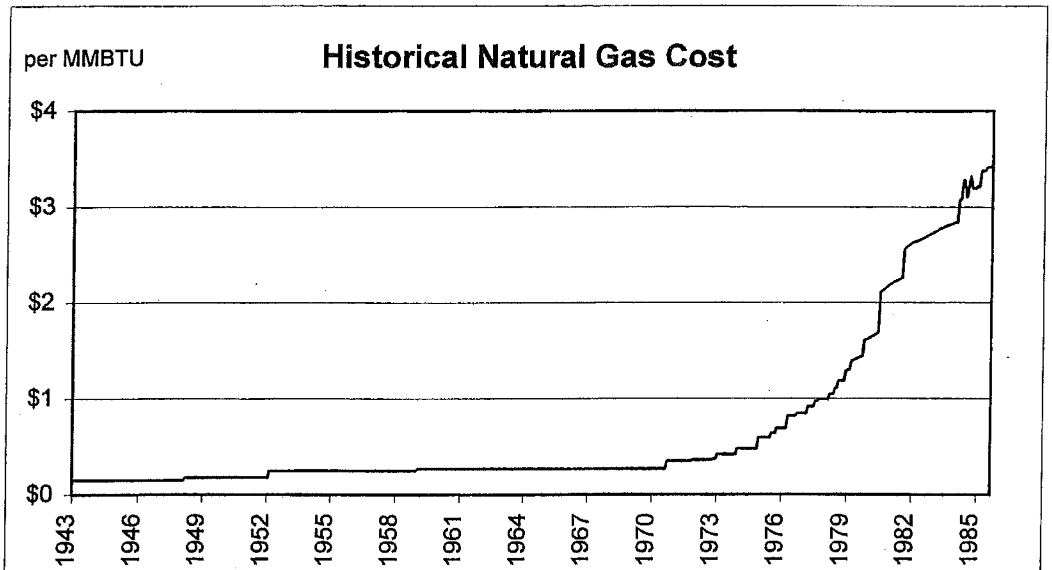

Figure 2

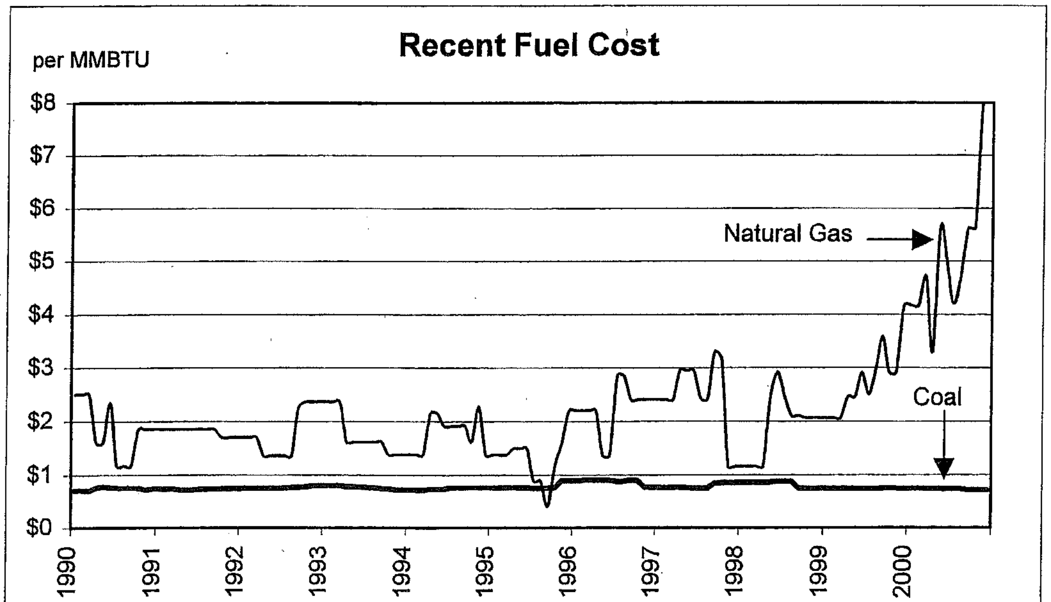

Figure 3

Natural Gas Cost and Availability: In 1972, when the natural gas cost was $0.35/MMBTU, the Electric Department added the 54 MW Burdick Station Unit #3. Over the next few years the price started to climb, as shown on Figure 2. The gas supplier initiated action to remove the pipeline serving Burdick Station. Through extended legal action, the pipeline remained. But for many years natural gas was, for practical purposes, unavailable.

Utilities must pay close attention to natural gas prices. Electric space heating may create an unexpected electrical demand. More recent prices for natural gas are plotted on Figure 3. During the winter of 2000-01, natural gas for residential heating surpassed $0.80 per therm; Grand Island's residential electric rate is $0.791 per therm, for consumption over 1,000 kwh.

Also plotted on Figure 3 is the coal cost as experienced by the Electric Department. The basis of the strategy selected by Grand Island is that energy produced by coal-fired generation will be a small fraction of the cost of energy produced by gas-fired generation. The drastic disparity in fuel cost is likely to continue until 2012, when the Kyoto Protocol, and a resulting carbon tax, may become effective.

Since the only expansion option is gas-fired generation, the strategy is to select the type of generation that will permit the Electric Department to minimize natural gas and/or fuel oil consumption. Fortunately, the type of gas-fired generation that fits this strategy also has the lowest capital costs.

Minimizing Natural Gas Consumption

Methodology: From past studies, current engineering design, and recent energy prices, the below figures illustrate the wide variations in capital and fuel costs for coal-fired steam turbine and gas-fired combustion turbine power plants.

Natural gas generation construction cost	$635 / kW
Coal-fired generation construction cost	$1,450 / kW
Natural gas fired energy cost	$60 / MWh
Coal-fired energy cost	$12 / MWh
Annual debt service as fraction of debt	10%
Minimum load on Brudick steam generation	12 MW

Optimizing Use of Platte Generating Station: The obvious method for minimizing natural gas consumption is to generate exclusively using coal. The coal-fired Platte Generating station lacks sufficient capacity to serve the peak demand, and, for the present, adding coal fired generation presents excessive risk. Minimizing natural gas use is achieved by maximizing the production from Platte Generating Station. The bulk of the energy production should come from the base load, coal fired, plant.

The 1999 load duration curve for Grand Island is on Figure 4. A load duration curve represents the City load for each hour of the year, sorted and graphed by demand, rather than the hour in which the demand occurred. Using a load duration curve greatly simplifies the modeling process. The shape of curve varies only slightly, from year to year. The area under a normalized (divide every point by the maximum demand) load duration curve is the annual system load factor.

Since the shape of the curve is essentially constant, the curve can be normalized and then rescaled to represent any given maximum demand. Energy production is directly proportional to fuel consumption, so the area below the knee of the curve should be satisfied with the lowest cost generating resources.[4]

[4] To simplify the process, operating reserves and the WAPA Firm purchase are not shown because operating reserves are offset by the WAPA purchase.

Load Duration Curve 1999

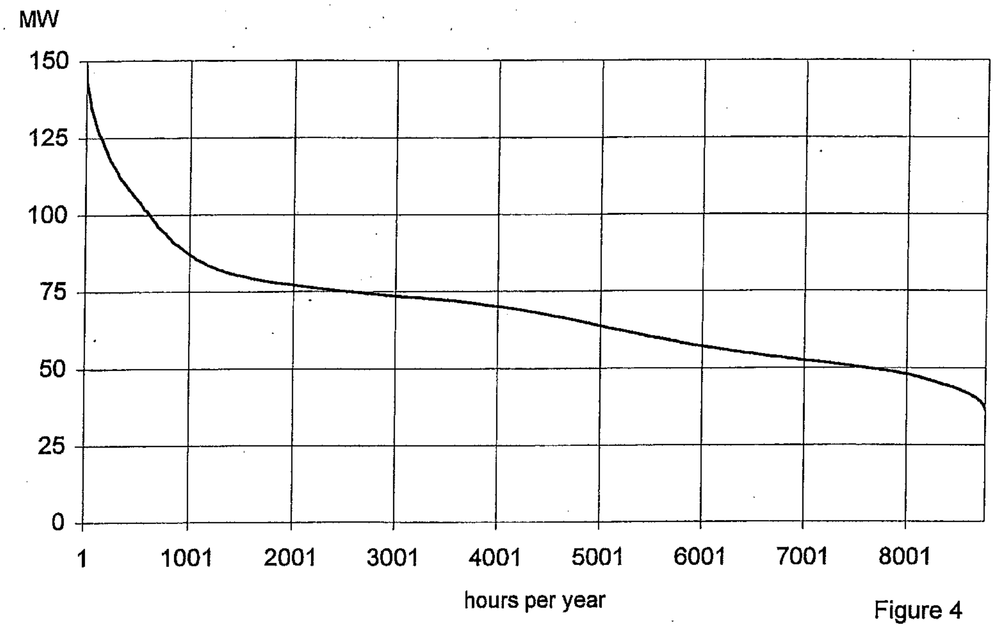

Figure 4

Normalized Load Duration Curve

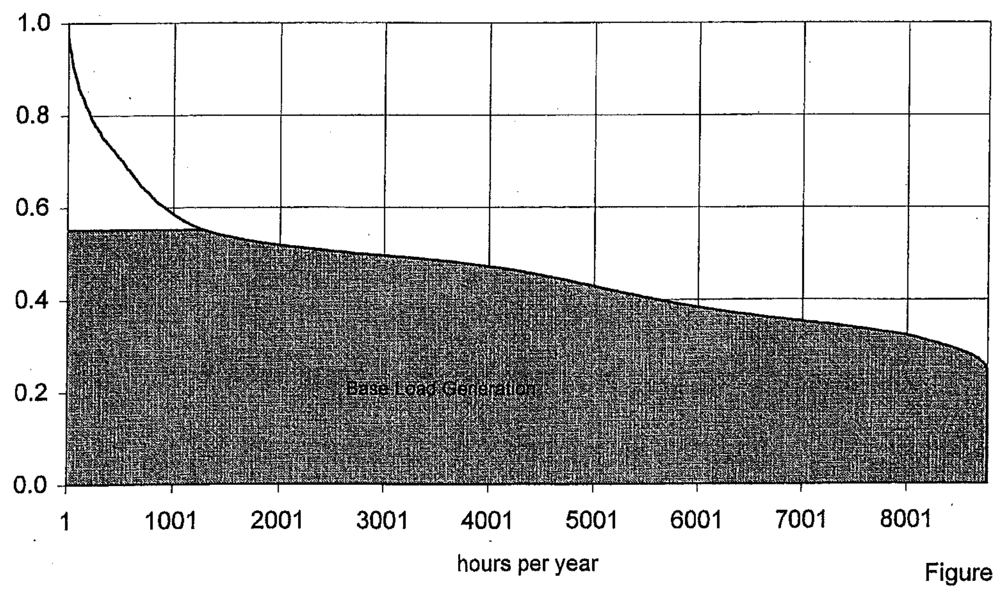

Figure 5

The horizontal line drawn across the knee of the normalized load duration curve, in Figure 5, represents optimized use of base load generation, or Grand Island's 100 MW coal-fired Platte Generating Station (PGS). By rescaling the normalized load duration curve so that the horizontal line equals 100 MW, the peak becomes 182 MW. Therefore, the most efficient use of PGS will occur when the peak demand is 182 MW. Referring to the load projections, Figure 1, this condition will exist in 2008.

Status Quo Natural Gas Consumption: Figure 6 represents the 2008 load duration curve. Total sales will be 733,641 MWh. Ideally, the Platte Generating Station will produce 701,091 MWh, filling the base of the curve. The remaining 82 MW demand and 32,550 MWh energy must be filled by some type of generation.[5, 6, 7]

The Burdick Station gas fired steam generation totals 93 MW. These three units were installed between 1956 and 1972; in those times, natural gas was an inexpensive fuel. The Burdick Steam units were designed as base load generation; that natural gas is now expensive does not change design limitations. Steam turbines are not suitable for frequent, repeated thermal cycling. Such operation significantly shortens turbine life by creating cracks in the turbine shell and rotor. Thermal cycling limitations require the steam turbines to be operated at some minimum load (about 20% of full output), rather than shutting them down, daily, when the output is unneeded.

With the minimum output and run times, Burdick Station steam generation cannot be operated in a peaking mode. In the process of satisfying the peak load, gas fired generation intrudes into the portion of the load duration curve, that ideally would be filled by base load, i.e. coal, generation. In 2008, the load exceeds 100 MW every month of the year. If Burdick steam generation supplies this energy shortfall, it will be operated 5,720 hours. Figure 7, shows the intrusion of high fuel cost Burdick steam units into the area that would otherwise be served by low fuel cost PGS. The total energy supplied by Burdick Station in 2008 is 89,723 MWh, at a cost of $5,383,380.

If gas-fired generation is restricted to satisfying only the 32,550 MWh peak load, peaking energy cost would drop to $1,953,000. The cost for PGS to fill the 57,173 MWh intrusion is $686,076. Increasing the cost, for the 89,723 MWh, to $2,639,076. So, if PGS is paired with Burdick Station steam generation to meet the energy needs in 2008, the intrusion of gas-fired generation into the base load area amounts to an unnecessary expenditure of $2.7 million. In the years before 2008, the expected savings are less, but after 2008, near maximum savings continue.

Generation that can be started and stopped on a daily basis is needed. This permits the peak of the load duration curve to be filled, without impacting the output of Platte Generating Station. Simple cycle combustion turbines have the desired operating characteristics. A combustion turbine addition will permit natural gas consumption to be minimized, which is the selected expansion strategy.

Simple Cycle Combustion Turbine: An 80 MW combustion turbine addition permits optimum use of the Platte Generating Station. Capital costs for combustion turbines are half those for coal-fired power plants. After allowing for maintenance costs, a combustion turbine addition reduces annual fuel expenditures by

[5] A supply side addition is necessary in 2004 to ensure that Grand Island has sufficient generation to serve the maximum expected electrical demand and to satisfy the 15% MAPP Planning Reserve obligation. The present analysis reflects a normal summer.

[6] Maintenance outages are not included in the analysis. Maintenance is generally performed in the shoulder months, when economy energy can be purchased from neighboring utilities.

[7] The existing 14.8 MW combustion is considered as part of the total combustion turbine capacity.

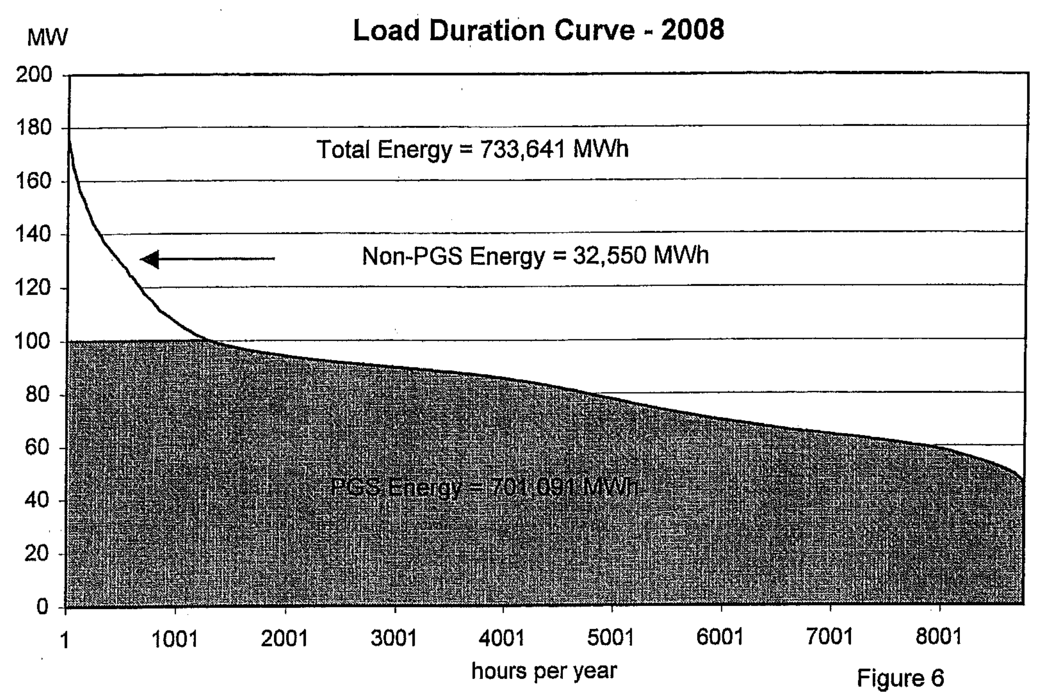

Figure 6

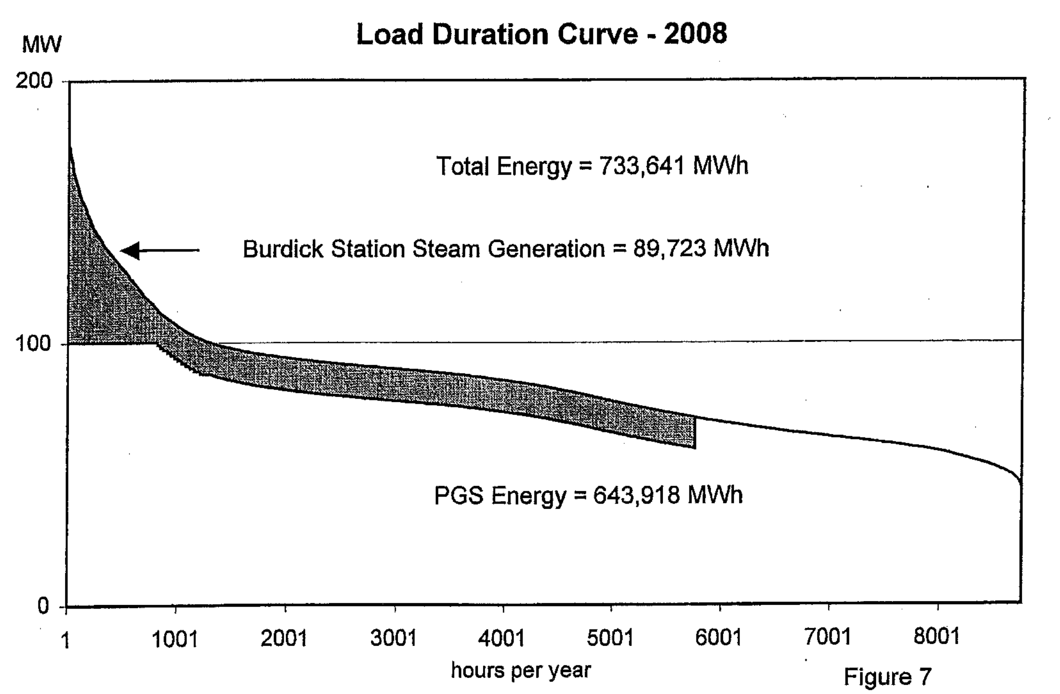

Figure 7

nearly $2 million. Considering a $5.3 million annual debt service produces a $2 million annual fuel savings, the economic efficiency of the Electric Department will benefit.

For reliability and environmental reasons, two nominally rated 40 MW combustion turbines are selected. The 32,550 MWh energy production can be accomplished by one CT operating for 1,300 hours, producing 28,550 MWh, and the other CT operating for only 300 hours and producing 4,000 MWh. Failure of a single 40 MW combustion turbine results in a 12% loss of energy needs. Failure of a single 80 MW combustion turbine results in loss of the entire peaking capability. Additionally, combustion turbine emissions are load dependent. Two 40 MW units allow for greater flexibility in matching optimum turbine loading to demand.

Plant Type Comparisons: This analysis is a comparison between high capital cost coal generation and high fuel cost gas generation, based upon the projected GIED load pattern.

	Coal (80MW)	Combustion Turbine (80MW)
Capital cost	$1,450,000 per MW	$635,000 per MW
Capital investment	$116,000,000	$50,800,000
Annual debt service	$11,600,000 per year	$5,080,000 per year
Energy production cost	$12 /MWh	$60 /MWh
Annual energy cost	$390,600 per year	$1,953,000 per year
Total cost	$11,990,600 per year	$7,033,000 per year

In 2008, with an energy need of 32,550 MWh, the annual cost of a coal-fired addition exceeds that of a combustion turbine addition by $4.9 million. Past 2008 the savings may be reduced. However, with the uncertainty imposed by the Kyoto Protocol and concerns with global warming, there is substantial risk in assuming that coal-fired energy will remain low cost.

By 2016 additional capacity will be needed.

Authorized Combustion Turbine Project

Selection of Consulting Engineer: After an August 22, 2000 presentation, the Grand Island City Council, by unanimous vote, authorized the Electric Department to proceed with the acquisition of two nominally rated 40 MW simple cycle combustion turbines. Six consulting engineering firms responded to a Request for Proposals. On October 10, 2000, the City Council hired Sargent & Lundy, of Chicago, Illinois, for combustion turbine engineering services.

Combustion Turbines: Specifications have been prepared for two, nominally rated, 40 MW combustion turbines. Two 40 MW combustion turbines were selected, in preference to a single 80 MW unit, after consideration of reliability, operating efficiency, and emissions.

The operating characteristics of a combustion turbine are such that efficiency increases and emission rates decrease as they become more fully loaded. Continuing to use the 32,550 MWh and 1,300 hours as a reference, a single 80 MW CT would have an average load of 31%. Using two 40 MW CTs, loaded as described in the reliability discussion, the CT running for the 1,300 hours will experience an average load of 55%. The CT being operated for 400 hours will be loaded to the 33% level.[8]

Siting and Natural Gas Supply: Adequate space for the proposed addition is present on an existing power plant site, the Burdick Station facility. A natural gas pipeline, sufficient for the existing 107 MW of capacity, already serves Burdick Station. Discussions with potential gas suppliers and pipeline owners are in progress. The Burdick Station complex also contains fuel oil storage tanks. Having storage for #2 diesel as an alternative to natural gas will give the Electric Department a hedge against fuel price and availability.

The combustion turbines and associated step-up transformers are located just to the east of the Electric Department's existing 115 kV Cherry Street Substation. No major problems are anticipated with substation expansion. This is also a distribution substation serving a large portion of central Grand Island.

The existing 14.8 MW Burdick GT1gas turbine is a black-start unit. In the event of a regional power outage, the output from Burdick GT1 will start the proposed combustion turbines, which are, in turn, large enough to start any of Grand Island's steam generating units.

Financing and Rates: The Platte Generating Station bond issues, in 1977 and 1979, totaled $80 million, originally for a 30-year term; a September 2014 retirement. These bonds were refinanced in 1992 and 1996 to advance retirement to September 2000. This was done in anticipation of financing continued power plant additions.

The Electric Department operates interconnected with Nebraska Public Power District at 115 kV. Beginning in 1982, the limitations of the NPPD 230/115 kV transformers were recognized, and modifications were initiated to correct transmission deficiencies. In December 1999, Grand Island and NPPD agreed that the Electric Department would finance NPPD's replacement of the undersized transformers. The financing would be credited as prepaid transmission expenses, to be used by Grand Island over a 15-year period.

In July 2000, Grand Island issued revenue bonds for $6,145,000. This issue is scheduled for retirement in August 2010. In essence, it causes the transformer payments to coincide with the transmission benefits that will be received. The transformer replacement is scheduled for completion during autumn of 2001. With the larger transformers, the Electric Department will be able to import sufficient power to serve its electrical load.

After buying out of onerous coal and freight contracts in 1988, the Electric Department revamped retail rates, lowering them an average of 13%. Since February 1989, electric rates have remained unchanged. In FY 1990-91 the annual income was $23,806,322, in FY 1999-00 the annual income was $29,127,367.

Grand Island's average electric rate is 12% below the average rate for Nebraska customers and 29% below the National average. See Figure 8. The proposed expansion plan is designed to maintain this competitive position.

Cost of the combustion turbine addition is estimated to be $50.6 million, to be financed over a 15-year period. The electric rate structure permitted retirement of the $80 million PGS bonds in 15 years; it will support retirement of $56 million over a fifteen-year period. Financing this capital improvement project will not require a rate increase.

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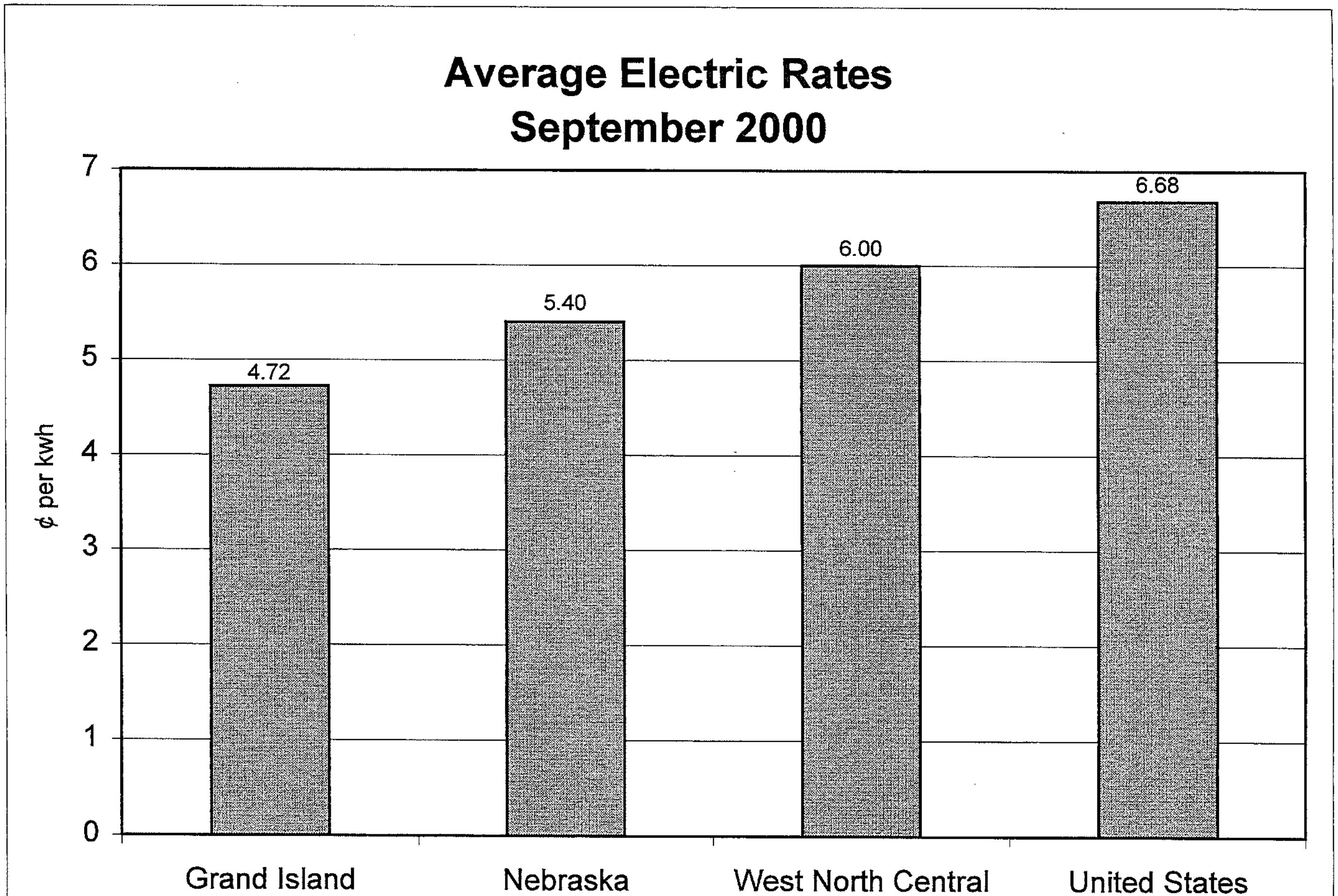
[8] Not discussed is the advantaged gained by operating the existing 14.8 MW combustion turbine. Neither CT is likely to be loaded to less than 10 MW. So the average load of the new turbines will be noticeably higher than calculated.



Average Electric Rates
September 2000
¢ per kwh
0
1
2
3
4
5
6
7
4.72
5.40
6.00
6.68
Grand Island
Nebraska
West North Central
United States

Figure 8

A Fuel Adjustment provision in the Electric Rates has been in effect since 1973. It permits the Electric Department to pass unusually high fuel related expenses on to the customers, without City Council action.

By the time the Electric Department needs, or has the opportunity, to commit to additional resources, the Combustion Turbine bonds will be retired, or nearly so. It is the intent of Grand Island to continue financing major capital improvements without a rate increase.

Future Supply Side Options

Demand and Energy Needs: The proposed combustion turbine addition provides generating resources to satisfy electric demand planning until about 2016. See Figure 9. Beginning in 2012, the increasing use of natural gas will begin to erode the economic efficiency of the Electric Department. However, by 2012 some of the fuel supply questions should be resolved. Not having overspent on the combustion turbine addition, Grand Island will have a great deal of flexibility in selecting a future power source, while maintaining competitive electric rates.

Burdick Station Steam Units: Even though it is an uneconomical energy source, Burdick Station remains an important resource, and is needed for power plant maintenance scheduling. Platte Generating Station is removed from service for one week each spring and fall. Six week preventative maintenance outages occur at three and five year intervals. With 93 MW of capacity, Burdick Station can nearly replace the 100 MW capacity that is unavailable during a PGS outage.

MAPP requires a Planning Reserve of 15% of a utility's peak load. To be accredited, the generation must be tested at rated load for four hours annually. Burdick Station Units #1 & #2 are well suited for the limited use required to meet Planning Reserve.

The 54 MW, Burdick Unit #3 was placed in service during 1972. Shortly thereafter, natural gas was curtailed, followed by the construction of Platte Generating Station. Chronologically it is approaching 30 years old, but it has had only 10 years of actual use. Burdick Unit #3 will continue to be operated, as required, to supply the summer peak load, cover maintenance outages of other units, and provide system capacity.

The Burdick Station steam units remain an important component of the Electric Department's resources. However, more efficient gas-fired generation can be obtained, in the future, by converting the proposed combustion turbines to combined cycle operation.

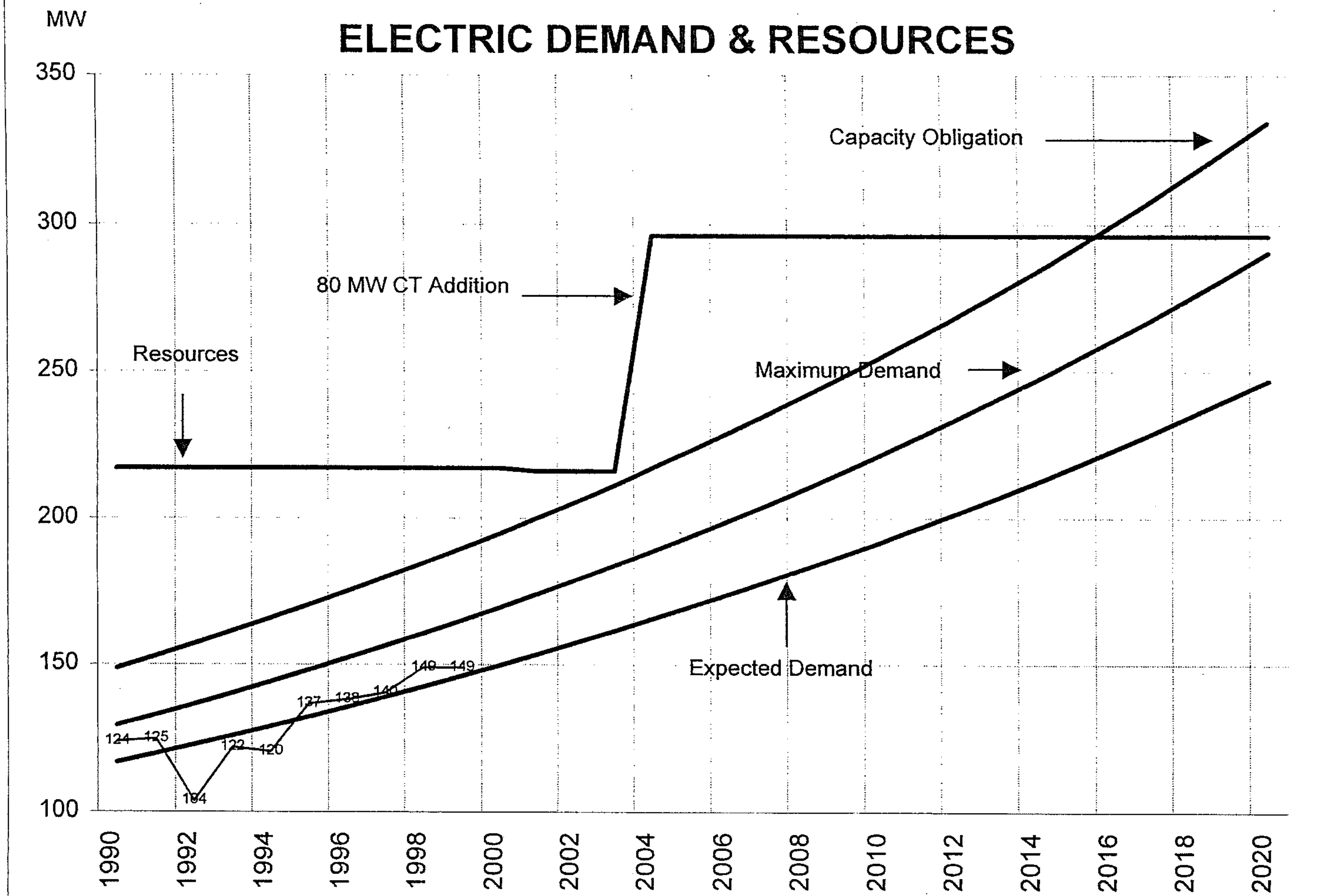
Combined Cycle Combustion Turbine: If the United States increases reliance on natural gas for electrical generation, the proposed combustion turbines are designed for conversion to combined cycle operation through a heat recovery steam generator (HRSG). This modification would provide added capacity in the 2012 time frame, resulting in a highly efficient gas fired resource.

Since peaking capacity is the type of generation that will presently minimize natural gas consumption, combined cycle generation is not being installed as part of the initial construction.

Pulverized Coal: If coal regains favor as a fossil fuel and the price disparity with natural gas remains, construction of coal-fired generation should resume. If Iatan 2, or a similar unit, is revived, Grand Island could be a participant.

The Platte Generating Station site has sufficient space and infrastructure for another coal-fired power plant.

Purchased Power: In 2008, Grand Island's load will be growing at about 5 MW per year, but no capacity will be needed until 2016. A low cost energy source would eliminate the necessity for operating Burdick Station. This energy could be received at a high capacity factor, making efficient use of a seller's surplus



ELECTRIC DEMAND & RESOURCES
MW
350
300
250
200
150
100
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
Capacity Obligation
80 MW CT Addition
Resources
Maximum Demand
Expected Demand
124
125
104
122
120
137
138
140
149
149

Figure 9

generation. Grand Island will be in an excellent position to purchase short-term energy, against the capacity of Burdick Station.

Distributed Generation

The Electric Department routinely examines energy and demand trends, searching for changes in usage patterns, such as electric heating, that will impact system planning. Distributed generation has the potential to benefit both the utility and the consumer.

Electricity is an ever more essential component to modern life. Factories, offices, and homes do not run without electricity. However, electric systems were not designed to provide uninterruptible power. Considering the exposure of transmission and distribution circuits, it is unrealistic to expect 24/7 delivery.

To avoid the inconvenience resulting from the loss of electricity, some customers are exploring their own generation resources. The spike in small generator sales, created by Y2K concerns, supports this. The technology is available to provide customer level distributed generation. Mass production and marketing would make it affordable.

Small internal combustion generators cost far less per kW than do utility installed combustion turbines. Small generators installed at the load and used for peaking could increase the efficiency of the electric distribution system. Initially there will be concern with safety and fuel storage. Electric meters could conceivably include intelligence to perform protective relaying functions.

Internet technology and time-of-use metering will make real-time metering a reality. With customer level distributed generation, customers will have a meaningful method of responding to price signals provided by the utility.

Although the above paragraphs mentioned internal combustion engines, renewable resources could also contribute to distributed generation. In Nebraska, roof top photovoltaic capability closely matches the home air conditioning demand. In such an installation, response to summer sunshine would be automatic. There would be no need for real-time price signals.

If customer owned resources develop, the sharp summer demand peak will diminish. The electric utility would be responsible for furnishing, low cost, base load resources. The customer will assume the responsibility for reliability and peak shaving. If this scenario plays out, the combustion turbine addition could be converted to combined cycle operation, making the proposed expansion the best option for continued service beyond 2012.

Conclusion and Implementation

This recension of the 1996 Integrated Resource Plan determined that additional generating capacity remains needed by 2004. The indefinite and untimely 1999 postponement of Iatan 2 reduced the number of remaining alternatives. The 1997 Kyoto Protocol and rapidly increasing natural gas prices provided other causes for concern.

The Electric Department can minimize natural gas consumption and optimize utilization of Platte Generating Station through the installation of 80 MW simple cycle combustion turbine capacity. Two, nominally rated, 40 MW combustion turbines will be installed to minimize NO_x emissions, improve operating efficiencies, and increase reliability.

The combustion turbines can be operational by 2004. Natural gas consumption will be tolerable through 2012. By 2012, the Kyoto Protocol may be relevant and the fuel situation will have changed. Although demand requirements are satisfied through 2016, Grand Island must reconsider energy resources before that date.

The combustion turbine addition is low cost generation, the Electric Department can finance the bond issue under the current rate structure. The rate structure should continue to provide ample revenue for continued generation optimization beyond 2012.

APPENDIX “B”

FUEL ADJUSTMENT SUMMARY FOR 2006

January 19, 2007

ENERGY	TOTAL COST	AVERAGE COST	SOURCE
		GENERATION	
-82.585 MWh	$315,143.71	$0.00 / MWh	BURDICK STATION -- STEAM TURBINES
669,285.836 MWh	$8,387,309.13	$12.53 / MWh	PLATTE GEN. STATION
11,455.790 MWh	$1,316,232.59	$114.90 / MWh	BURDICK STATION -- COMBUSTION TURBINES
680,659.041 MWh	$10,018,685.43	$14.72 / MWh	TOTAL GENERATION
		TRANSMISSION EXPENSE	
n/a	$142,500.00		WAPA FIRM
n/a	$23,504.28		WIND GENERATION TRANSMISSION
n/a	$250,877.64		MAPP Schedule F
76.200 MWh	$35,094.52		ENERGY IMBALANCE, IMPORT & Transmission
		RECEIPTS	
33,367.000 MWh	$616,013.43	$22.73 / MWh	WAPA FIRM
42,571.000 MWh	$2,219,157.20	$52.13 / MWh	NPPD TYPE EA0
.000 MWh	$0.00	$0.00 / MWh	NPPD EMERGENCY
3,892.784 MWh	$119,097.53	$36.63 / MWh	WIND GENERATION
.000 MWh	$0.00	$0.00 / MWh	
	n.c.		INADVERTENT PAYBACK
79,830.784 MWh	$2,954,268.16	$37.01 / MWh	NET SCHEDULED RECEIPT
			INADVERTENT
		DELIVERIES	
65,863.000 MWh	$2,218,722.50	$33.69 / MWh	NPPD TYPE EA0
.000 MWh	$0.00	$0.00 / MWh	NPPD OPERATIONAL CONTROL
110.000 MWh	$4,766.20	$43.33 / MWh	MAPP EMERGENCY
			INADVERTENT PAYBACK
65,973.000 MWh	$2,223,488.70	$33.70 / MWh	NET SCHEDULED DELIVERY
			INADVERTENT
13,933.984 MWh	$1,182,755.90	$84.88 / MWh	NET METERED IMPORT
694,593.025 MWh	**$11,201,441.33**	**$16.13 / MWh**	**SYSTEM TOTAL**

FUEL ADJUSTMENT SUMMARY FOR 2005

January 23, 2006

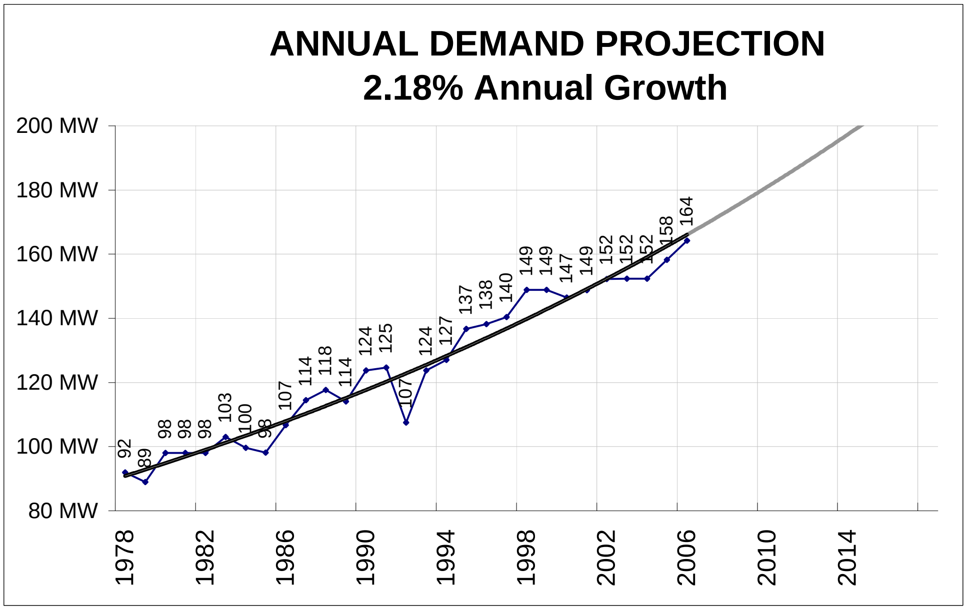
ENERGY	TOTAL COST	AVERAGE COST	SOURCE
		GENERATION	
-396.708 MWh	$206,983.36	$0.00 / MWh	BURDICK STATION -- STEAM TURBINES
659,723.068 MWh	$7,542,524.87	$11.43 / MWh	PLATTE GEN. STATION
8,425.710 MWh	$1,263,810.63	$149.99 / MWh	BURDICK STATION -- COMBUSTION TURBINES
667,752.070 MWh	$9,013,318.86	$13.50 / MWh	TOTAL GENERATION
		TRANSMISSION EXPENSE	
n/a	$142,500.00		WAPA FIRM
n/a	$4,589.97		WIND GENERATION TRANSMISSION
n/a	$265,996.22		MAPP Schedule F
116.600 MWh	$32,542.90		ENERGY IMBALANCE, IMPORT & Transmission
		RECEIPTS	
33,428.000 MWh	$549,017.07	$20.69 / MWh	WAPA FIRM
48,432.000 MWh	$3,298,502.77	$68.11 / MWh	NPPD TYPE EA0
18.000 MWh	$424.62	$23.59 / MWh	NPPD EMERGENCY
1,039.132 MWh	$12,638.20	$16.58 / MWh	WIND GENERATION
.000 MWh	$0.00	$0.00 / MWh	
	n.c.		INADVERTENT PAYBACK
82,917.132 MWh	$3,860,582.66	$46.56 / MWh	NET SCHEDULED RECEIPT
			INADVERTENT
		DELIVERIES	
53,626.000 MWh	$1,709,903.50	$31.89 / MWh	NPPD TYPE EA0
.000 MWh	$0.00	$0.00 / MWh	NPPD OPERATIONAL CONTROL
153.000 MWh	$7,840.20	$51.24 / MWh	MAPP EMERGENCY
			INADVERTENT PAYBACK
53,779.000 MWh	$1,717,743.70	$31.94 / MWh	NET SCHEDULED DELIVERY
			INADVERTENT
29,254.732 MWh	$2,588,468.05	$88.48 / MWh	NET METERED IMPORT
697,006.802 MWh	**$11,601,786.91**	**$16.65 / MWh**	**SYSTEM TOTAL**

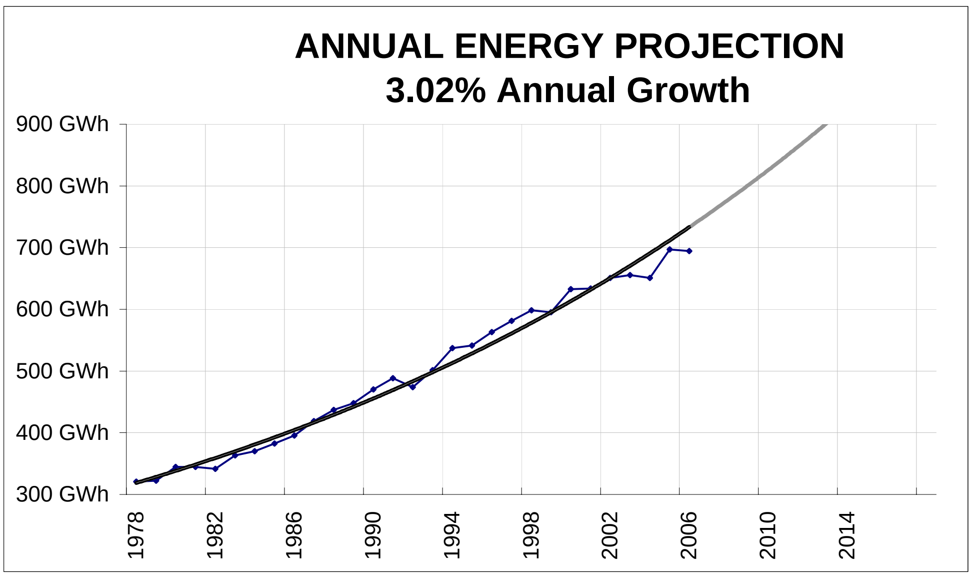
APPENDIX “C”

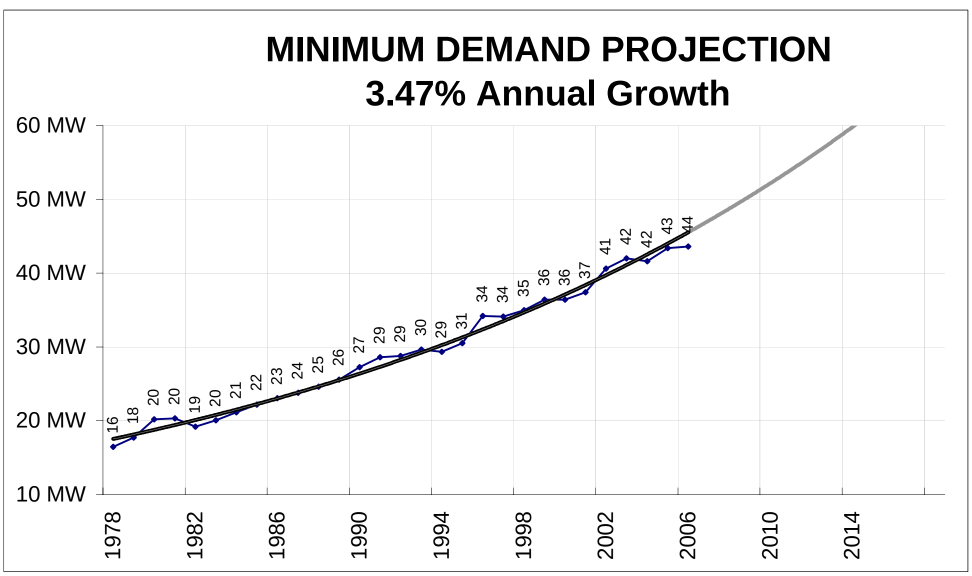
MONTHLY DEMAND & ENERGY SUMMARY

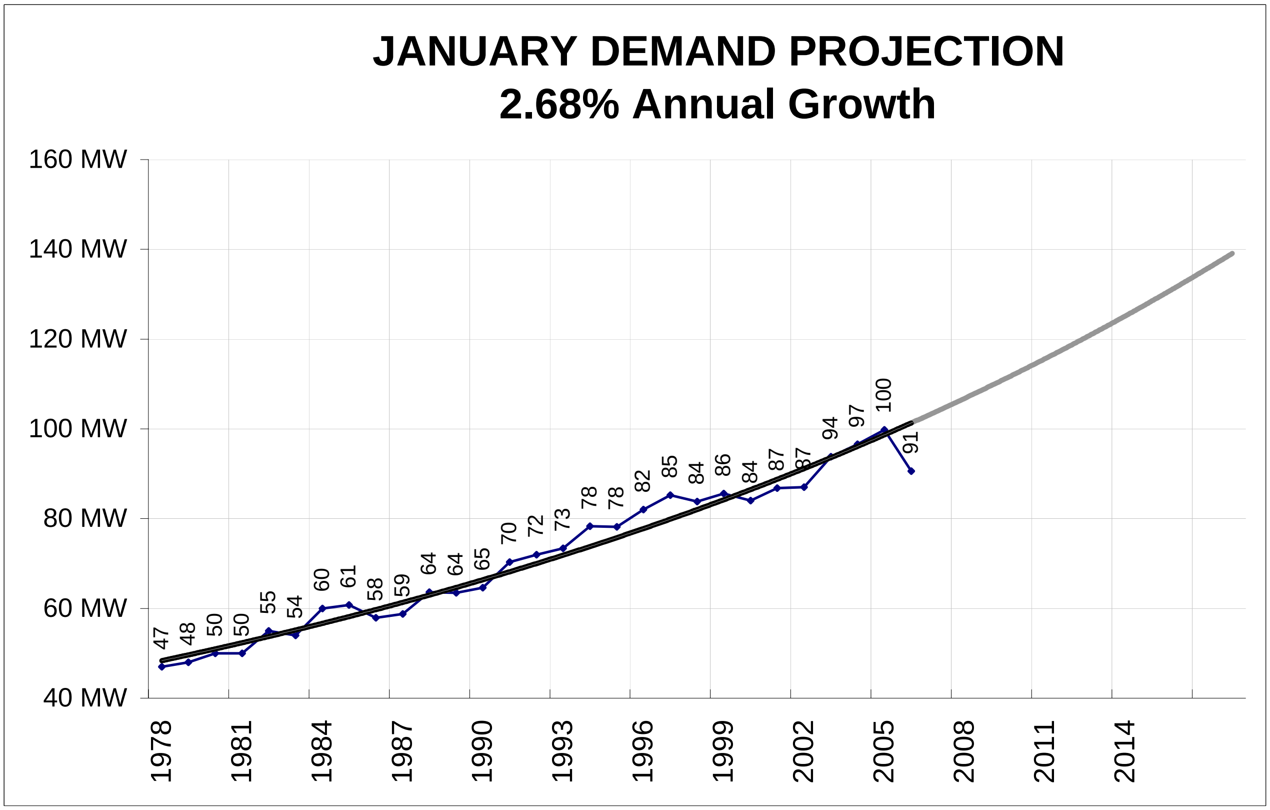
13-Mar-07

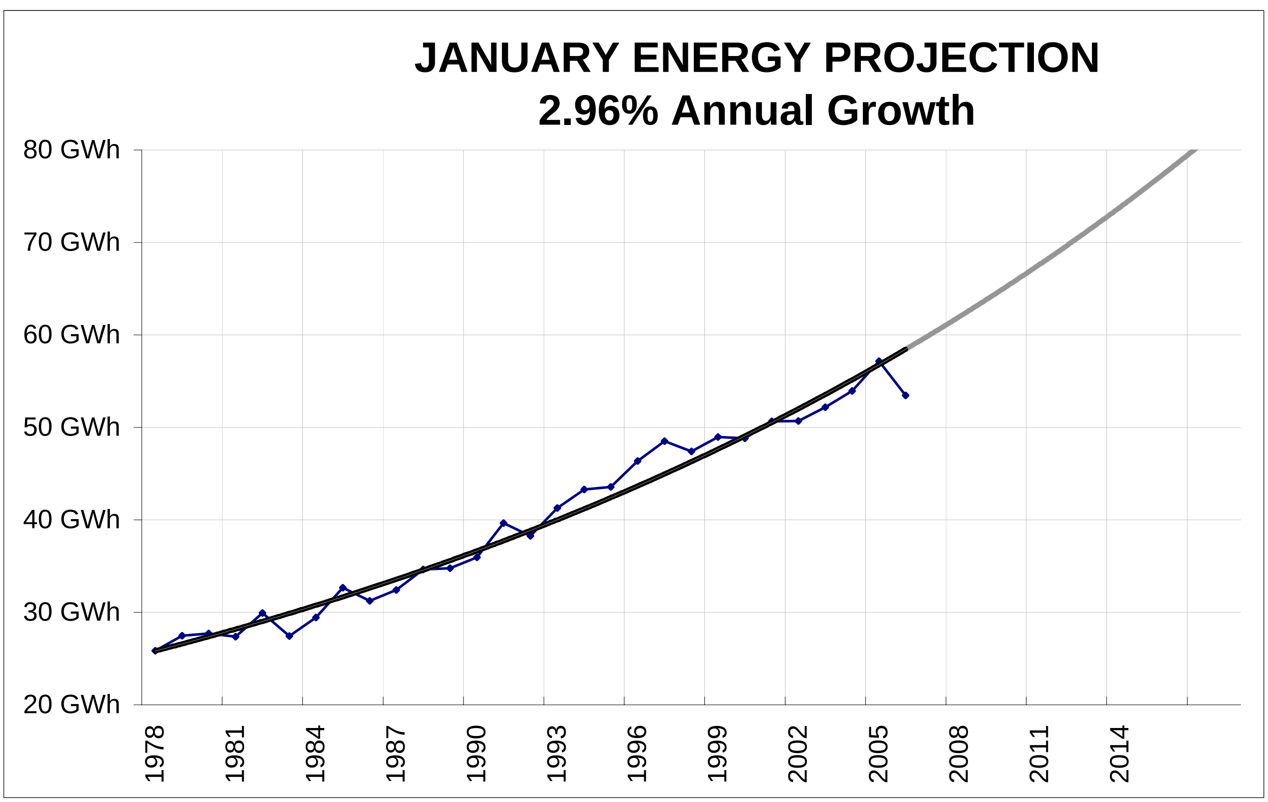
YEAR	1998	1999	2000	2001	2002	2003	2004	2005	2006
JAN	83.8 MW	85.6 MW	84.0 MW	86.8 MW	87.0 MW	93.8 MW	96.6 MW	99.8 MW	90.6 MW
FEB	79.0 MW	83.2 MW	82.6 MW	87.8 MW	88.4 MW	89.2 MW	92.2 MW	94.0 MW	101.8 MW
MAR	82.4 MW	80.8 MW	80.0 MW	83.5 MW	88.8 MW	92.8 MW	87.4 MW	90.4 MW	91.0 MW
APR	77.2 MW	78.0 MW	80.7 MW	91.4 MW	100.4 MW	98.3 MW	99.0 MW	89.4 MW	96.8 MW
MAY	117.1 MW	91.0 MW	118.4 MW	119.4 MW	125.7 MW	105.3 MW	109.4 MW	125.8 MW	123.6 MW
JUN	130.7 MW	125.1 MW	131.7 MW	136.8 MW	140.1 MW	138.4 MW	133.4 MW	144.6 MW	144.2 MW
JUL	148.9 MW	148.9 MW	145.2 MW	148.4 MW	152.3 MW	152.4 MW	152.4 MW	158.2 MW	164.2 MW
AUG	138.9 MW	131.7 MW	146.5 MW	148.8 MW	142.9 MW	150.7 MW	145.8 MW	157.6 MW	159.0 MW
SEP	130.7 MW	131.1 MW	124.6 MW	132.2 MW	135.2 MW	121.8 MW	131.4 MW	135.2 MW	108.4 MW
OCT	82.6 MW	81.6 MW	91.1 MW	95.8 MW	103.5 MW	99.2 MW	89.2 MW	127.8 MW	112.0 MW
NOV	79.2 MW	79.6 MW	84.4 MW	87.4 MW	87.9 MW	87.0 MW	95.8 MW	99.8 MW	102.6 MW
DEC	87.0 MW	86.4 MW	93.8 MW	88.6 MW	91.0 MW	94.8 MW	99.2 MW	106.4 MW	100.0 MW
SUM. MAX.	148.9 MW	148.9 MW	146.5 MW	148.8 MW	152.3 MW	152.4 MW	152.4 MW	158.2 MW	164.2 MW
WIN. MAX.	87.0 MW	86.4 MW	93.8 MW	100.4 MW	98.3 MW	99.0 MW	99.2 MW	106.4 MW	102.6 MW
JAN	47,412 MWh	48,951 MWh	48,837 MWh	50,646 MWh	50,689 MWh	52,190 MWh	53,931 MWh	57,176 MWh	53,447 MWh
FEB	41,749 MWh	42,393 MWh	45,049 MWh	46,242 MWh	45,314 MWh	46,888 MWh	49,764 MWh	48,203 MWh	51,135 MWh
MAR	46,923 MWh	45,874 MWh	46,250 MWh	48,161 MWh	49,645 MWh	49,907 MWh	49,963 MWh	52,496 MWh	54,150 MWh
APR	42,341 MWh	42,965 MWh	43,459 MWh	44,109 MWh	46,644 MWh	47,968 MWh	47,691 MWh	48,937 MWh	48,489 MWh
MAY	47,738 MWh	45,174 MWh	50,793 MWh	50,570 MWh	49,186 MWh	49,796 MWh	52,884 MWh	55,069 MWh	56,630 MWh
JUN	53,135 MWh	53,569 MWh	58,279 MWh	58,814 MWh	64,599 MWh	56,668 MWh	57,708 MWh	65,632 MWh	66,784 MWh
JUL	66,373 MWh	70,123 MWh	66,931 MWh	72,266 MWh	75,713 MWh	75,814 MWh	65,292 MWh	76,314 MWh	77,657 MWh
AUG	63,633 MWh	61,666 MWh	71,761 MWh	69,281 MWh	67,373 MWh	72,814 MWh	63,496 MWh	71,712 MWh	71,163 MWh
SEP	55,319 MWh	49,160 MWh	54,362 MWh	51,020 MWh	54,314 MWh	52,581 MWh	56,377 MWh	60,114 MWh	52,524 MWh
OCT	44,539 MWh	44,657 MWh	47,547 MWh	47,387 MWh	49,274 MWh	50,359 MWh	49,266 MWh	52,738 MWh	53,737 MWh
NOV	42,688 MWh	43,288 MWh	47,245 MWh	45,948 MWh	47,409 MWh	48,159 MWh	49,734 MWh	50,969 MWh	52,799 MWh
DEC	46,827 MWh	47,627 MWh	52,003 MWh	49,462 MWh	50,692 MWh	52,326 MWh	54,843 MWh	57,647 MWh	56,079 MWh
TOTAL	598,676 MWh	595,447 MWh	632,516 MWh	633,906 MWh	650,851 MWh	655,470 MWh	650,950 MWh	697,007 MWh	694,593 MWh
ANNUAL LF	46%	46%	49%	49%	49%	49%	49%	50%	48%

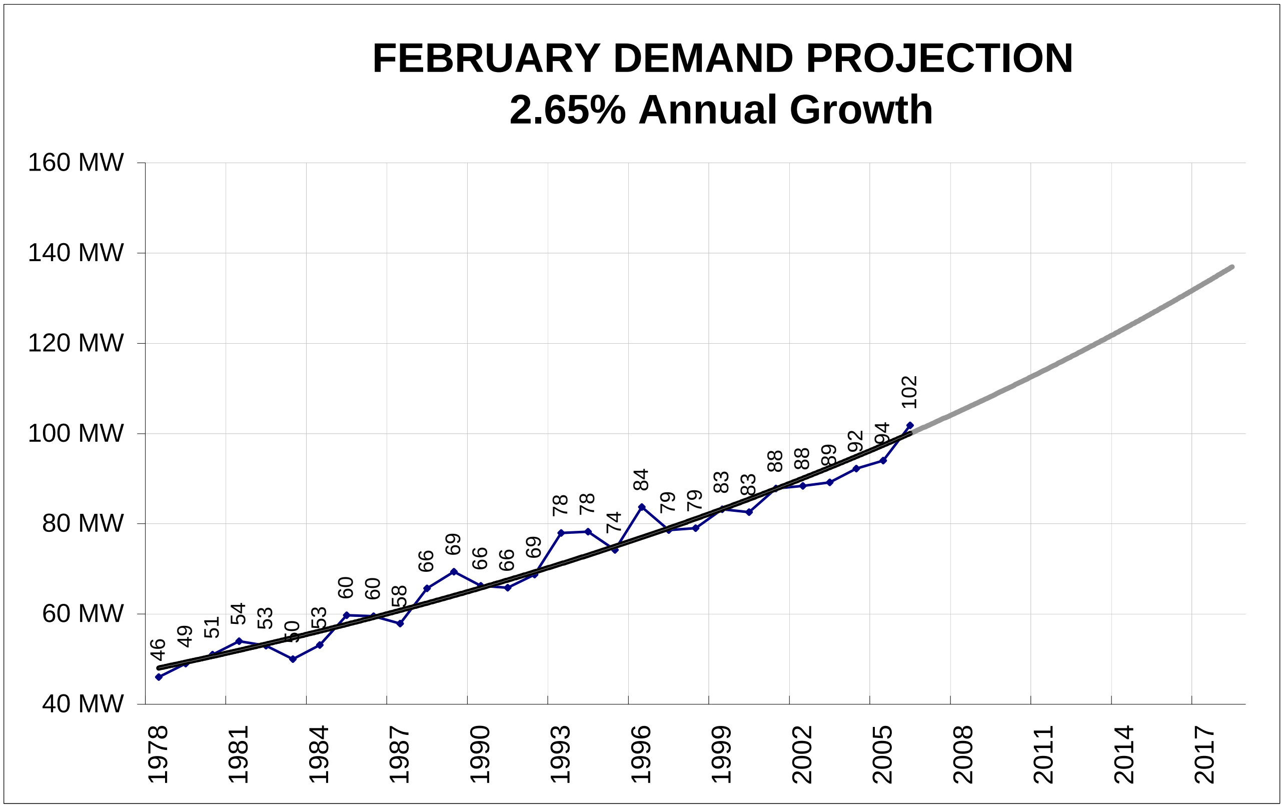

ANNUAL DEMAND PROJECTION
2.18% Annual Growth
200 MW
180 MW
160 MW
140 MW
120 MW
100 MW
80 MW
92
89
98
98
98
103
100
98
107
114
118
114
124
125
107
124
127
137
138
140
149
149
147
149
152
152
152
158
164
1978
1982
1986
1990
1994
1998
2002
2006
2010
2014

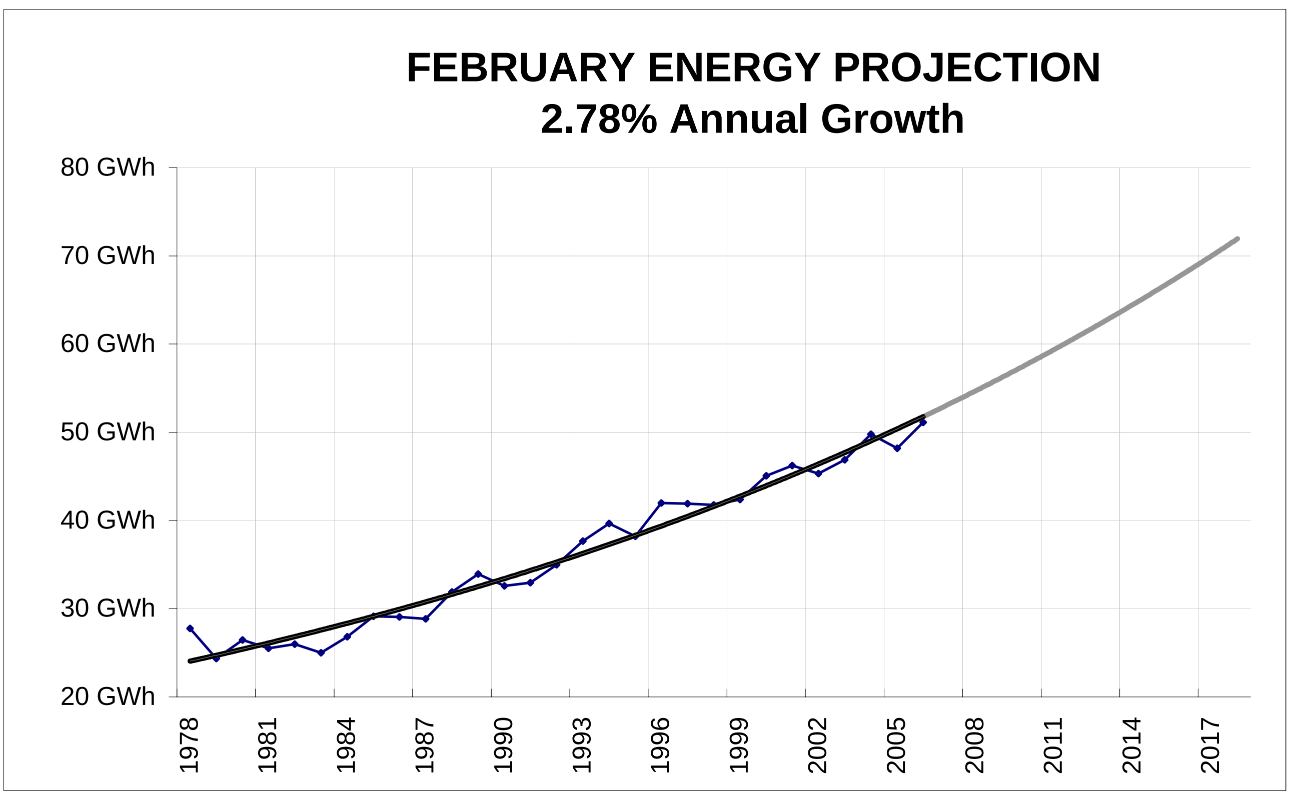

ANNUAL ENERGY PROJECTION
3.02% Annual Growth
900 GWh
800 GWh
700 GWh
600 GWh
500 GWh
400 GWh
300 GWh
1978
1982
1986
1990
1994
1998
2002
2006
2010
2014

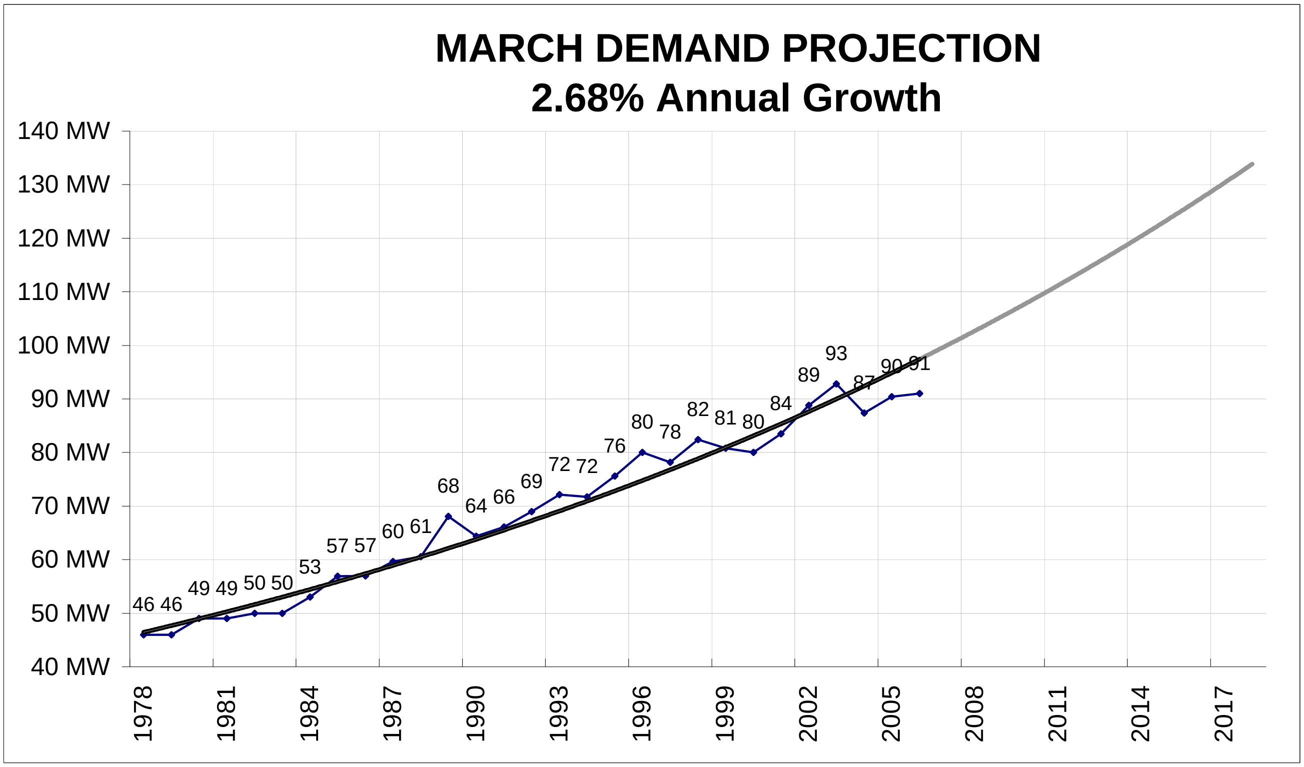

MINIMUM DEMAND PROJECTION
3.47% Annual Growth
60 MW
50 MW
40 MW
30 MW
20 MW
10 MW
16
18
20
20
19
20
21
22
23
24
25
26
27
29
29
30
29
31
34
34
35
36
36
37
41
42
42
43
44
1978
1982
1986
1990
1994
1998
2002
2006
2010
2014

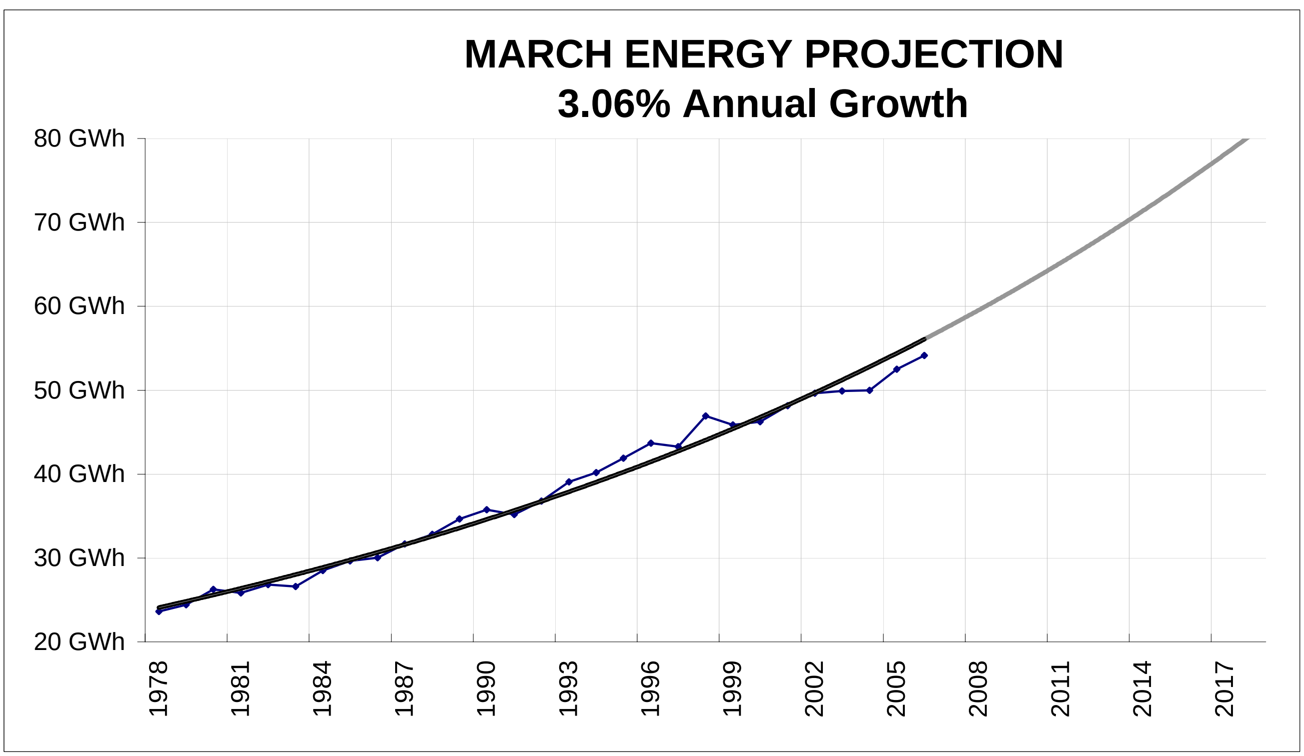

JANUARY DEMAND PROJECTION
2.68% Annual Growth
160 MW
140 MW
120 MW
100 MW
80 MW
60 MW
40 MW
47
48
50
50
55
54
60
61
58
59
64
64
65
70
72
73
78
78
82
85
84
86
84
87
87
94
97
100
91
1978
1981
1984
1987
1990
1993
1996
1999
2002
2005
2008
2011
2014

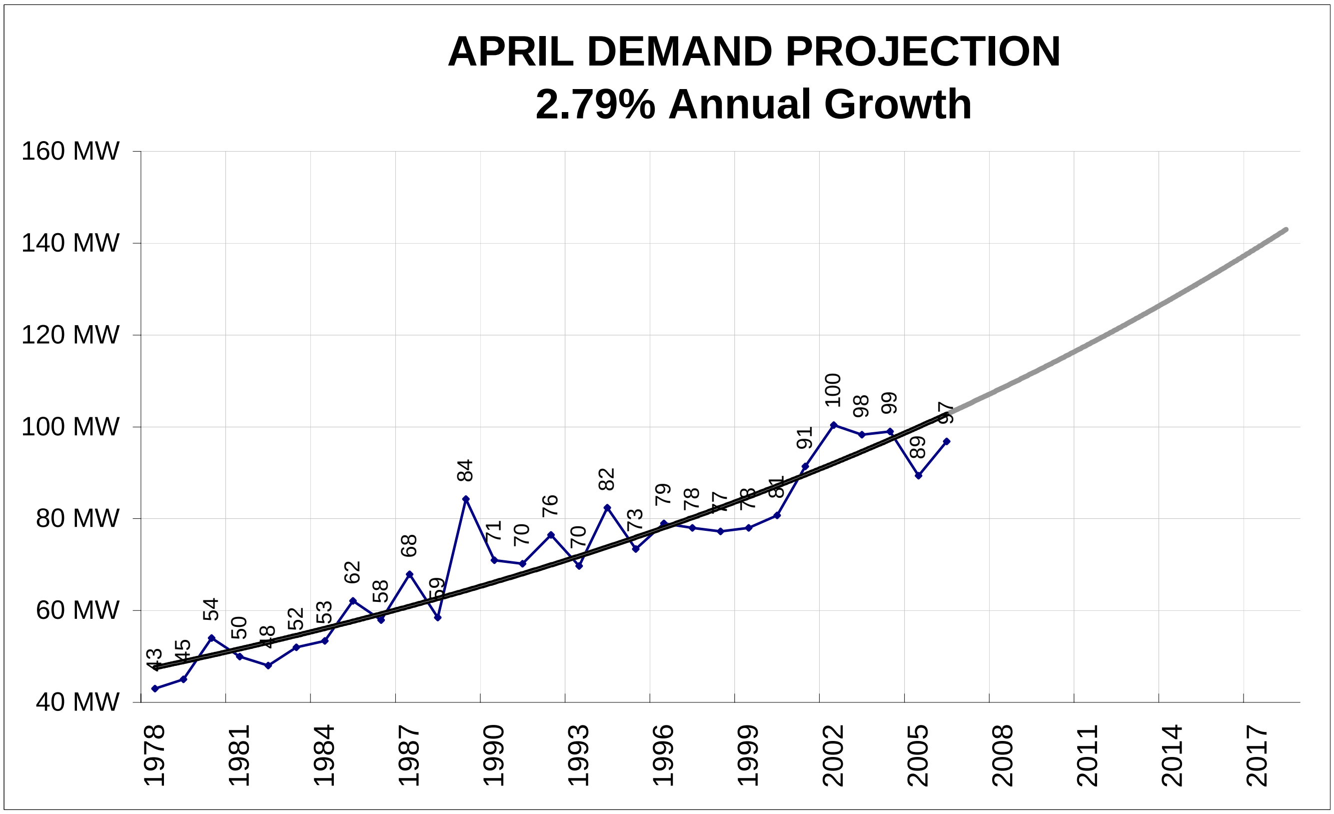

JANUARY ENERGY PROJECTION
2.96% Annual Growth
80 GWh
70 GWh
60 GWh
50 GWh
40 GWh
30 GWh
20 GWh
1978
1981
1984
1987
1990
1993
1996
1999
2002
2005
2008
2011
2014


FEBRUARY DEMAND PROJECTION
2.65% Annual Growth
160 MW
140 MW
120 MW
100 MW
80 MW
60 MW
40 MW
46
49
51
54
53
50
53
60
60
58
66
69
66
66
69
78
78
74
84
79
79
83
83
88
88
89
92
94
102
1978
1981
1984
1987
1990
1993
1996
1999
2002
2005
2008
2011
2014
2017


FEBRUARY ENERGY PROJECTION
2.78% Annual Growth
80 GWh
70 GWh
60 GWh
50 GWh
40 GWh
30 GWh
20 GWh
1978
1981
1984
1987
1990
1993
1996
1999
2002
2005
2008
2011
2014
2017


MARCH DEMAND PROJECTION
2.68% Annual Growth
140 MW
130 MW
120 MW
110 MW
100 MW
90 MW
80 MW
70 MW
60 MW
50 MW
40 MW
46 46 49 49 50 50 53 57 57 60 61 68 64 66 69 72 72 76 80 78 82 81 80 84 89 93 87 90 91
1978
1981
1984
1987
1990
1993
1996
1999
2002
2005
2008
2011
2014
2017


MARCH ENERGY PROJECTION
3.06% Annual Growth
80 GWh
70 GWh
60 GWh
50 GWh
40 GWh
30 GWh
20 GWh
1978
1981
1984
1987
1990
1993
1996
1999
2002
2005
2008
2011
2014
2017



APRIL DEMAND PROJECTION
2.79% Annual Growth
160 MW
140 MW
120 MW
100 MW
80 MW
60 MW
40 MW
43
45
54
50
48
52
53
62
58
68
59
84
71
70
76
70
82
73
79
78
77
78
81
91
100
98
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89
97
1978
1981
1984
1987
1990
1993
1996
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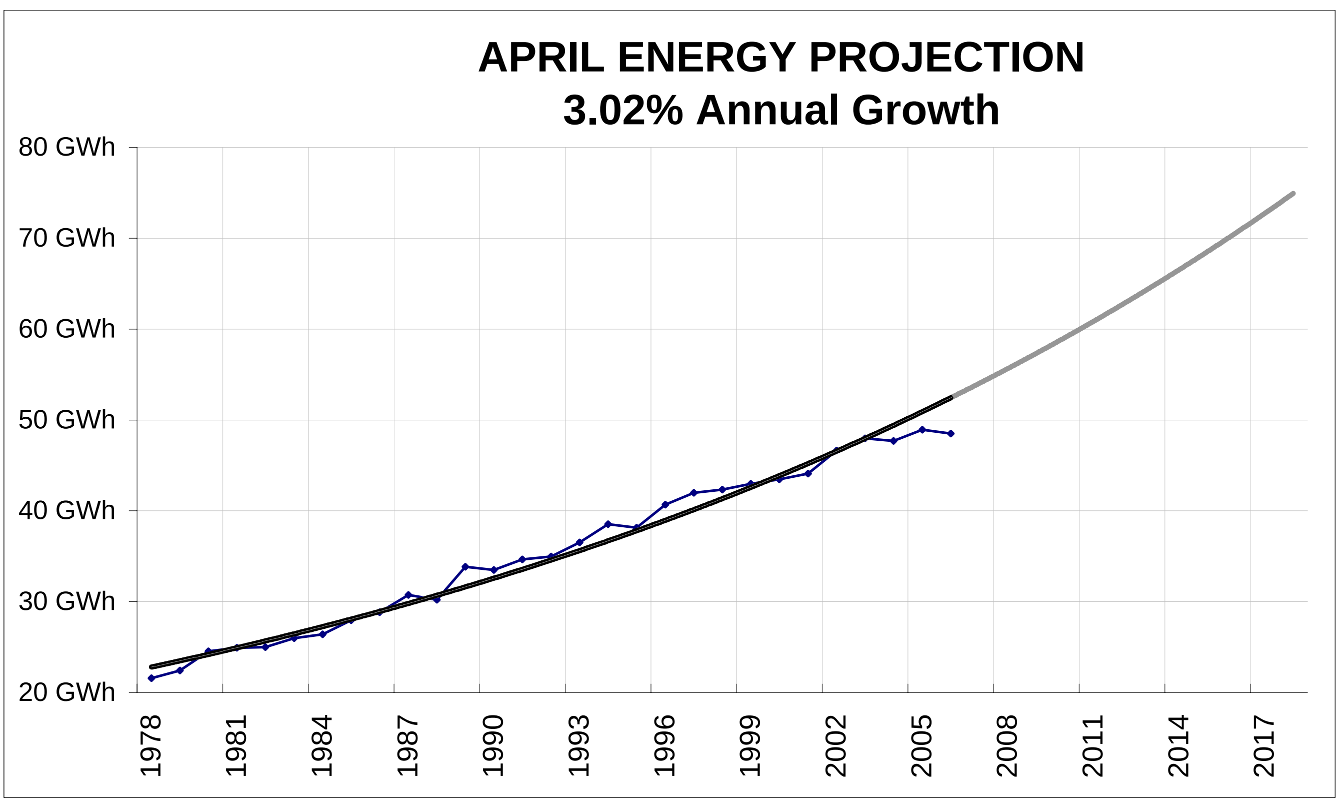
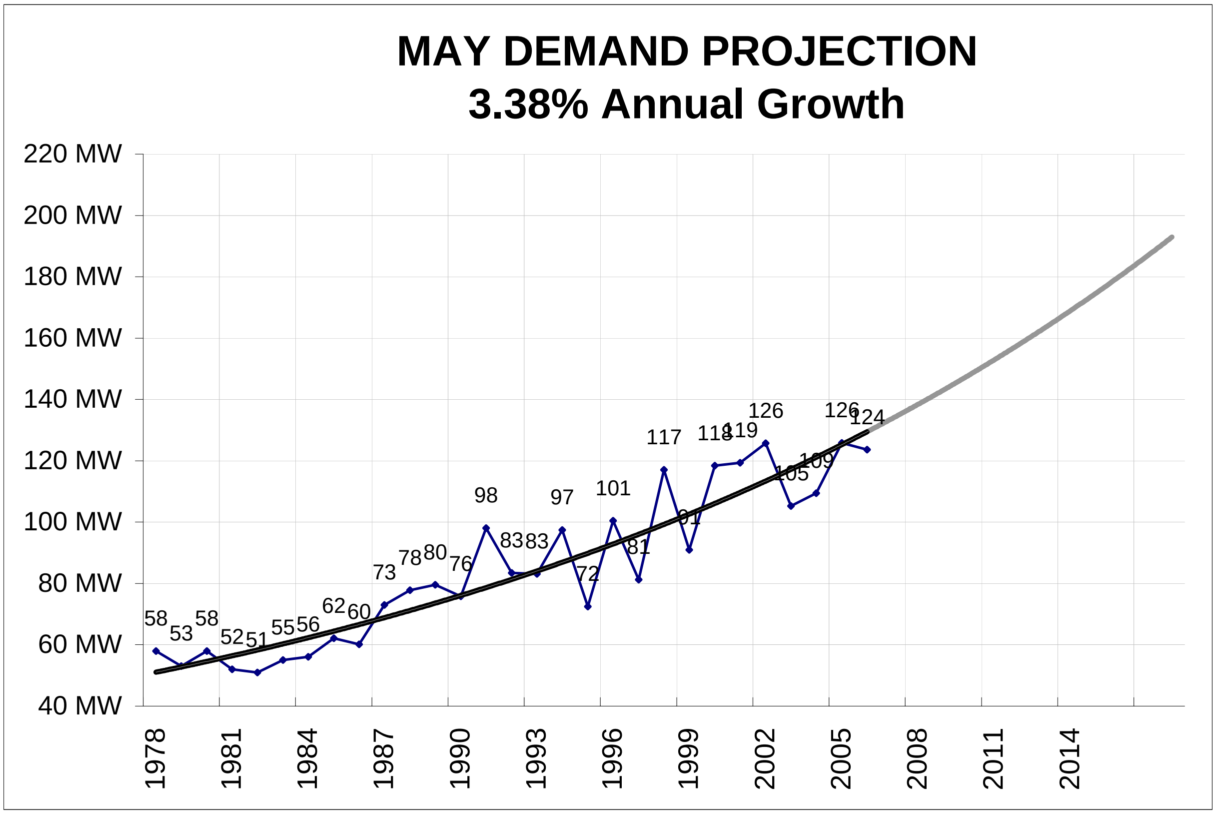
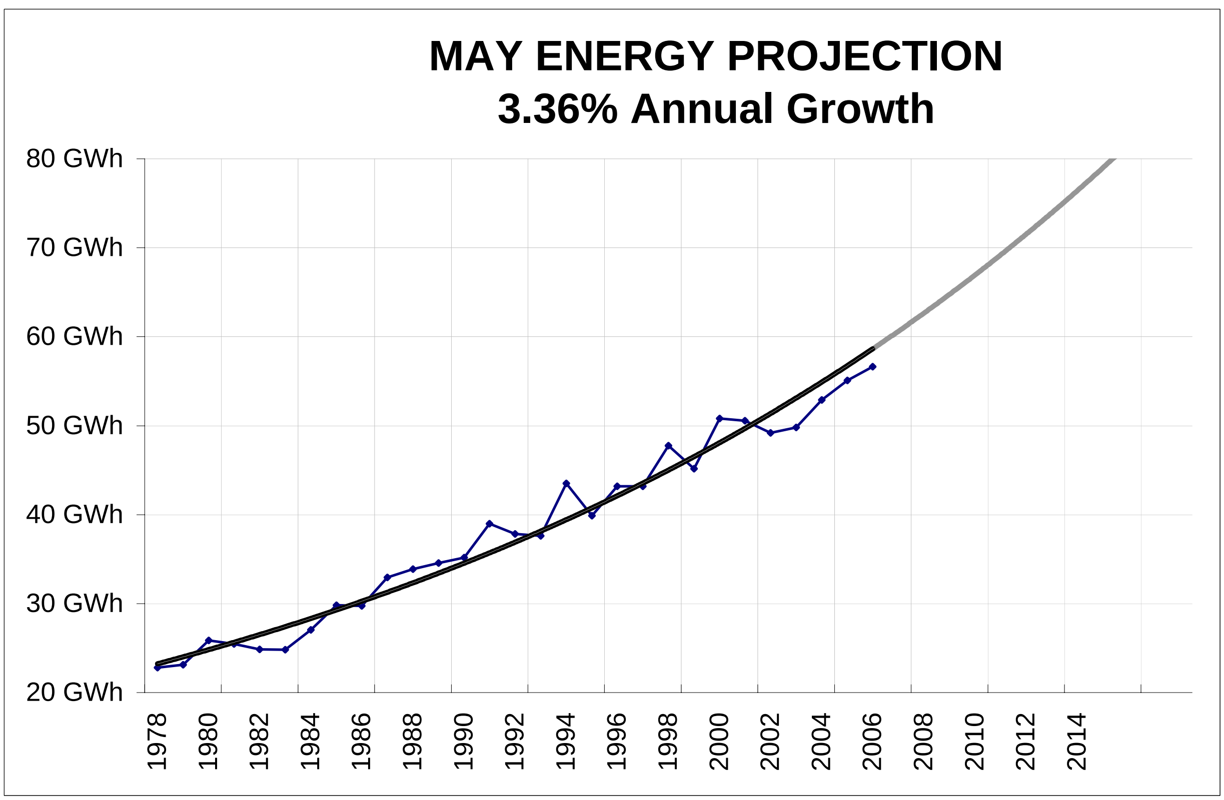
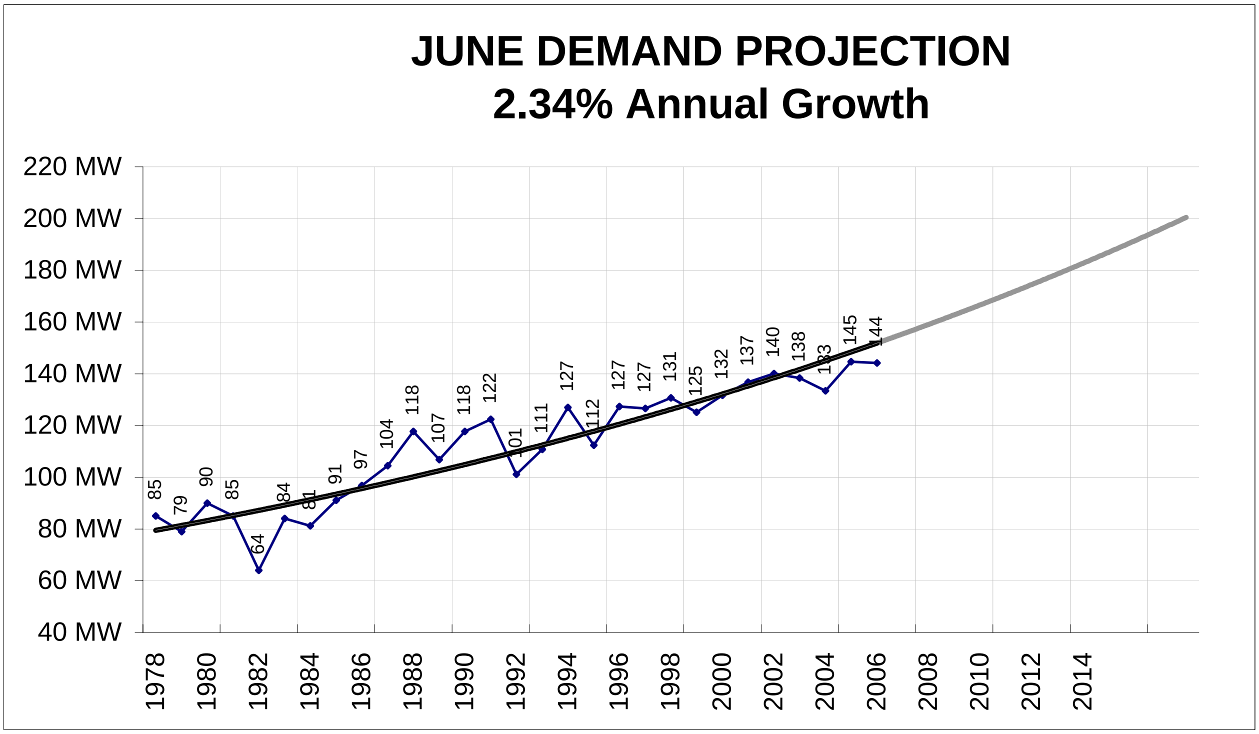
2002
2005
2008
2011
2014
2017

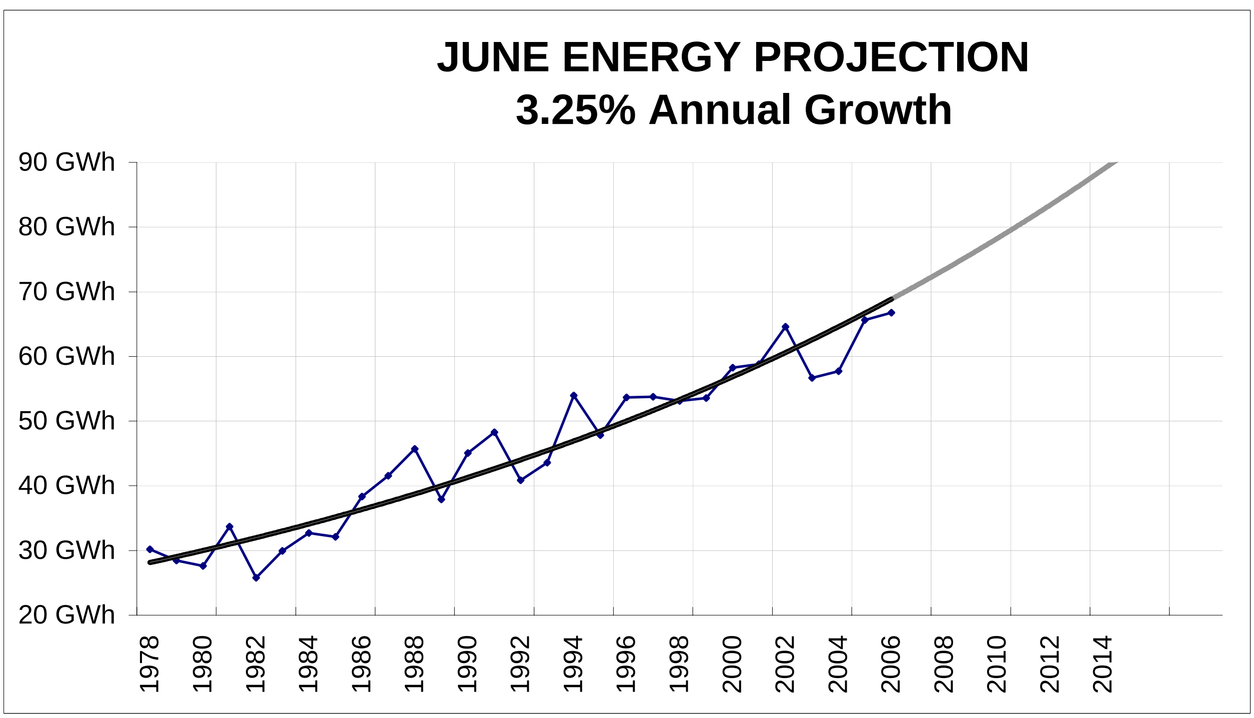


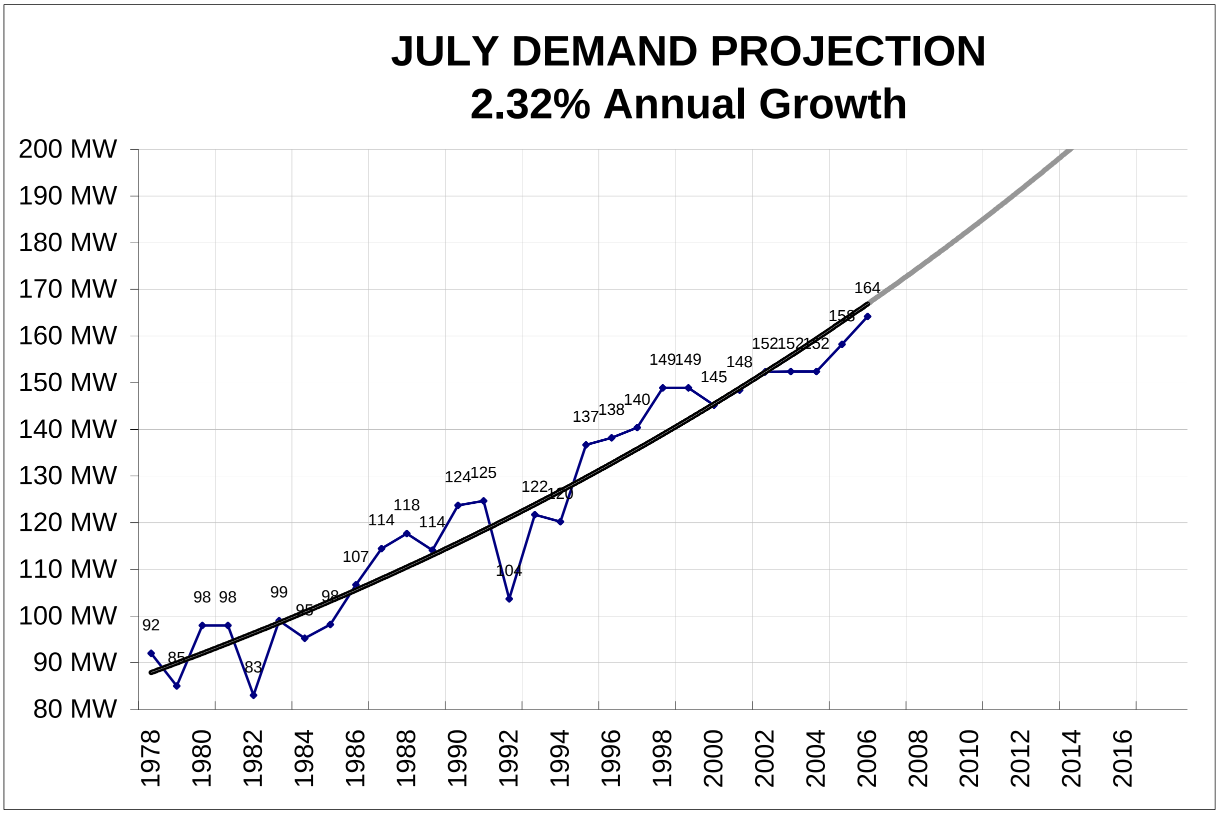
APRIL ENERGY PROJECTION
3.02% Annual Growth
80 GWh
70 GWh
60 GWh
50 GWh
40 GWh
30 GWh
20 GWh
1978
1981
1984
1987
1990
1993
1996
1999
2002
2005
2008
2011
2014
2017

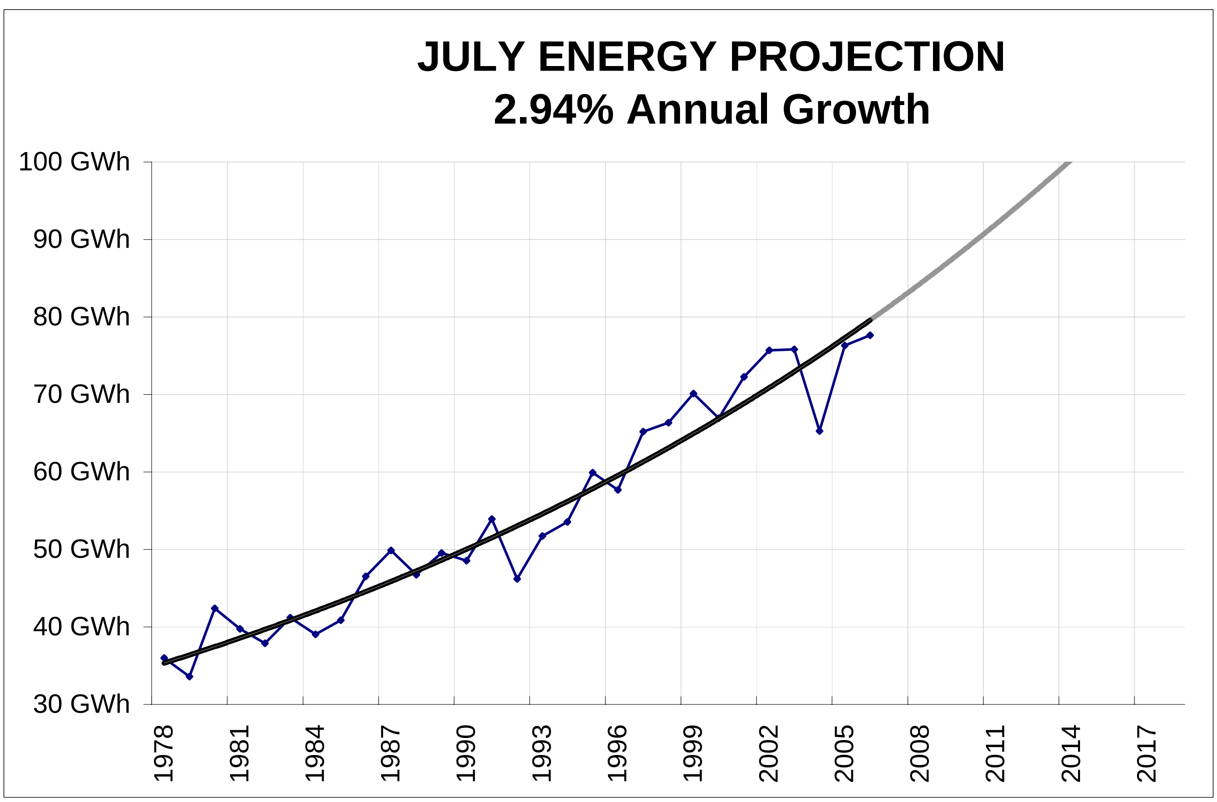

MAY DEMAND PROJECTION
3.38% Annual Growth
220 MW
200 MW
180 MW
160 MW
140 MW
120 MW
100 MW
80 MW
60 MW
40 MW
58
53
58
52
51
55
56
62
60
73
78
80
76
98
83
83
97
72
101
81
117
91
118
119
126
105
109
126
124
1978
1981
1984
1987
1990
1993
1996
1999
2002
2005
2008
2011
2014

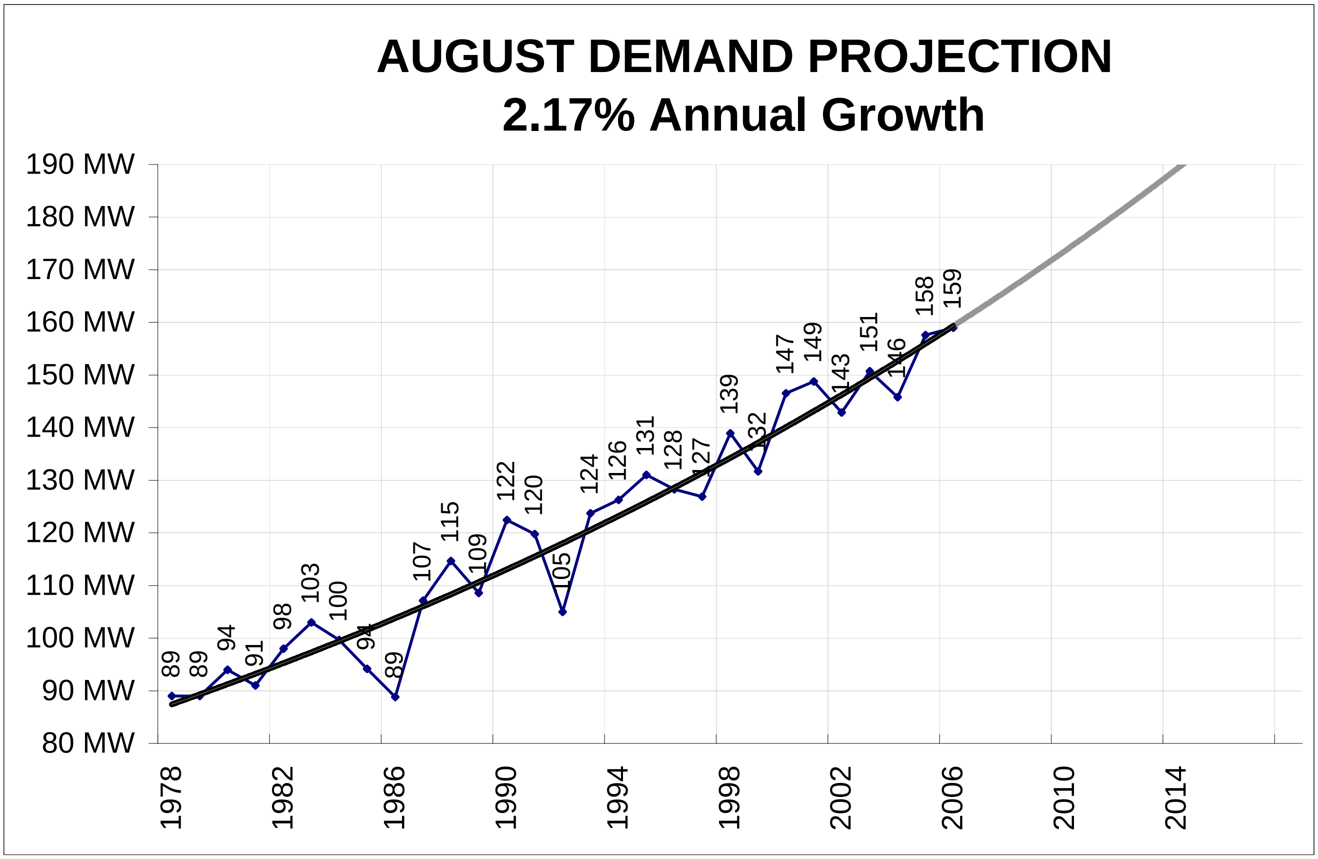

MAY ENERGY PROJECTION
3.36% Annual Growth
80 GWh
70 GWh
60 GWh
50 GWh
40 GWh
30 GWh
20 GWh
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014

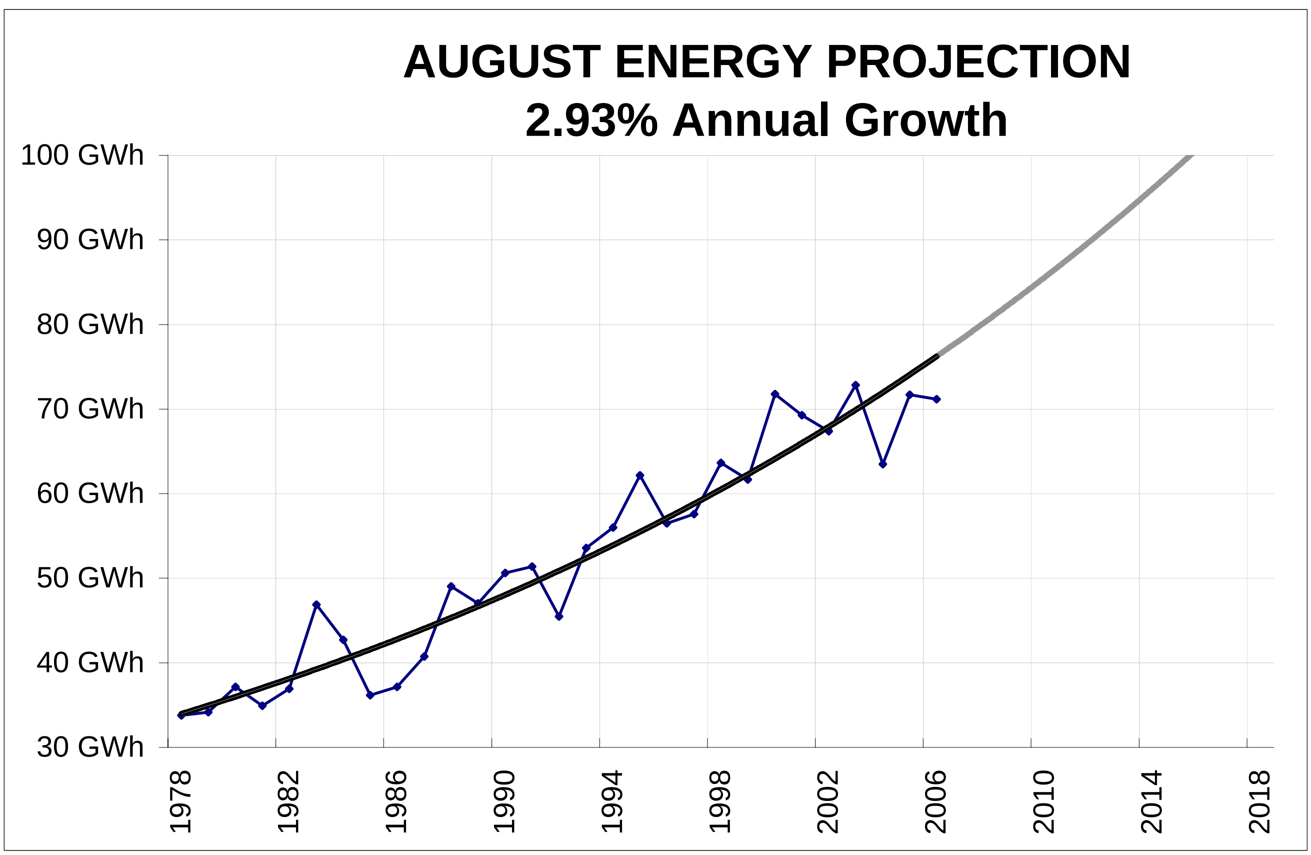

JUNE DEMAND PROJECTION
2.34% Annual Growth
220 MW
200 MW
180 MW
160 MW
140 MW
120 MW
100 MW
80 MW
60 MW
40 MW
85 79 90 85 64 84 81 91 97 104 118 107 118 122 101 111 127 112 127 127 131 125 132 137 140 138 133 145 144
1978 1980 1982 1984 1986 1988 1990 1992 1994 1996 1998 2000 2002 2004 2006 2008 2010 2012 2014

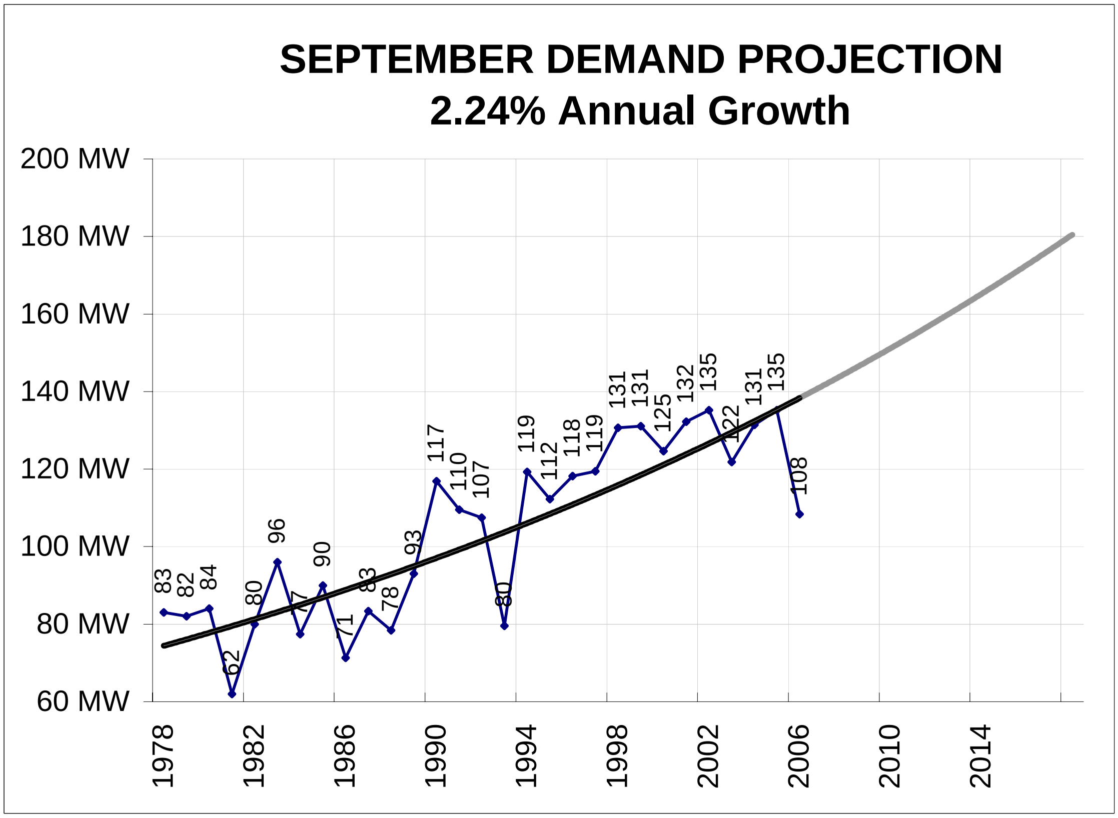

JUNE ENERGY PROJECTION
3.25% Annual Growth
90 GWh
80 GWh
70 GWh
60 GWh
50 GWh
40 GWh
30 GWh
20 GWh
1978 1980 1982 1984 1986 1988 1990 1992 1994 1996 1998 2000 2002 2004 2006 2008 2010 2012 2014


JULY DEMAND PROJECTION
2.32% Annual Growth
200 MW
190 MW
180 MW
170 MW
160 MW
150 MW
140 MW
130 MW
120 MW
110 MW
100 MW
90 MW
80 MW
92
85
98 98
83
99
95
98
107
114
118
114
124 125
104
122
120
137 138 140
149 149
145
148
152 152 152
158
164
1978 1980 1982 1984 1986 1988 1990 1992 1994 1996 1998 2000 2002 2004 2006 2008 2010 2012 2014 2016

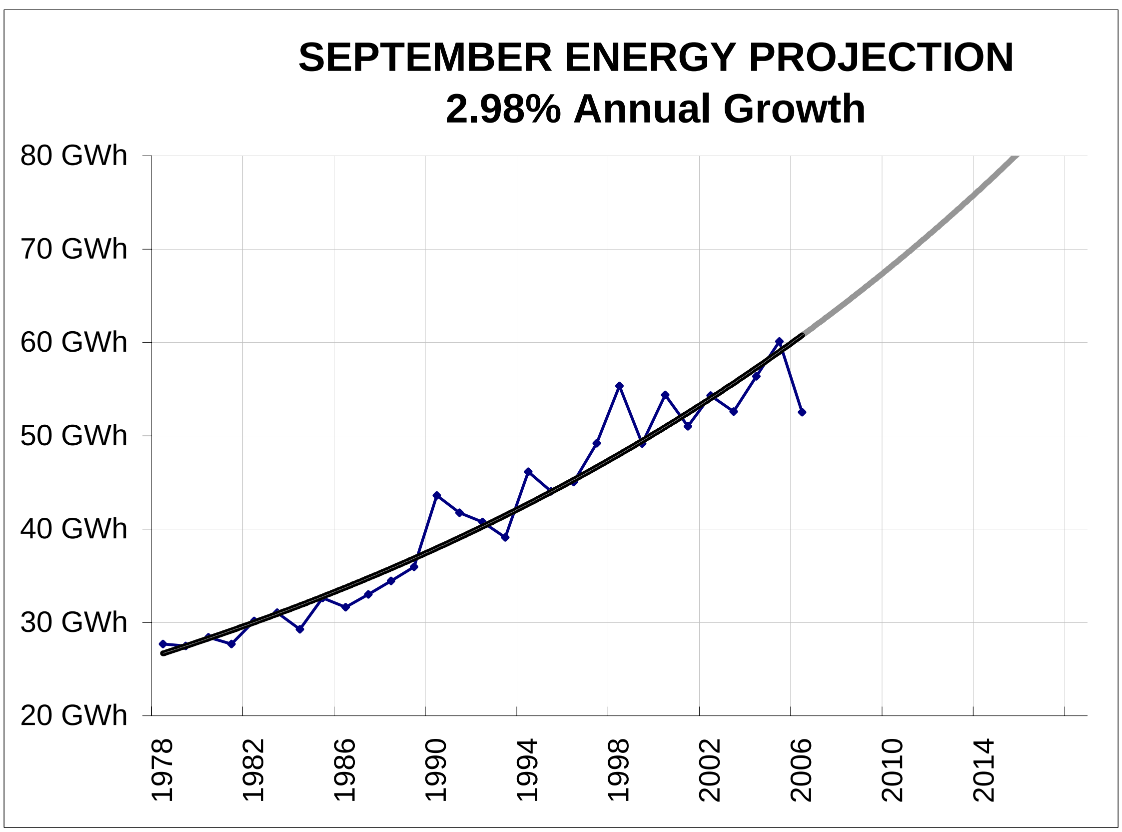

JULY ENERGY PROJECTION
2.94% Annual Growth
100 GWh
90 GWh
80 GWh
70 GWh
60 GWh
50 GWh
40 GWh
30 GWh
1978 1981 1984 1987 1990 1993 1996 1999 2002 2005 2008 2011 2014 2017


AUGUST DEMAND PROJECTION
2.17% Annual Growth
190 MW
180 MW
170 MW
160 MW
150 MW
140 MW
130 MW
120 MW
110 MW
100 MW
90 MW
80 MW
89
89
94
91
98
103
100
94
89
107
115
109
122
120
105
124
126
131
128
127
139
132
147
149
143
151
146
158
159
1978
1982
1986
1990
1994
1998
2002
2006
2010
2014

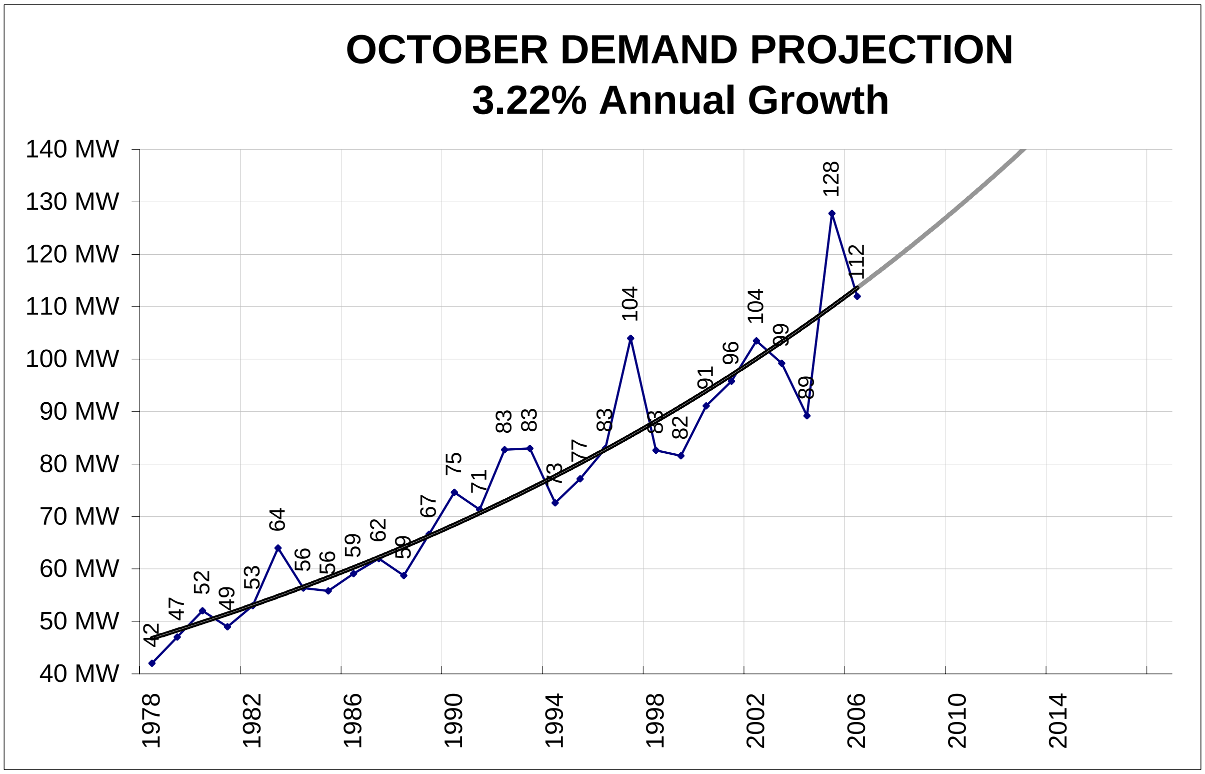

AUGUST ENERGY PROJECTION
2.93% Annual Growth
100 GWh
90 GWh
80 GWh
70 GWh
60 GWh
50 GWh
40 GWh
30 GWh
1978
1982
1986
1990
1994
1998
2002
2006
2010
2014
2018

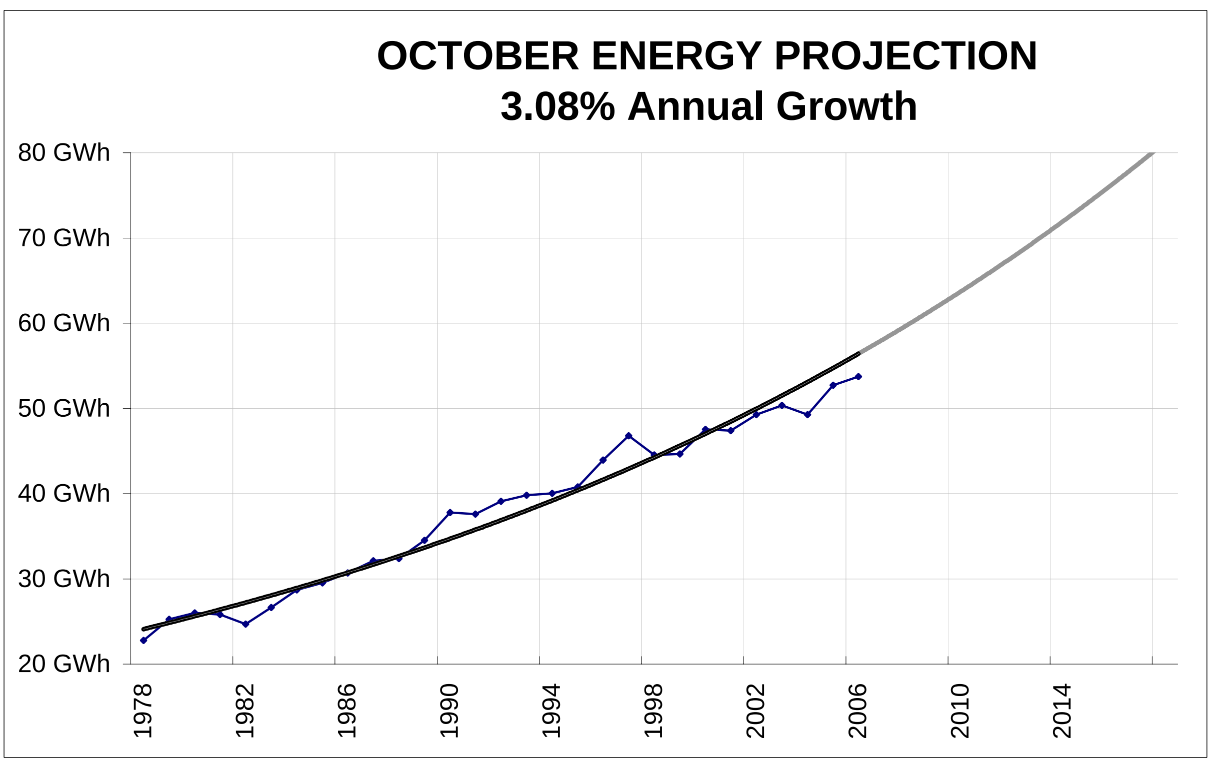


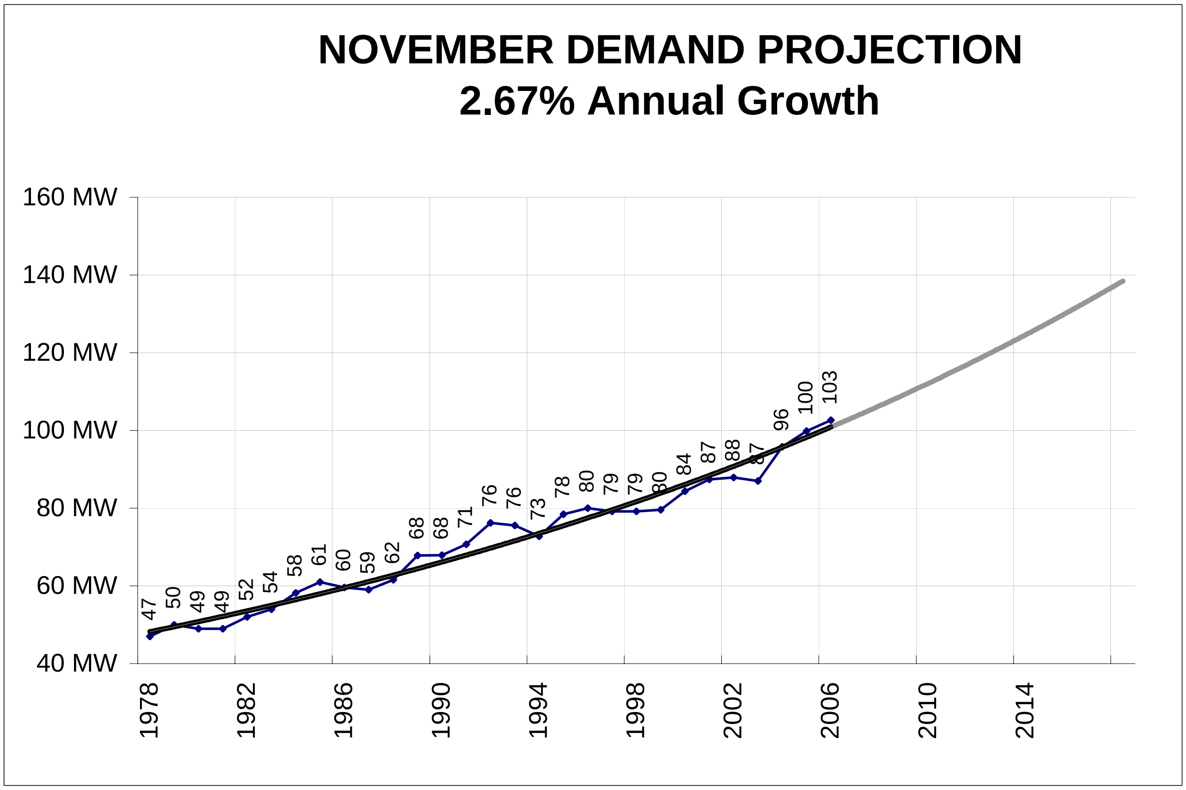
SEPTEMBER DEMAND PROJECTION
2.24% Annual Growth
200 MW
180 MW
160 MW
140 MW
120 MW
100 MW
80 MW
60 MW
83
82
84
62
80
96
77
90
71
83
78
93
117
110
107
80
119
112
118
119
131
131
125
132
135
122
131
135
108
1978
1982
1986
1990
1994
1998
2002
2006
2010
2014

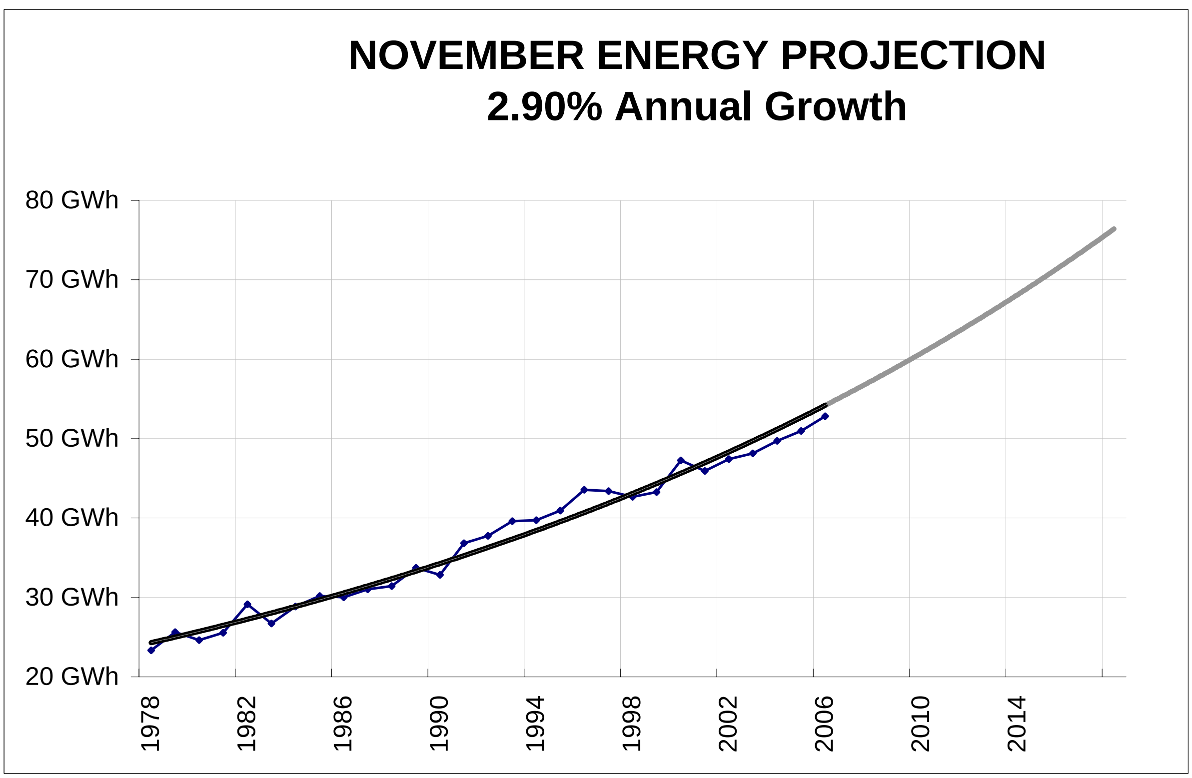


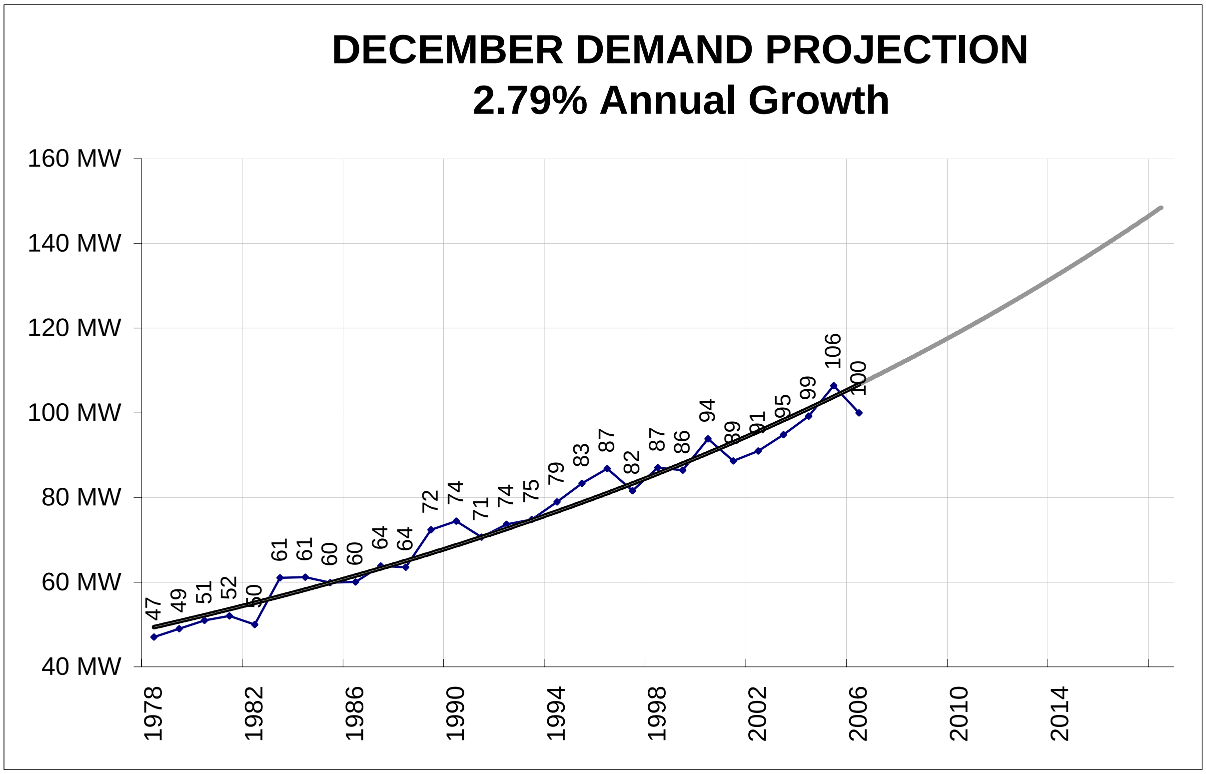
SEPTEMBER ENERGY PROJECTION
2.98% Annual Growth
80 GWh
70 GWh
60 GWh
50 GWh
40 GWh
30 GWh
20 GWh
1978
1982
1986
1990
1994
1998
2002
2006
2010
2014


OCTOBER DEMAND PROJECTION
3.22% Annual Growth
140 MW
130 MW
120 MW
110 MW
100 MW
90 MW
80 MW
70 MW
60 MW
50 MW
40 MW
42
47
52
49
53
64
56
56
59
62
59
67
75
71
83
83
73
77
83
104
83
82
91
96
104
99
89
128
112
1978
1982
1986
1990
1994
1998
2002
2006
2010
2014


OCTOBER ENERGY PROJECTION
3.08% Annual Growth
80 GWh
70 GWh
60 GWh
50 GWh
40 GWh
30 GWh
20 GWh
1978
1982
1986
1990
1994
1998
2002
2006
2010
2014


NOVEMBER DEMAND PROJECTION
2.67% Annual Growth
160 MW
140 MW
120 MW
100 MW
80 MW
60 MW
40 MW
47
50
49
49
52
54
58
61
60
59
62
68
68
71
76
76
73
78
80
79
79
80
84
87
88
87
96
100
103
1978
1982
1986
1990
1994
1998
2002
2006
2010
2014


NOVEMBER ENERGY PROJECTION
2.90% Annual Growth
80 GWh
70 GWh
60 GWh
50 GWh
40 GWh
30 GWh
20 GWh
1978
1982
1986
1990
1994
1998
2002
2006
2010
2014


DECEMBER DEMAND PROJECTION
2.79% Annual Growth
160 MW
140 MW
120 MW
100 MW
80 MW
60 MW
40 MW
1978
1982
1986
1990
1994
1998
2002
2006
2010
2014
47
49
51
52
50
61
61
60
60
64
64
72
74
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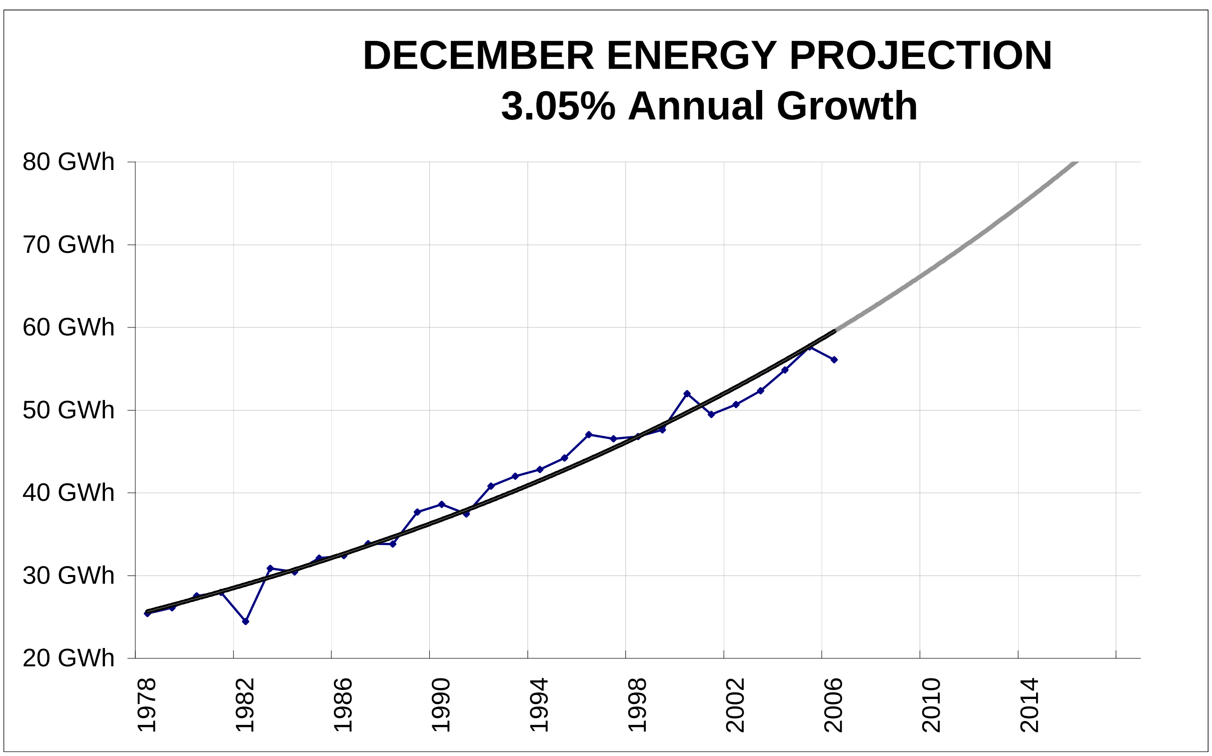
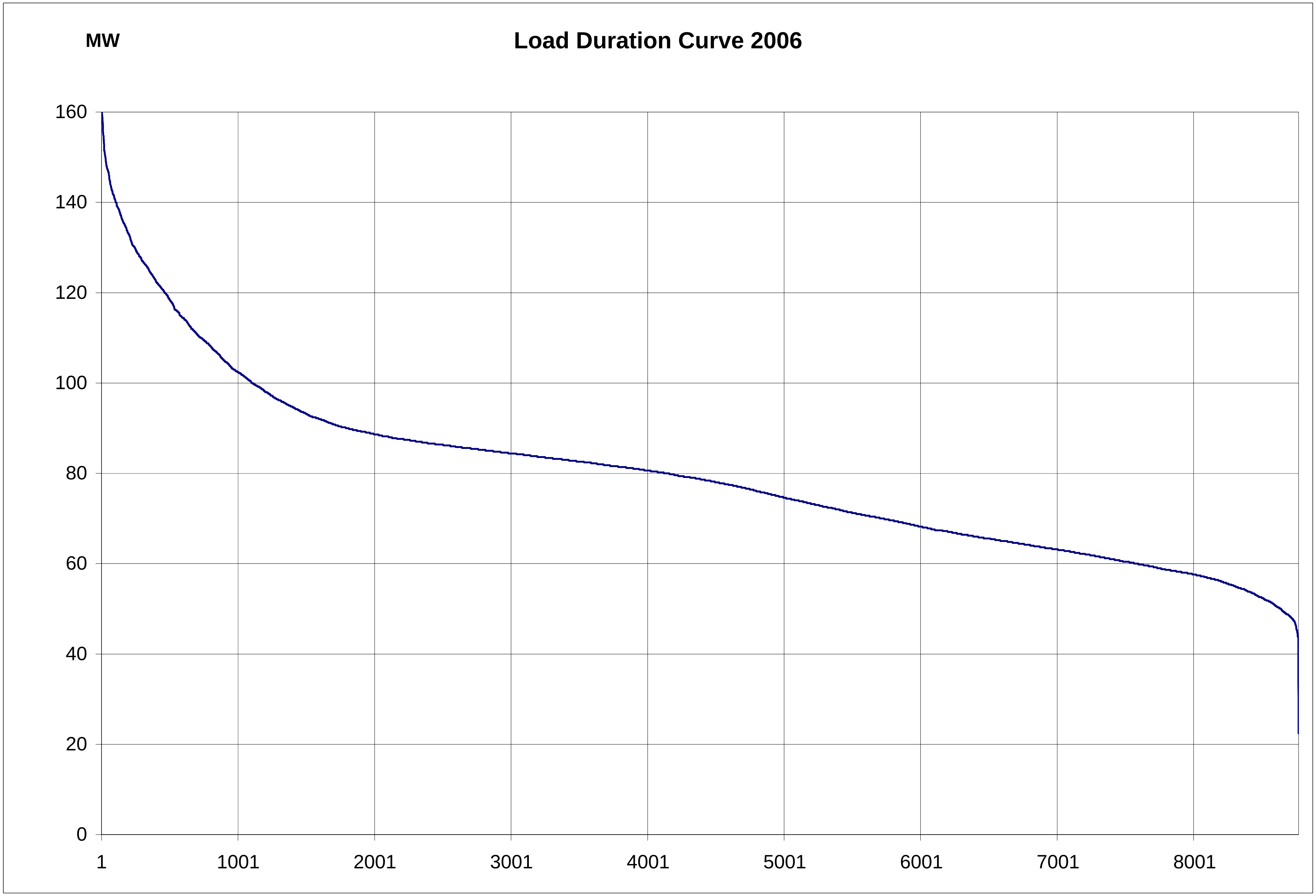
89
91
95
99
106
100


DECEMBER ENERGY PROJECTION
3.05% Annual Growth
80 GWh
70 GWh
60 GWh
50 GWh
40 GWh
30 GWh
20 GWh
1978
1982
1986
1990
1994
1998
2002
2006
2010
2014


MW
Load Duration Curve 2006
160
140
120
100
80
60
40
20
0
1
1001
2001
3001
4001
5001
6001
7001
8001

APPENDIX “D”

ORDINANCE NO. 9089

An ordinance to authorize and Amended and Restated Participation Agreement with Public Power Generation Agency; to repeal any ordinance or parts of ordinances in conflict herewith; and to provide for publication and the effective date of this ordinance.

WHEREAS, the City Council of the City of Grand Island (the "City") heretofore approved a Participation Agreement with the Public Power Generation Agency relating to Whelan Energy Center Unit 2; and

WHEREAS, it is necessary and desirable that the Participation Agreement be amended and restated; and

WHEREAS, a form of an Amended and Restated Participation Agreement has been presented to the City Council.

BE IT ORDAINED BY THE MAYOR AND COUNCIL OF THE CITY OF GRAND ISLAND, NEBRASKA:

SECTION 1. The execution and delivery of an Amended and Restated Participation Agreement by the Mayor of the City of Grand Island is hereby authorized in substantially the form presented, with such changes as such signatory approves, execution and delivery to be conclusive evidence of such approval.

SECTION 2. This ordinance shall be in force and take effect from and after its passage and publication, within fifteen days in one issue of the Grand Island Independent as provided by law.

Enacted: November 14, 2006.

Jay Vavricek, Mayor

Attest:

RaNae Edwards, City Clerk

Approved as to Form ¤ DAS
November 13, 2006 ¤ City Attorney

cc: Tim L- PGS

⑧
PPGA

RESOLUTION 2005-297

WHEREAS, the City of Grand Island is a project participant in the Whelan Energy Unit No. 2 power plant to be constructed in Hastings, Nebraska; and

WHEREAS, the Public Power Generating Agency is the governing body of the new power plant project; and

WHEREAS, on September 13, 2005, by Resolution 2005-248, the City Council of the City of Grand Island designated Timothy Luchsinger to be the City's representative on the Board of Directors of the Public Power Generating Agency of the Whelan Energy Center Unit No. 2 power plant project; and

WHEREAS, in order to ensure that the Board has sufficient attendance to conduct business at all times, it is requesting that an Alternate Board Representative be appointed by each of the participating utilities; and

WHEREAS, it is recommended that Utilities Director Gary Mader be designated as the Alternate Board Representative.

NOW, THEREFORE, BE IT RESOLVED BY THE MAYOR AND COUNCIL OF THE CITY OF GRAND ISLAND, NEBRASKA, that Utilities Director Gary Mader is hereby designated as the City of Grand Island's alternate representative on the Board of Directors of the Public Power Generating Agency Board of Directors.

- - -

Adopted by the City Council of the City of Grand Island, Nebraska, October 11, 2005.

RaNae Edwards

RaNae Edwards, City Clerk

subject

Approved as to Form	¤
October 5, 2005	¤ City Attorney

RESOLUTION 2005-248

WHEREAS, the City of Grand Island is participating in the development of a new base load, coal fired electric generating plant to be built in Hastings at the same site as an existing Hastings power plant; and

WHEREAS, the new power plant is named Whelan Energy Center Unit No. 2; and

WHEREAS, Grand Island is one of multiple public power utilities participating in this power plant project; and

WHEREAS, the legal governing agency of the project is the Public Power Generating Agency, which was created by the project participants in accordance with the State of Nebraska Interlocal Agreement statutes; and

WHEREAS, one Board Member is to be appointed to the Board of Directors of the Public Power Generating Agency by each of the project participants; and

WHEREAS, it is recommended that Assistant Utilities Director Timothy Luchsinger be designated as the City of Grand Island Board Member.

NOW, THEREFORE, BE IT RESOLVED BY THE MAYOR AND COUNCIL OF THE CITY OF GRAND ISLAND, NEBRASKA, that Assistant Utilities Director Timothy Luchsinger is hereby designated as the City of Grand Island representative on the Public Power Generating Agency Board of Directors of the Whelan Energy Center Unit No. 2 power plant project.

\- - -

Adopted by the City Council of the City of Grand Island, Nebraska, September 13, 2005.

RaNae Edwards

RaNae Edwards, City Clerk

re: Tim - P65
Subject ✓

Approved as to Form ¤	DRW
September 7, 2005 ¤	City Attorney

RESOLUTION 2005-224

WHEREAS, for the past four years, the City of Grand Island has been participating in the development of a new base load, coal fired electric generating plant to be built in Hastings at the same site as the existing Hastings plant; and

WHEREAS, the site is named the Whelan Energy Center (WEC) and the new project is generally referred to as WEC2; and

WHEREAS, the WEC2 capacity is designed to be 220 megawatts (MW), with the current Grand Island share to be 15 MW; and

WHEREAS, the legal governing agency of the project is the Public Power Generating Agency (PPGA), with one board member to be appointed from each project participant; and

WHEREAS, the creation of the Public Power Generating Agency includes the approval of three documents: the Interlocal Agreement, the Bylaws of the Public Power Generating Agency, and the Participation Agreement; and

WHEREAS, Grand Island's electric load, like that of the state in general, continues to grow; and

WHEREAS, in order to maintain a near optimum mix of electric generation resources for the future, base load capacity will need to be added; and

WHEREAS, the WEC2 project offers an opportunity to add electric base load capacity; and

WHEREAS, the City Attorney has reviewed and approved the above identified contract documents to participate in such project.

NOW, THEREFORE, BE IT RESOLVED BY THE MAYOR AND COUNCIL OF THE CITY OF GRAND ISLAND, NEBRASKA, that the City of Grand Island is hereby authorized to participate in the Whelan Energy Center Unit No. 2 power plant project.

BE IT FURTHER RESOLVED, that the Public Power Generation Agency Participation Agreement, Interlocal Agreement, and Bylaws of the Public Power Generation Agency are hereby approved; and the Mayor is hereby authorized and directed to execute such documents on behalf of the City of Grand Island.

\- - -

Adopted by the City Council of the City of Grand Island, Nebraska, August 9, 2005.

Paul M. Briseno Deputy City Clerk

RaNae Edwards, City Clerk

Approved as to Form ¤ DRW	
August 2, 2005 ¤ City Attorney	

RESOLUTION 2004-77

WHEREAS, the City of Grand Island has been participating in the development of a new base load, coal fired electric generating plant to be built in Hastings at the same site as the existing Hastings plant; and

WHEREAS, the site is named Whelan Energy Center, and the new project is generally referred to as WEC2; and

WHEREAS, the City is intending to participate in such project at a level of 15MW; and

WHEREAS, Phase 1 of the project is now complete, and Phase 1.5 is proposed to continue project development in the following areas:

- Initiation of the preconstruction ambient air particulate monitoring as required by the construction permit
- Initiation of detailed plant design to maintain the permit requirement to begin construction within 18 months of the permit date
- Making application to the Nebraska Power Review Board for project approval as required by state law
- Initiation of the transmission service study for plant output delivery to all participants; and

WHEREAS, the total cost of Phase 1.5 is projected to be $375,000, with the City's share not to exceed $40,000; and

WHEREAS, it is recommended that the City enter into a Financial Commitment Agreement for Phase 1.5 of such project; and

WHEREAS, the City Attorney has reviewed and approved the Financial Commitment Agreement.

NOW, THEREFORE, BE IT RESOLVED BY THE MAYOR AND COUNCIL OF THE CITY OF GRAND ISLAND, NEBRASKA, that the Financial Commitment Agreement among the Municipal Energy Agency of Nebraska (MEAN) and Hastings Utilities for financial assistance for Phase 1.5 costs for the scope of work outlined above is hereby approved.

pc: Dale Subject

Approved as to Form ¤	JRL
April 8, 2004	¤ City Attorney

BE IT FURTHER RESOLVED, that the Mayor is hereby authorized and directed to execute such agreement on behalf of the City of Grand Island.

- - -

Adopted by the City Council of the City of Grand Island, Nebraska, April 13, 2004.

RaNae Edwards

RaNae Edwards, City Clerk

RESOLUTION 2003-33

WHEREAS, the Municipal Energy Agency of Nebraska (MEAN), Hastings Utilities (Hastings) and the City of Grand Island (City) are investigating the possibility of participating in a project to build a new generating unit in Hastings, Nebraska, and;

WHEREAS, the parties during the course of discussions may disclose to each other information which would otherwise be deemed confidential, and;

WHEREAS, in order to ensure that discussions are carried out in a frank and useful manner, it is necessary and appropriate that the parties agree to protect the confidential nature of such information, and;

WHEREAS, on July 10, 2001, by Resolution 2001-183, the City of Grand Island approve a Non-Disclosure Confidentiality Agreement by and between the City and the Municipal Energy Agency of Nebraska (MEAN) and the Hastings Utilities to enter into discussions to explore the possibility of participating in a project to build a new generating unit at Hastings, according to the terms of the agreement; and

WHEREAS, such agreement has expired, and the parties to the initial agreement wish to extend such agreement for an additional five-year term.

NOW, THEREFORE, BE IT RESOLVED BY THE MAYOR AND COUNCIL OF THE CITY OF GRAND ISLAND, NEBRASKA, that the Non-Disclosure Confidentiality Agreement by and between the City and the Municipal Energy Agency of Nebraska and the Hastings Utilities as set out above is hereby approved for a five-year term

BE IT FURTHER RESOLVED, that the Mayor is hereby authorized and directed to execute such agreement on behalf of the City of Grand Island.

- - -

Adopted by the City Council of the City of Grand Island, Nebraska, January 28, 2003.

RaNae Edwards

RaNae Edwards, City Clerk

pc: Burke
File
MEAN ✓

Approved as to Form ¤ JMS	
January 24, 2003	¤ City Attorney

RESOLUTION 2001-240

WHEREAS, the Municipal Energy Agency of Nebraska (MEAN) and Hastings Utilities are investigating the possibility of constructing a coal fired power plant in Hastings; and

WHEREAS, several area electric suppliers expressed interest in plant participation; and

WHEREAS, based on such interest by area electric suppliers, the sponsors have decided to proceed with a formal feasibility study for the project; and

WHEREAS, the study is intended to evaluate environmental permitting, conceptual engineering design, area transmission capability, legal requirements and other important issues associated with the proposed project; and

WHEREAS, it would be prudent for the City of Grand Island to evaluate and investigate the opportunities that such power plant would provide; and

WHEREAS, participation in the feasibility study is not a commitment to plant participation; and

WHEREAS, the City's share of such financial commitment is estimated at $67,500.

NOW, THEREFORE, BE IT RESOLVED BY THE MAYOR AND COUNCIL OF THE CITY OF GRAND ISLAND, NEBRASKA, that the Financial Commitment Agreement Among Municipal Energy Agency of Nebraska and Hastings Utilities for financial assistance for the feasibility study for the construction of a coal fired power plant in Hastings, Nebraska is hereby approved, and the Mayor is hereby authorized and directed to execute such agreement on behalf of the City of Grand Island.

- - -

Adopted by the City Council of the City of Grand Island, Nebraska on September 11, 2001.

RaNae Edwards

RaNae Edwards, City Clerk

Approved as to Form ▼	CJE
September 6, 2001 ▲	City Attorney

c: Burhl
Tim
pp

RESOLUTION 2001-183

WHEREAS, the Municipal Energy Agency of Nebraska (MEAN), Hastings Utilities (Hastings) and the City of Grand Island (City) wish to explore the possibility of participating in a project to build a new generating unit in Hastings, Nebraska, and;

WHEREAS, the parties during the course of discussions may disclose to each other information which would otherwise be deemed confidential, and;

WHEREAS, in order to ensure that discussions are carried out in a frank and useful manner, it is necessary and appropriate that the parties agree to protect the confidential nature of such information, and;

WHEREAS, the parties desire to enter into a non-disclosure confidentiality agreement in furtherance of their mutual interests in protecting their respective confidential information, and;

WHEREAS, a proposed agreement between the City and MEAN has been reviewed and approved by the City Attorney's office.

NOW, THEREFORE, BE IT RESOLVED BY THE MAYOR AND COUNCIL OF THE CITY OF GRAND ISLAND, NEBRASKA, that the Mayor is hereby authorized and directed to sign on behalf of the City of Grand Island, the Non-Disclosure Confidentiality Agreement by and between the City and the Municipal Energy Agency of Nebraska (MEAN) to enter into discussions to explore the possibility of participating in a project to build a new generating unit in the City of Grand Island, according to the terms of the agreement.

- - -

Adopted by the City Council of the City of Grand Island, Nebraska on July 10, 2001.

RaNae Edwards

RaNae Edwards, City Clerk

Approved as to Form ▼ DWS
July 6, 2001 ▲ City Attorney

pc: Burkle ✓
Tim
Bob
NMPP

INTEROFFICE MEMORANDUM

CITY OF GRAND ISLAND

Working Together for a Better Tomorrow. Today.

DATE: July 3, 2001

TO: Mayor and Council Members

FROM: Gary R. Mader, Utilities Director GM

SUBJECT: Future Power Supply Options

Background:
Hastings Utilities (HU) and Municipal Energy Agency of Nebraska (MEAN) are exploring the possibility of construction of a coal fired power plant at the Hastings Energy Center. The time line of this venture matches Grand Island's projected need to add base load capacity to its generation mix and the Utilities Department has asked HU and MEAN to consider participation by Grand Island.

Discussion:
As you will recall, the new 80 MW combustion turbine addition optimizes the City's generation mix until approximately 2012. At that time base load capacity will be needed to continue to meet growth in electric demand. Additionally, base load capacity is over twice as expensive as peaking capacity and therefore has the potential to more severely impact the economics of the utility.

Recommendation:
Given the high cost of base load generating capacity, it seems prudent to explore methods to minimize the exposure and risk of these high cost plants by joint ventures. It is the recommendation of the Utilities Department that we continue to participate in the development of this potential project and agree to accept the Confidentiality Agreement (copy attached).

Fiscal Impact:
None at this time.

Alternatives:
Do not participate in project development.

GRM/pag

STATE OF NEBRASKA

POWER REVIEW BOARD

Timothy J. Texel
Executive Director
and General Counsel
301 Centennial Mall South
P.O. Box 94713
Lincoln, Nebraska 68509-4713
Phone (402) 471-2301
Fax (402) 471-3715
www.nprb.state.ne.us

Mike Johanns
Governor

January 7, 2005

JAN 2005
RECEIVED
UTILITIES
DEPARTMENT

Gary Mader
Utilities Director
City of Grand Island
PO Box 1968
Grand Island, NE 68802-1968

Dear Gary:

Enclosed please find a copy of the Order demonstrating the Nebraska Power Review Board's approval of a joint application for authority to construct a 220 megawatt coal-fired generation facility in Adams County, Nebraska, for which the City of Grand Island is a co-applicant. As you are already aware, the Board voted to approve the application during its public meeting held December 3, 2004.

I apologize for taking so long to prepare the Order. I very much appreciate the patience that you and the other applicants showed while the Order was drafted. If you have any questions, please contact me at the phone number or address listed above.

Sincerely,

NEBRASKA POWER REVIEW BOARD

Timothy J. Texel

Timothy J. Texel
Executive Director

Enclosure

STATE OF NEBRASKA

POWER REVIEW BOARD

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Executive Director
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Fax (402) 471-3715
www.nprb.state.ne.us

Mike Johanns
Governor

November 18, 2004

11/24/04 PS

WEC #2

cc: Power Review Board file

NOV 2004
RECEIVED
UTILITIES
DEPARTMENT

Gary Mader
Utilities Director
City of Grand Island
PO Box 1968
Grand Island, NE 68802-1968

Dear Mr. Mader:

Enclosed please find a notice of hearing regarding a joint application for authority to construct a 220 megawatt coal-fired generation facility in Adams County, Nebraska, for which the City of Grand Island through the Grand Island Utilities is a co-applicant. In addition to the other co-applicants, this notice is also being sent to the cities of Blue Hill, Fremont, Lincoln, and Red Cloud, all in Nebraska, and the Village of Campbell, Nebraska, as alternate power suppliers potentially affected by the application. The notice will also be published once in both the *Omaha World-Herald* and *Hastings Tribune* newspapers.

The Board is providing the City of Grand Island with official notice of the hearing on this matter pursuant to the requirements set out in Neb. Rev. Stat. § 70-1013.

Sincerely,

NEBRASKA POWER REVIEW BOARD

Timothy J. Texel

Timothy J. Texel
Executive Director

Enclosure

SEP 1 9 2003

PUBLIC NOTICE OF PUBLIC HEARING

Nebraska Department of Environmental Quality

Air Quality Division

On August 12, 2003, notice was given to the public of the Department's intent to issue a construction permit to Hastings Utilities for permission to construct a 220 Megawatt coal-fired electric generating unit (SIC Code 4911) at the Whelan Energy Center located at 4520 East South Street in Hastings, Nebraska. This public notice was provided in accordance with Chapter 14 of Title 129 – Nebraska Air Quality Regulations.

During the public notice period, comments and concerns were raised and a public hearing was requested. The comments and concerns received by the Department include, but are not limited to, the following issues:

- Pre-application ambient air monitoring requirements
- Air Dispersion Modeling protocol and results

Notice is now given pursuant to Nebraska Administrative Code, Title 129 – Nebraska Air Quality Regulations, Chapter 14, Section 005, and Title 115 – Rules of Practice and Procedure, Chapter 5, Section 003, the Department will hold a public hearing on the proposed permit. The public hearing will be held on Thursday, November 6, 2003, at 7.30 P.M. at the Central Community College, East Highway 6, in the Dawson Building Gymnasium in Hastings. Preceding the hearing, representatives of the Department will hold an information session from 6:00 to 7:00 P.M. to answer questions from the public related to the proposed permit.

The proposed permit and supporting materials are available for inspection at the office of the Nebraska Department of Environmental Quality, Suite 400, The Atrium, 1200 "N" Street, Lincoln, Nebraska 68508. These materials were also forwarded to the Hastings Public Library. Telephone inquiries may be made at (402) 471-2189. Please notify the Department of Environmental Quality if alternate formats of materials are needed no later than October 27, 2003. Contact phone number is (402) 471-2186. TDD users please call 711 and ask the relay operator to call us at (402) 471-2186. Persons requiring further information should contact:

W. Clark Smith-Permitting Section Supervisor
Air Quality Division
Nebraska Department of Environmental Quality
PO Box 98922
Lincoln, NE 68509-8922