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Rural Development Utilities Programs

Rural Electric Power Generation And Capacity Expansion

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Abbreviations/ Acronyms

AEO – Annual Energy Outlook

CCS – Carbon Capture and Sequestration

CERA – The Cambridge Energy Associates

CHP – Combined Heat and Power

DER – Distributed Energy Resources

EPRI – Electric Power Research Institute

ERCOT – Electric Reliability Council of Texas

FRCC – Florida Reliability Coordinating Council

G&T – Generation and Transmission

GW – Gigawatt

Hydro – Hydroelectric power

IOU – Investor Owned Utility

kWh – Kilowatt hour

MRO – Midwest Reliability Organization

MW – Megawatt

MWh – Megawatt hour

NERC – North American Electric Reliability Corporation

NPCC – Northeast Power Coordinating Council

NRECA – National Rural Electric Cooperative Association

OPEC – Organization of the Petroleum Exporting Countries

PCCI – Power Capital Costs Index

PHEV – Plug-In Hybrid Electric Vehicles

REA – Rural Electrification Administration

RFC – Reliability*First* Corporation

SERC – Southeastern Electric Reliability Council

SPP – Southwest Power Pool

TRE – Texas Regional Entity

WECC – Western Electricity Coordinating Council

1. SUMMARY

The Food and Energy Security Act of 2007 provided that the Secretary shall conduct a study on the electric power generation needs in rural areas of the United States and provided further the study should include an examination of:

1. generation in various areas in rural areas of the United States, particularly by rural electric cooperatives;
2. financing available for capacity, including financing through programs authorized un the Rural Electrification Act of 1936;
3. the impact of electricity costs on consumers and local economic development;
4. the ability of the fuel feedstock technology to meet regulatory requirements, such as carbon capture and sequestration; and
5. any other factors that the Secretary considers appropriate.

The demand for new generation capacity in rural areas is increasing just as it is in the urban centers. The last significant industry wide build-out of base load electric generation plants occurred during the 1970-1985 timeframe. Since that time the industry has moved from a situation of over capacity to the current period in which most utilities are forecasting the need to build new base load capacity to meet the requirements of their customers and in the case of rural electric cooperatives that means member/owners of the system.

In fact, due to the significant lead time necessary for the addition of new base load capacity, many utilities, including cooperatives, are behind the curve.

Due to current and projected growth, cooperatives will need to double generation capacity by 2020.

An additional reliability concern is the lack of transmission capacity to deliver energy from generation points to demand centers. The existing transmission grid is operating at capacity and many parts of the grid are operating beyond expected life cycles.

The lack of transmission capacity is also impeding the development of renewable energy resources in remote rural areas. The lack of transmission capacity in general and the capacity needed to move renewable energy was a consistent theme of a recent Senate Energy and Commerce hearing and it was a prominent theme of the Washington International Renewable Energy Conference (WIREC) held in Washington in March of this year.

2. BACKGROUND

Virtually no additional base load generation capacity was added during the 1990s and early in this century due to surplus capacity available from the previous construction cycle and the efforts to deregulate the electric power industry during the mid to late 1990s. Efforts to deregulate the industry created an atmosphere of significant uncertainty with regard to the expectation that the existing customer base would be there to ensure repayment of the investments.

Base load generation means those plants that are designed to be operated twenty four hours per day, seven days per week. They are shut down only for required maintenance. Base load plants are generally fueled by coal, nuclear, and sometimes natural gas. When base load plants cannot meet demand, intermediate facilities are started. These are typically fueled by natural gas and can be started as quickly as needed. The last in line are peaking plants that are also fueled by natural gas and also can be started quickly.

During this period the cooperative side of the industry attempted to keep pace with demand with investments in smaller natural gas peaking and intermediate facilities which are less costly to build, but very expensive to operate due to the price volatility of natural gas. Cooperatives also met demand by entering into power purchase contracts with other suppliers. Many of these contracts will expire in the near future, some as soon as 2011.

Since 2000 the uncertainty associated with deregulation of the industry has waned. This combined with favorable interest rates appeared to be an opportune time to invest in new capacity and the rural electric generation and transmission borrowers began developing plans for that investment. However, new uncertainties and challenges have since been introduced:

- It appears likely that some form of carbon dioxide emission limits will be imposed.
- Legal challenges to environmental permits can be expected on any new emitting base load plant.

- Costs of new plant construction are increasing substantially each year due to a variety of factors.

3. CURRENT GENERATION CAPACITY AND PEAK DEMAND

Rural Electric G&T cooperatives own 160 generating units totaling 38,604 Megawatts of generation capacity of which roughly 59% is from coal fired steam plants and about 6% represent partial ownership in nuclear plants and about 32% is primarily gas fired peaking or intermediate units.

Owned capacity represents 57% of the energy supplied to member distribution cooperatives. Purchases from other sources represent the other 43%. G&T cooperatives attempt to maintain this balance between self-generation and purchased power to minimize risk and maximize opportunities. At any given point in time if purchases can be secured at less marginal cost than that of operating a peaking or intermediate unit, then the cooperative will opt for purchases to meet the requirements of its members.

One reason that 59% of the capacity owned by these cooperatives is coal fired is that following the OPEC oil embargo of 1973 Congress enacted the Power Plant and Industrial Fuel Use Act which prohibited the use of oil or natural gas to generate electricity. This pushed investment to coal and nuclear energy during the last base load construction cycle in the late 1970s and early 1980s. This Act was repealed in 1987.

Another reason coal is the preferred fuel is cost. Currently, energy generated from coal is available at an average total cost of $34.02 per MWh. Gas fired combined cycle plants on the average produce energy at $96.60 per MWh while nuclear energy costs a little over $40.00 per MWh.

4. U.S. CAPACITY MARGINS

The mission of the North American Electric Reliability Corporation (NERC) is to ensure that the bulk power system in North America is reliable. NERC develops and enforces reliability standards; monitors the system; assesses and reports on future adequacy; and evaluates owners, operators, and users for reliability and preparedness.

In October of 2007, NERC released its report on Long Term Reliability Assessment which contained the following key findings:

- Long Term Capacity Margins are Still Inadequate
- Integration of Wind, Solar, and Nuclear Resources Require Special Consideration in Planning, Design, and Operation.
- High Reliance on Natural Gas in Some Areas of the Country Must be Properly Managed to Reduce Supply Risk and Delivery Interruption.
- Transmission Situation Improves, But More Still Required.
- Aging Workforce Still a Growing Challenge.

According to the report, peak demand for electricity in the U.S. is forecast to increase by over 135,000 MW or 17.7% in the next ten years while capacity is projected to increase by only 77,000 MW. Capacity margins, i.e., reliability margins, begin dropping below the recommended 15% above peak demand in 2009 and continue to decline to under 10% by 2016. The decline below 15% occurs first in the western third of the U.S. and Canada and the New England Area. A reserve of 15% is desirable to prevent brownouts or blackouts in case of unplanned outages of generation facilities, unusual weather events, or other unpredictable events occur.

The map below identifies the years when a region/subregion drops below target capacity margin levels required to meet summer peak (unless noted as winter) including both committed and uncommitted[1] resources. Those region/subregions not identified are not projected in the next ten years to drop below their target margin levels.

[1] **Uncommitted Capacity Resources:** Capacity resources that include one or more of the following: • Generating resources that have not been contracted nor have legal or regulatory obligation to deliver at time of peak.• Generating resources that do not have or do not plan to have firm transmission service reserved (or its equivalent) or capacity injection rights to deliver the expected output to load within the region.• Generating resources that have not had a transmission study conducted to determine the level of deliverability. • Generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources.• Transmission-constrained generating resources that have known physical deliverability limitations to load within the region.

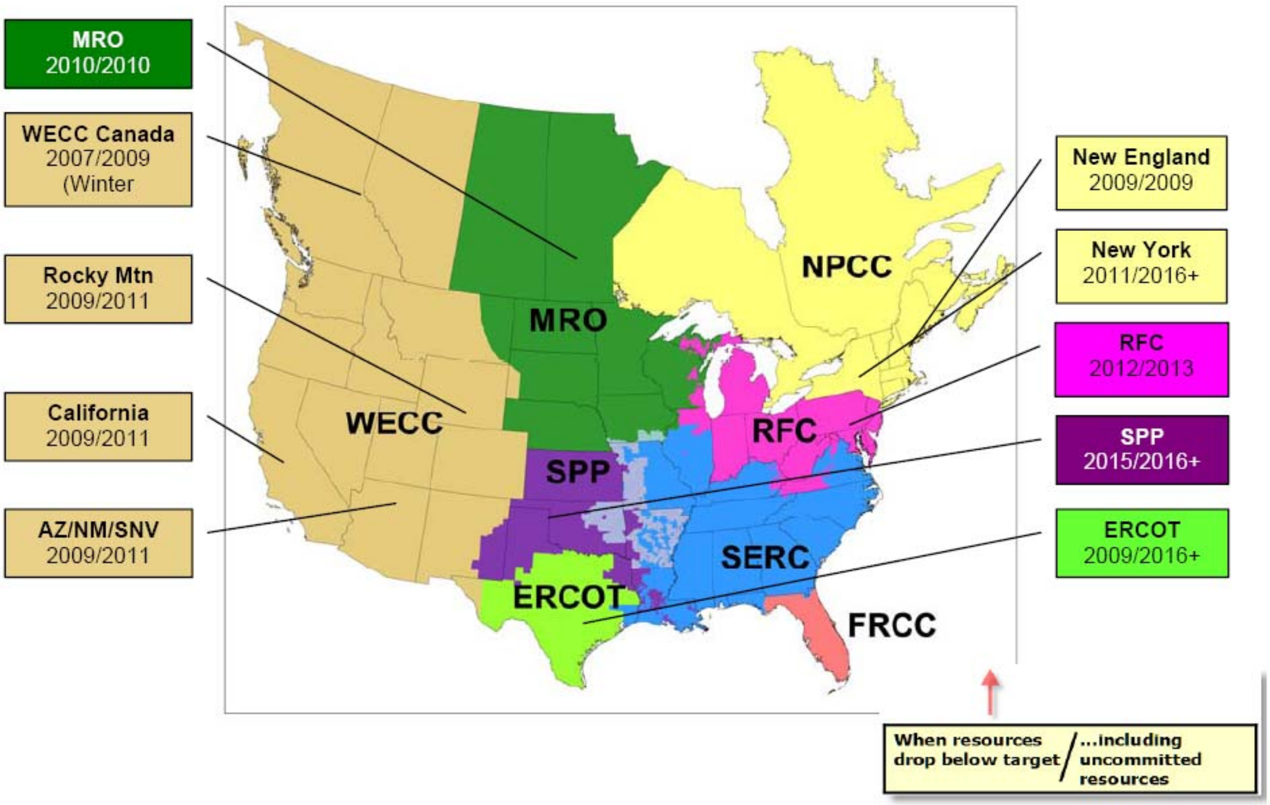

Figure 1 Regional Resources Drop Below 15% Target (Source: NERC)

5. U.S. AND RURAL ELECTRIC GENERATION AND TRANSMISSION FORECASTED GENERATION CAPACITY ADDITIONS

The U.S. Department of Energy's Annual Energy Outlook for 2008 forecasts electricity consumption to grow from 3.8 billion kilowatthours in 2006 to almost 5 billion kilowatthours in 2030, an annual rate of increase of 1.1 percent. The 2008 forecast is lower than the 2007 forecast of 1.5% annual increase due to slower economic growth, higher electricity prices and the enactment of new efficiency standards in the Energy Independence and Security Act of 2007.

The Cambridge Energy Associates, a private research firm, estimates the U.S. electric power industry will invest $900 billion in new utility plant over the next 15 years. This level of investment surpasses the total net plant in service today. This total includes $350 billion for new generation, $300 billion for distribution, $150 billion for transmission, $50 billion for conservation and efficiency and $50 billion for environmental retrofits (not including CO2 abatement).

Rural Areas

Presently, rural electric G&T cooperatives generate about 5% of the energy produced in the U.S. Every year the National Rural Electric Cooperative Association (NRECA) surveys its G&T members regarding their planned capacity additions. The most current survey indicates a 10 year capital requirement of $65.5 billion, $49.9 billion of which is specifically for new generation projects. Ten billion dollars are needed for new transmission and almost $3 billion is needed for environmental retrofits.

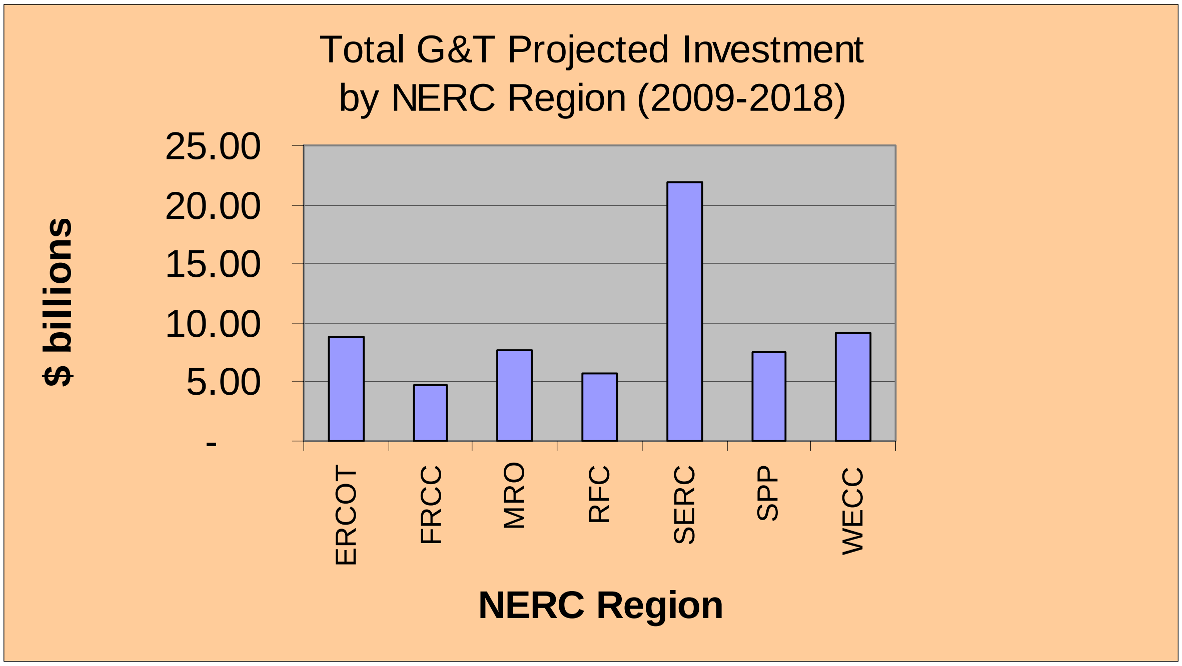

Figure 2 G&T Projected Investment by NERC Region (Source: NRECA)

The 2008 survey projects significantly higher capacity needs than the 2007 survey of 22,000 MW versus 14,000 MW primarily because the timing of larger investments in base load have been shifted to later years. The survey results suggest that the needs in the shorter term will be filled with natural gas fired peaking and intermediate units.

The delay in the construction of base load facilities is a reaction to the uncertainties of increasing construction costs, legal challenges, and regulation of carbon dioxide emissions.

While adding additional natural gas fired units in the shorter time frame is not seen as an optimal solution, this capacity will aid in meeting the energy requirements of cooperative consumers. The price of natural gas has been volatile and steadily increasing since 2000 and additional demand will add to the price volatility.

6. CONSTRUCTION COST

According to the Cambridge Energy Research Associates Power Capital Cost Index, the cost of new power plant construction has increased 130% during the past eight years with almost 70% of the increase occurring since 2005. The demand for material in China and India is a huge factor, but other supply constraints and increasing labor cost are also key factors. Earlier this year one of the Generation and Transmission Cooperative borrowers shelved a project that had been in the planning stage for three years because the projected cost had risen from $1.4 billion to over $1.8 billion. Given a four year construction period the cost would have been over $2 billion.

The time horizon for large base load facilities can easily be ten years from the beginning of planning to commercial operation. Construction time alone can be four years. Making huge investment decisions with these time horizons is very difficult given the uncertainties discussed above. Adding to these uncertainties is the current disruption in the commercial financial markets.

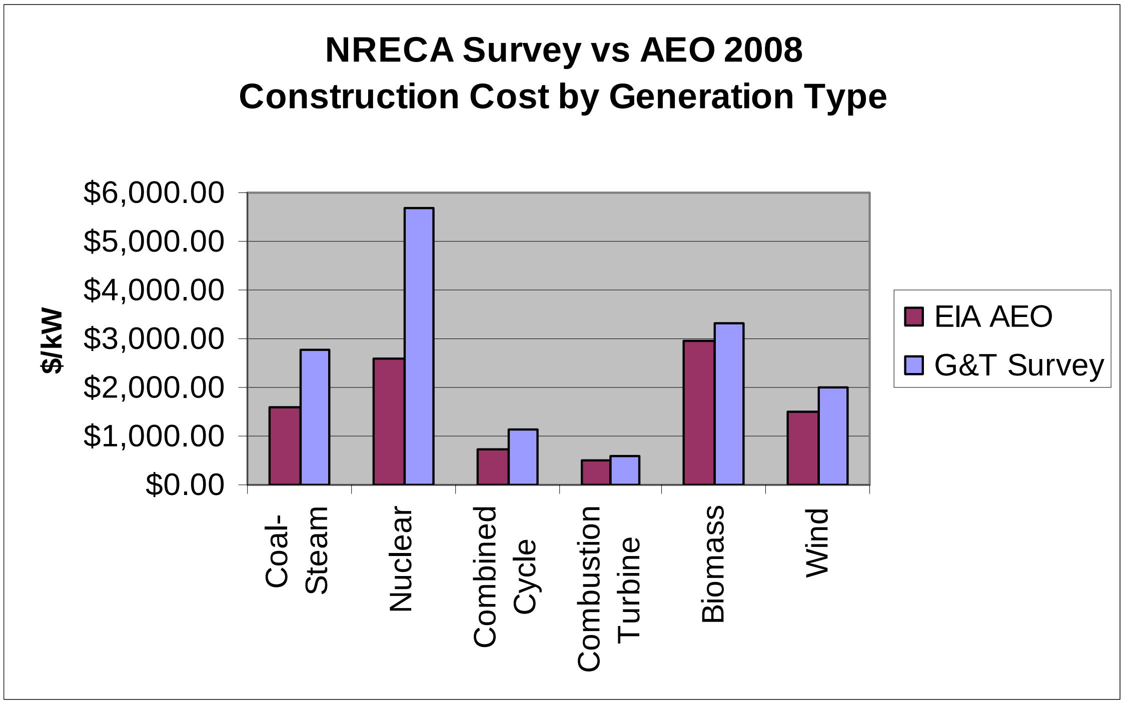

Figure 3 Comparison of AEO vs. Reported Construction Cost

7. NEW GENERATION OPTIONS AND COSTS

G&T cooperative planning is currently in a state of fluctuation. Rising construction costs, legal challenges to permits, and uncertainty related to CO2 mitigation and financing options have once again created difficult circumstances for decision making by utility executives. The central mission of cooperative utilities is to provide affordable and reliable power to their membership. More than anything, utility executives would like to have reduced uncertainty in order to make the best possible decisions to accomplish their missions.

G&T cooperatives maintain ongoing planning activities and constantly re-evaluate options for supply and demand side resources as new information emerges and market conditions change. G&T borrowers and the industry as a whole are faced with difficult decisions as they attempt to reconcile increasing energy demand requirements with the current realities in power generation planning. In particular, the problem G&T cooperatives face in attempting to price CO2 emissions into least cost planning models has created a situation in which it is difficult to know with any certainty what the final delivered cost of energy will be. Adding to this is the very steep upward curve with respect to construction costs. Even if a cost escalation factor is applied, legal challenges to air permits and other regulatory approvals can make it difficult to determine how long it will take to resolve these issues, and therefore how far along the costs escalation curve a project will be at the time of construction. Finally, the Electric Program's current inability to fund base load projects provides more uncertainty related to the cost of capital, a major component in the costs structure behind electricity pricing in a cost based regulatory environment.

Meaningful options for new base load generation are limited. Most proposed nuclear development is at existing plants, with existing owners as participants. Traditional coal fired generation is problematic due to the factors addressed above. A significant point that must be addressed by policy makers is the technology gap between what is desired to address climate change and what is economically and commercially proven. Advanced coal and carbon capture technologies are in their infancy and require significant demonstration and research at utility scale before they can be widely adopted.

Planned Additions

The latest information available from G&T cooperatives is indicative of the current level of uncertainty utilities face. The NRECA 2008 Survey estimates new generation projects totaling 22,067 MW are needed. The following figure breaks these generation investments into 5 categories: coal, combined cycle, combustion turbine, nuclear, and renewable. Combined cycle and combustion turbine projects are generally considered to be fueled by natural gas.

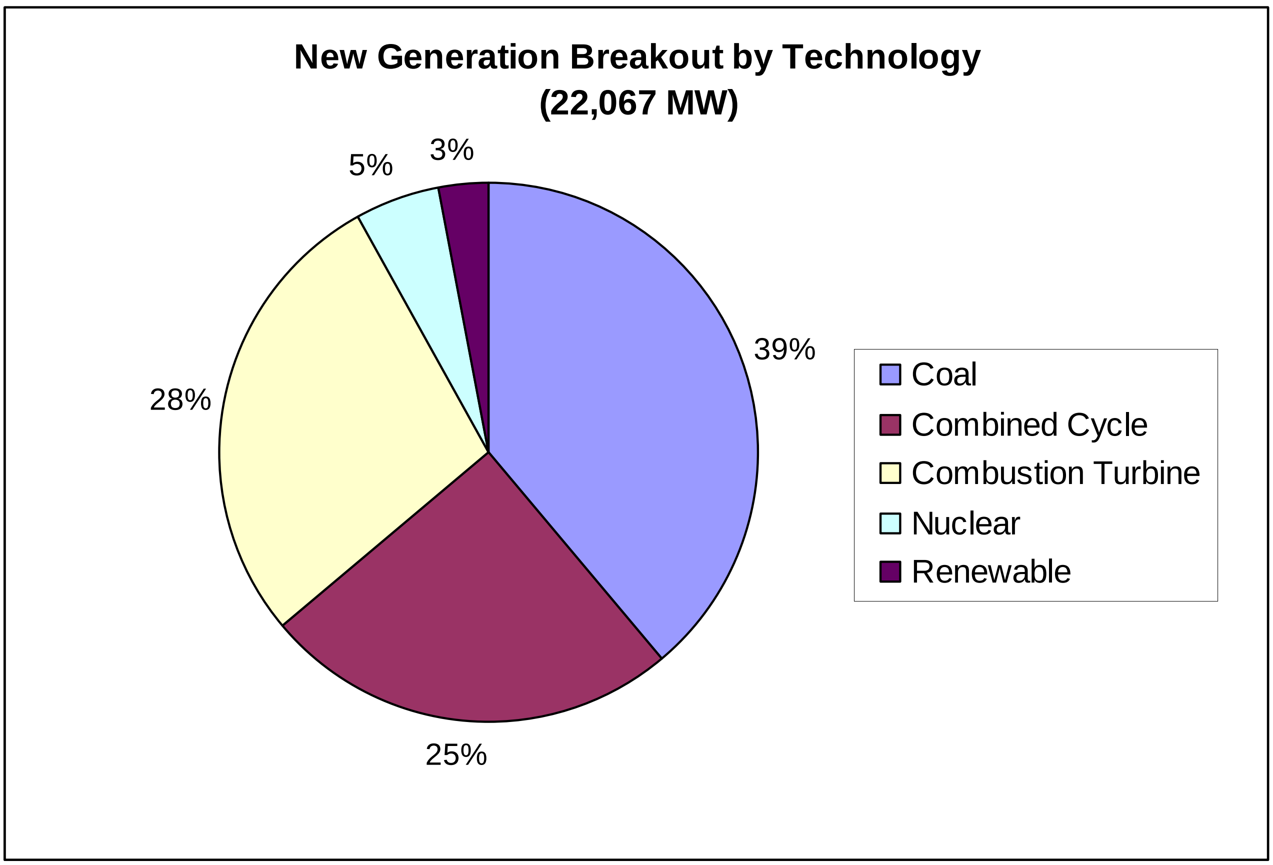

Figure 4 NRECA Survey - G&T New Generation by Fuel Type

The 2008 prediction for MW needed is significantly higher than the 2007 survey, which estimated 14,000 MW. The primary reason for this dramatic increase has to do with a change in the timing of large investments in fossil (coal) steam plants. Large base load coal plants have been shifted to the later years of the survey. The gap created by this shift in planned capacity additions has been filled with natural gas fired combined cycle and combustion turbine technology. The 2007 NRECA survey predicted a mix of 70% coal vs. 39% for the 2008 survey. Natural gas fired generation, including combined cycle and combustion turbine, now represents 53% of the total projected capacity needs or 11,695 MW.

The Upside and Downside of Natural Gas

The shift in the planned construction of base load facilities is a reaction to conditions in the market for plant construction, the policy uncertainties surrounding CO2 emitting resources, and uncertain long term financing for base load plants. The following table shows the differences in CO2 output from various electric power fuel sources[2].

Fuel	**Output Rate** (pounds CO2 per kWh)
Coal	2.11
Petroleum	1.92
Natural Gas	1.31
Other Fuels	1.38

Table 1 CO2 Output Rates for Power Generation Fuels

[2] Carbon Dioxide Emissions from the Generation of Electric Power in the United States, July 2000, Department of Energy, Washington, DC 20585, Environmental Protection Agency, Washington DC 20460

Natural gas fired plants emit less than two thirds the amount of CO_2 than do traditional coal fired plants. They are relatively inexpensive (compared to traditional base load options) to construct and can come on line in less than two years. These plants are also not drawing the same level of negative attention that proposed coal fired units are getting. While legal challenges, and uncertainties exist with respect to CO_2 regulation, adding additional gas fired generation at this time, is not seen by all as optimal. The following figure shows the dramatic increases in natural gas prices seen over the past 10 years. Increases in gas fired capacity to date have contributed to significant volatility and upward pressure on rates to cooperative customers.

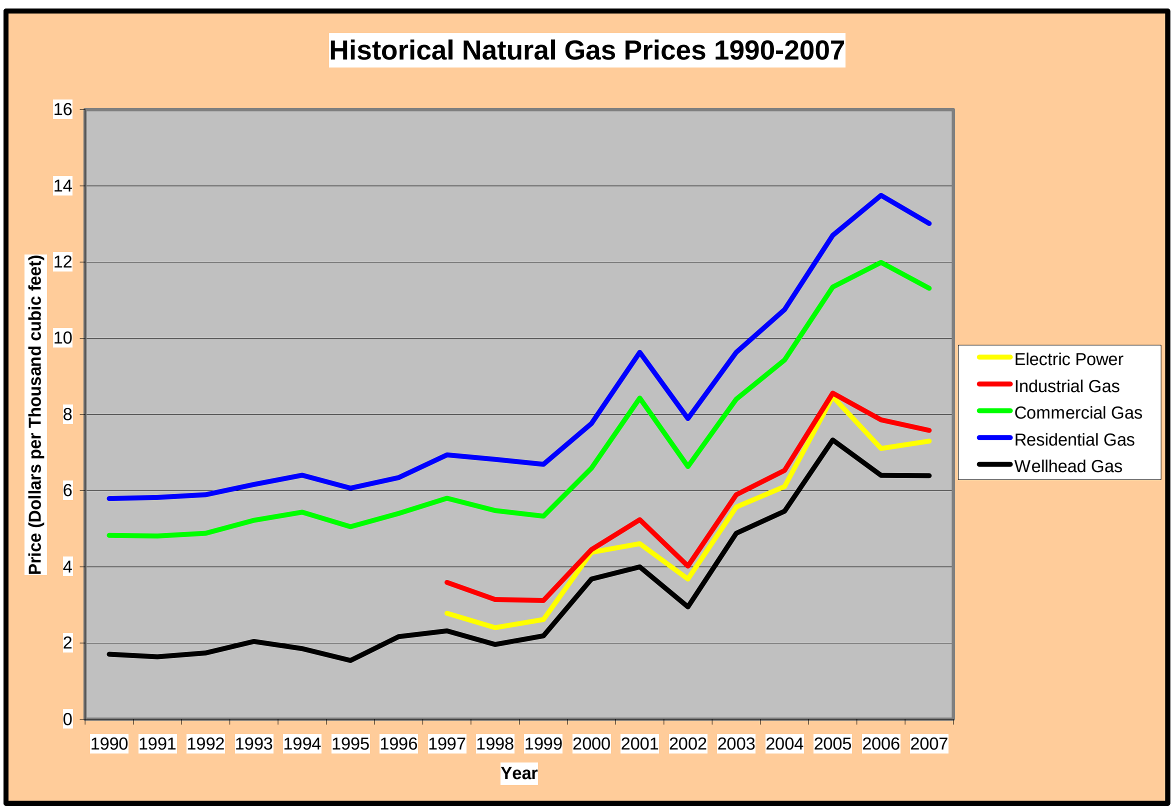

Figure 5 Historical Natural Gas Prices 1990 - 2007

Nuclear Power

Seven G&T cooperatives are currently minority participants in the ownership of nuclear assets. Like their investor owned utility and municipal counterparts, G&T cooperatives that are participants in existing nuclear projects are considering further participation as new units are proposed. The Nuclear Regulatory Commission currently has 23 applications in house for 34 new nuclear power plants. G&T cooperatives are currently planning participation totaling 1,103 MW of new nuclear power generation.

Renewable Energy

Renewable energy is projected to be 662 MW of expected G&T capacity additions at this time. G&T cooperatives are also in the process of creating a new national renewable energy cooperative for the purpose of investing in renewable projects nationwide. G&T cooperatives have long been partners in wind projects as power purchasers. Nationwide, co-ops own 450 MW in renewable energy generation and have power purchase contracts for 700 MW of renewable energy generation for a combined total of 1150 MW.

8. FINANCING OPTIONS AND COSTS FOR GENERATION AND TRANSMISSION COOPERATIVES

The majority (68%) of long term debt held by G&T cooperatives has been provided by the Rural Utilities Service electric program. For most of these entities, this source of financing is the preferred option due to the interest rate differential and term length differences between government financing and commercial capital. Given the magnitude of these investments, the choice of lending sources can mean billions of dollars in interest costs as shown below. Higher interest costs will, of course, be absorbed by the rural electric members in the form of higher rates.

Why Is This Source of Financing Critical To Rural Consumers?

On average the cost of generation and transmission represents 65% of the electric bills at the rural retail level. Primarily residential, rural electric distribution cooperatives serve 7.0 consumers per mile of distribution line compared to 35.1 for investor owned utilities and 46.6 for municipally owned systems. Translated into revenue per mile of line distribution cooperatives average $10,565 compared to $62,665 for investor owned utilities and $86,302 for municipally owned systems. Due to the low density of the customer base, the cost of energy, and the fact that most of the energy consumed is for residential usage, the rates paid by distribution cooperative consumers average about 10% higher than neighboring investor owned and municipally owned systems.

The following figure highlights the relationship between wholesale power cost and a typical distribution cooperative's total costs. Distribution costs are typically 35% of total cost, while 65% is the cost of power purchased by the distribution cooperative for resale to its retail customers.

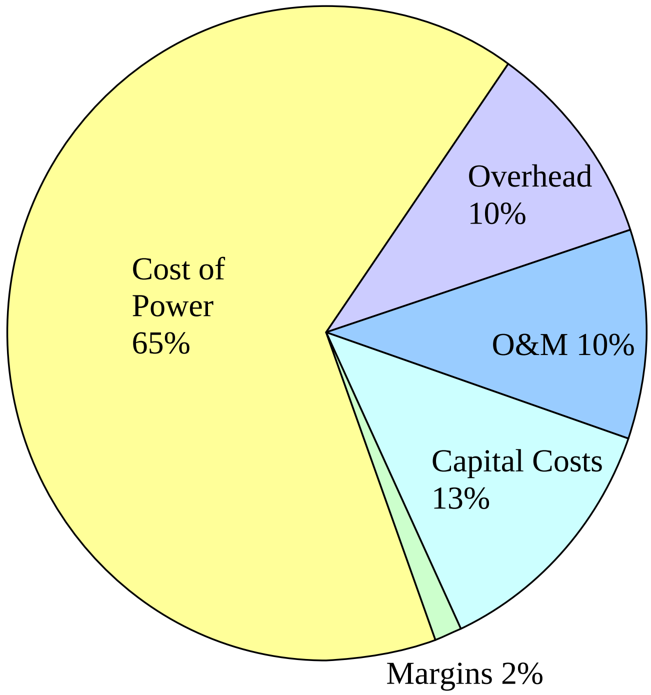

Figure 6 Distribution Cooperative Total Cost

Cooperative sales are heavily weighted towards the residential customer class. The following table shows that 57.49% of total cooperative sales are to residential customers. This compares with 35.90% and 37.44% for municipal and investor owned utility types.

Sales (MWh)	Investor Owned	Municipal Owned	Cooperatives
Residential	848,430,553	149,977,282	212,951,324
Commercial	825,907,980	157,732,964	75,038,401
Industrial	589,490,958	109,788,625	82,419,789
Transportation	2,335,674	279,849	0
Total	**2,266,165,165**	**417,778,720**	**370,409,514**

Table 2 MWh Sales by Utility Type

Due to the lower revenue per mile of distribution line, it is imperative that the G&T cooperatives seek the least costly source of capital.

The Electric Program finances intermediate and peaking generators, improvements and environmental retrofits to existing generation plants, transmission, and renewable energy projects as well as distribution system improvements. These improvements involve no risk, so there is no subsidy costs currently associated with these investments. Another factor contributing to negative subsidy rates is the fact that there is less than one-tenth of one percent delinquency rate on a portfolio exceeding $36 billion.

The following table demonstrates the magnitude of the costs of borrowing for new electric power generation ($49.9 billion) under various interest rate and term length scenarios. The following calculations are meant to illustrate only the magnitude of potential interest expense related to capital intensive infrastructure projects such as power plant construction. Any number of factors will affect the actual costs of these investments. This example makes several simplifying assumptions in order to illustrate interest expense only:

- The full amount of the construction program ($49.9B in principal) is advanced on day one
- Payments are all quarterly
- No interest only or balloon options
- 100% debt financing
- The current 30 year estimated Electric Program annual interest rate is 4.36%

- The current 15 year Electric Program annual interest rate is estimated using the simple average of the posted 10 and 20 year Treasury rates or 4.11%

Interest costs are undiscounted; therefore caution should be exercised in comparing loan costs across term lengths.

Potential Interest Costs of G&T Generation Plant Investments			
	Electric Program Financing	Private Financing w/ 250 Basis Point Difference	Private Financing w/ 350 Basis Point Difference
Estimated Capital Needs w/ 30 year Amortization	$ 39,790,042,639.01	$ 68,133,472,884.59	$ 80,374,473,244.68
Estimated Capital Needs w/ 15 year Amortization	$ 17,200,230,555.21	$ 29,139,749,493.62	$ 34,210,098,613.80

Table 3 Interest Rate and Term Affects on Capital Costs

9. RENEWABLE ENERGY

Renewable energy, including hydropower, totals around 8% of the nation's electricity production while coal and nuclear combined total 68% and natural gas 22%. For electric cooperatives renewable energy, primarily large hydro facilities, accounts for 11%, coal accounts for 62%, nuclear 15%, natural gas 10% and diesel fuel 2%. Renewable energy is becoming a larger portion of the cooperative portfolio.

Presently 80% of the 900 rural electric cooperatives supply some of their electricity needs from renewable sources, owning or purchasing 1,415 MW, primarily wind. A little over 1,000 additional MW (wind and woody biomass) is being planned. Close to 150 cooperatives either own wind turbines or purchase output from wind farms. Great River Energy based in Minnesota is the cooperative leader with 218 MW of purchased wind energy and is planning to add additional wind resources.

Basin Electric based in North Dakota purchases 136 MW from three commercial wind farms and is planning to build and own another 200 MW of wind energy.

Renewable Portfolio Standards (RPS) adopted by several states have had a significant impact on the deployment of renewable generation. Twenty six states and the District of Columbia have passed RPS requiring utilities to add increasing amounts of renewable energy ranging from 10 to 25 percent to their energy mix. Other states have adopted renewable goals rather than mandates.

Renewable energy resources are to a large extent found in remote rural areas and to develop those resources more fully and to deliver the energy to market centers will require substantial investments in transmission capacity both in terms of delivering renewable energy to the transmission grid and increasing the capacity of the grid to handle increasing loads. As pointed out earlier, the existing transmission grid is essentially operating at or above capacity today. In order to meet the increased demand that is projected has been well stated by the Chief Executive Officer of NERC, "meeting virtually a 20 % increase in load growth over the next decade means building one new substation for every five we have now, one new transmission line for every five and one new power plant for every five."

The Rural Development Utilities Program is currently working with both G&T cooperatives and private developers on wind and biomass projects that will total well over $1 billion in financing. The success of these projects will drive additional investments in the future.

One key to adding additional renewable energy nationwide is the production tax credit. Presently, the availability of the production tax credit and favorable depreciation rates are key to making renewable energy price competitive. Another key has been the enactment of the Clean Renewable Energy Bonds which provide non-profit organizations such as cooperatives the same pricing advantages as the production tax credits available to for-profit developers.

Additionally, the rural electric generation and transmission CEOs announced the formation of a national cooperative dedicated to the development of renewable energy sources. A national effort was deemed necessary because some areas of the country do not have renewable resources and through the national effort, generation cooperatives in the south and southeast that have no wind resources can participate in projects developed in the Great Plains through equity contributions.

While wind and solar renewable energy sources will continue to increase as important components of the energy mix, they should not be considered capacity resources due to intermittency of availability. This has been best stated by the American Wind Energy Association, “It is an energy resource. You take the wind when nature delivers it and rely on other system resources when it is not available.” Other renewable sources such as waste wood can be operated as capacity resources.

10. ENERGY EFFICIENCY

Members of the cooperative part of the electric industry has been recognized nationally as leaders in energy efficiency and demand side management practices. These practices reduce demand and help mitigate the need for new generation capacity. Most distribution cooperatives offer incentives, rebates and other assistance such as free energy audits for residential, commercial and industrial consumers. Many distribution cooperatives also participate in the Electric Programs Energy Conservation Program (ERC) which offers deferral of principal payments on debt. This enables the cooperative to use those funds to assist consumers install energy efficient appliances or other energy saving measures. A very popular and successful effort is the installation of geo-thermal ground loop systems replacing inefficient heating and air conditioning systems. The upfront cost of these systems can be prohibitively expensive for many homeowners, but with the assistance of the deferral program, along with other incentives such as rebates, the cost to the home owner can often be reduced to affordable levels.

Recently, two cooperatives in Alabama and Kentucky and the Hawaii Habitat for Humanity Office were awarded High Energy Cost Grants, administered by the Electric Program, to assist low income homeowners install energy efficiency measures to reduce their energy bills.

A previous grant to the Alabama cooperative proposes to assist 100 very low income home owners repair or replace duct work, install energy efficient appliances, replace inefficient furnaces and central air conditioners with highly efficient heat pumps, install insulation, install energy efficient doors and windows. These efforts not only reduce the energy bills of the home owner, but also reduce the amount of energy the cooperative has to purchase to serve those homes. One example shows the home owner monthly electric bill decreasing from 3979 kWh per month to 2080 kWh per month, a 48% percent reduction.

A recent report filed by the Iowa Association of Electric Cooperatives with the state regulatory body says the Iowa cooperatives estimate $11 million invested in energy efficiency programs last year will return a savings of over $30 million over the life of the various installations. Participants in the program added energy efficient heat pumps, water heaters, air conditioners, compact fluorescent lights and improved weather proofing. According to the report the 37 distribution cooperatives serving 650,000 Iowans increased their investment in energy efficiency by 25%. It is estimated that the energy saved over the life of the installations would be enough to power a city of 85,000 for one year. There is also the benefit of reduced emissions.

11. CLIMATE CHANGE

The intermittency of wind and solar energy means that it cannot be depended on for capacity during peak usage periods. There has to be other energy sources available for those times that wind and solar sources are not available.

This was demonstrated rather dramatically earlier this year in Texas when wind production in west Texas unexpectedly dropped from 1,700 MW to less than one-fourth of that and at the same time late afternoon peak demand rose by over 2,000 MW as people returned home from work. In order to avoid brownouts, the Electric Reliability Council of Texas (ERCOT), the entity that manages the transmission grid in Texas, called interruptible customers (typically large commercial or industrial customers) and asked them to reduce their demand and simultaneously started up natural gas fired peaking facilities to generate additional power to balance supply and demand. Compounding the problem was that some base load units were not generating power due to planned outages for maintenance or other reasons. All of this occurred in a matter of minutes.

Occurrences such as this one lend support to the argument that a balanced approach to limiting carbon emissions, such as that prescribed by the Electric Power Research Institute (EPRI), as well as other studies, is necessary in order to maintain system reliability, sustain economic growth and provide time for the appropriate technologies to be developed. This includes a balanced mix of strategies beginning with energy efficiency and renewable resources, additional nuclear capacity, advanced clean coal generation, carbon capture and storage, plug-in-hybrid vehicles, and distributed energy resources.

The EPRI study points out that carbon capture and storage technology will not be widely available and deployed until after the year 2020.

The EPRI CO2 Reduction Model assumes CO2 emissions are capped at 2010 levels until 2020 and then reduced at 3% annually. The results of the model show that the deployment of the strategies noted above could reduce CO2 emissions to the 1990 levels by 2030.

The Rural Development Electric Program is committed to assisting Basin Electric Cooperative in North Dakota install carbon capture technology at an existing coal fired generation plant. This technology will remove a portion of the carbon dioxide and feed it into an existing CO2 compression and pipeline system owned by Basin from which it will be sold for enhanced oil recovery in North Dakotas and Canada. Smaller portions of CO2 will be taken out of the pipeline and injected into a non-recoverable coal seam and a saline formation to test sequestration capability of those geologic formations. Our goal is to help further the advancement of these technologies.

12. CONCLUSIONS

The system reliability concerns identified in the NERC report, as well as other reports, point out that brownouts are probable unless investment in transmission is increased and simultaneously, energy efficiency efforts and demand side management must be intensified. But it is evident that additional generation sources beginning with renewable resources, but including other base load must be developed. The lead time associated with planning and constructing new base load plants can easily consume 8 to 10 years and the country is already behind the demand curve.

Ensuring reliability of the system while sustaining economic growth and protecting the environment is going to be costly and consumer rates will increase, but the cost of brownouts could be higher due to interruptions of commercial activity. The economy of this country is highly dependent on reliable electricity and that dependence is growing as more of the economy shifts to the service sector and as we move to energy independence. The development of alternative transportation fuels, regardless of the feedstock, will also require significant sources of new generation. Continued development and improvement of new renewable generation technologies, as well as the manufacture of these technologies and the development of technologies to reduce emissions will add more economic and employment opportunities and much of that investment will be in rural America.