1999
Reserve Margin Analyses

August, 1999

FLORIDA RELIABILITY COORDINATING COUNCIL

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Florida Reliability Coordinating Council

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FRCC
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Table of Contents

Executive Summary

The Florida Reliability Coordinating Council (FRCC) conducts a review of the reliability of the Region on an annual basis in compliance with North American Electric Reliability Council (NERC) Standards. The FRCC analyzes its members' load and resources plans and submits its findings to the Florida Public Service Commission. For 1999, the FRCC conducted both reserve margin and loss-of-load-probability (LOLP) analyses of the load and resources projected for Peninsular Florida's utilities. However, because the results of the 1999 LOLP work were very similar to the results of the 1998 LOLP work, i.e., LOLP values for the peninsula are projected to be significantly lower than the generally accepted 0.1 day/year standard, the FRCC chose to primarily focus its 1999 work on analyzing the projected reserve margin levels for the peninsula. A description of the work carried out as part of this reserve margin analysis, plus the results of the analysis, are presented in this document.

The reserve margin analyses used projections of resources and demands which are found in the FRCC's 1999 Regional Load & Resource Plan, submitted to the Florida Public Service Commission on July 1, 1999. The FRCC analyses were directed towards determining whether the peninsula's composite reserve margin met the FRCC's 15% reserve margin criterion and towards confirming the continued adequacy of that standard. The FRCC used as its basis reserve margin analyses it had undertaken in 1998, considered the availability of additional data, and made improvements in its analysis techniques where warranted.

Based on this analysis of projected reserve margins for the peninsula, plus the results of the 1999 LOLP work, it is clear that: (1) the FRCC's current projected reserve margin levels do meet and/or exceed the 15% standard; and (2) the FRCC concludes that the existing and planned resources for the peninsula will reliably meet the expected needs of the peninsula's electricity consumers over the 1999 through 2008 study period. In addition, the analysis confirmed that the FRCC's 15% reserve margin criterion continues to be suitable for planning purposes.

Finally, due to the fact that most of the planned generating resource additions for the peninsula for the 1999 through 2008 time period are projected to burn natural gas, a letter from the Florida Gas Transmission (FGT) Company has been included (as Exhibit I) in this document to present the FGT's most current view of natural gas availability for the peninsula during this time frame.

I. Introduction

In September 1997, the North American Electric Reliability Council (NERC) adopted a new set of NERC Planning Standards. The NERC Planning Standards include a requirement to review and assess the overall reliability of the (NERC) Regions' electric systems to ensure that the Regions conform to their own Regional planning criteria and to the NERC Planning Standards. In 1998, the Florida Reliability Coordinating Council (FRCC) formally adopted a generation resource adequacy standard for reserve capacity. It is as follows: "The FRCC generation resource adequacy standard for reserve capacity shall be a 15% regional reserve margin based on firm load. Each year the FRCC composite Ten Year Load and Resource Plan shall be assessed to ensure that this resource adequacy standard of 15% regional reserve margin is maintained over the peak periods. Any peak period which does not meet this regional reserve margin standard shall be thoroughly assessed by the RAG (Reliability Assessment Group), and such assessment shall be forwarded to the FRCC Executive Board and to the Florida Public Service Commission."

The FRCC conducted analyses of the projected composite reserve margins for peninsular Florida during its 1999 work. A technical sub-group of the FRCC, known as the Resource Working Group (RWG), focused on two objectives. The first objective was to determine if the peninsula's composite reserve margin met the FRCC's 15% reserve margin generation resource adequacy standard. The second objective was to take a look at whether this 15% standard still appeared to be adequate. Supplemental work on loss-of-load (LOLP) was also performed and determined not to be a driving factor in reserve adequacy.

In regard to the first objective, the FRCC's work clearly showed that the composite reserve margin for the peninsula met the 15% standard. This fact has already been presented in the FRCC's 1999 Regional Load & Resource Plan which was submitted to the Florida Public Service Commission (FPSC) on July 1, 1999. Consequently, this document focuses on the second objective: analyzing whether the 15% standard still appears to be adequate. These analyses were based on similar reserve margin analyses which were performed in the FRCC's 1998 Reliability Assessment. The results of the 1998 analyses supported both the 15% standard and the 1998 projected reserve margin levels for the peninsula.

II. Methodology Used in the Analyses

A. The Reserve Margin Concept

When calculating a utility's reserve margin, five separate component values are used:

1) Amount of capacity (MW) available at the peak hour from the utility's own generating units.
2) Amount of capacity (MW) available at the peak hour from qualifying facilities (QFs) with which the utility has a firm capacity contract.
3) Amount of capacity (MW) available at the peak hour resulting from the utility's firm import capacity contracts.
4) Peak hour load served by the utility (MW) before the effects of any demand side management programs (DSM) sponsored by the utility. (DSM encompasses incremental conservation, load management, and interruptible rate programs.)
5) Capability (MW) of the utility's DSM programs at the peak hour.

When a utility projects a reserve margin, it is forecasting or projecting what each of these five component values will be at a peak hour in a given year in the future. These component values are then used to calculate reserve margin using the following formula:

$$\text{Reserve margin (\%)} = \frac{\text{(Total firm capacity} - \text{Firm seasonal peak load)}}{\text{(Firm seasonal peak load)}} * 100$$

Where: Total firm capacity = Utility generation capacity + firm QF capacity + firm import capacity

and Firm seasonal peak load = Peak load served by the utility minus DSM MW.

Utilities maintain reserves (i.e., capacity resources over and above the exact MW amount that is projected to be needed for a given year) because they recognize that it is impossible to exactly predict the load which customers may require in the future, to know exactly when a generating unit may break and have to be taken out of service for repairs, etc. A utility maintains reserves in recognition of this inability to perfectly forecast all of these factors and to thus ensure that adequate generating resources will exist to cover uncertainties and allow the utility to reliably provide electric service.

B. Deciding What Reserve Margin Level to Maintain

The utility industry "standard" for reserve margin levels in the United States has been approximately 15% for some time. Years of operating experience have shown utilities that a 15% level of reserves "works". In other words, this level of reserves enables utilities to reliably maintain the ability to provide electricity service to its customers while keeping electricity rates at a reasonable level. Providing higher levels of reserves means providing higher levels of firm capacity and/or of DSM. This results in a utility either purchasing more firm capacity through purchase contracts, building new generating units, and/or implementing more DSM, all of which have an impact on electricity rates.

For its 1999 work of assessing the continued suitability of its 15% reserve margin standard, the FRCC chose an approach which combines the current projected reserve margins for the peninsula with a look at historical performance levels of the utilities.

C. The FRCC's Approach to Analyzing Reserve Margin Levels

It should be understood that the FRCC's approach to examining reserve margins is not an approach that necessarily determines an appropriate reserve margin level; rather it is an approach which can be used to test a particular reserve level against historical performance levels as well as against certain contingencies. The information produced by this analysis can then be used in combination with appropriate engineering / economic judgement and experience to adjust, if necessary, a predetermined reserve margin level.

The approach utilized by the FRCC is based on examining how accurately the utilities have been able to project the component values of a reserve margin calculation. In order to calculate this level of accuracy, the utilities' most recent projections are compared to the actual values for these years. The results of this comparison are used to develop "certainty factors" for each component of a reserve margin calculation. Then these "certainty factors" are applied to the current projected reserve margins for the peninsula in order to determine the effect of these variables on both a 15% reserve margin criterion and on the current projected reserve margins.

The following four steps are used in these analyses:

1) **For each utility, the projection accuracy (i.e., a Certainty Factor) for each component of a reserve margin calculation is separately calculated:**

   a) Utility installed generation, firm QF capacity, and firm import capacity (i.e., the first three component values identified in Section II.A. above): From previous years' reserve margin projections by each utility (such as those reported in Ten Year Site Plans, etc.), the projected values for utility installed generation, firm QF capacity, and net imports which are all expected to be available at the seasonal peak hour were extracted. These values are the utilities' historical projections of what they expected to have available.

   Then, from each utility's database, the actual amount of installed generation, firm QF capacity, and net imports which were available for each of these seasonal peak hours is extracted.

   A historical "Certainty Factor" for each of these capacity components of reserve margin is then developed by dividing the actual value for a given year by the historical projection for that year. For example, assume that the original projection for a given year called for 100 MW of installed utility generation to be available on the Summer peak hour, but only 94 MW were actually available that peak hour. In this case, a "Certainty Factor" of 94% (94 actual MW divided by 100 projected MW) for this component of reserve margin would be calculated.

Since utilities do not plan to take their generating units out for planned maintenance during the time around seasonal peak hours, the 6% by which the utility in the example "missed" its projection is most likely due to a forced outage. A utility may experience either an abnormally small or an abnormally large amount of forced outages on the peak hour of any one year. Consequently, it is advisable to look at more than one year's data when developing a Certainty Factor in order to determine what level of certainty is really historically representative for the utility. For its 1999 analyses, the FRCC used comparisons of projections versus actuals for the last 6 years in developing Certainty Factors for installed generation, firm QF capacity, and firm import capacity. The Certainty Factors for each were arithmetic averages of the 6 years' results of comparing projections versus actuals.

b) <u>Load forecasts (i.e., the fourth component value identified in Section II.A. above):</u> Certainty factors for load forecasts were also developed in a similar fashion to the approach explained above for developing certainty factors for the three capacity components of reserve margins calculations. However, unlike the averaging approach used to calculate <u>one</u> overall Certainty Factor for each of the capacity components, a separate Certainty Factor was developed for forecasts looking ahead 2 years, another Certainty Factor was developed for forecasts looking ahead 3 years, etc. This is based on the premise that a projection of load only 2 years out <u>should be</u> more accurate than a projection of load made 3 years (or more) out. In other words, the further out one tries to forecast the less accurate one can expect the forecast to be. Therefore, the further out the forecast is, the greater the expected deviation from 1.00 in the associated Certainty Factor.

Consequently, a series of Certainty Factors was developed for the load forecast component of reserve margin calculations.

c) DSM capability (i.e., the fifth component value identified in Section II.A. above): When considering the total projected DSM capability for peninsular Florida, it is apparent that the majority of this capability is made up of the utilities' load management programs. As a result, the FRCC's approach focused on developing a Certainty Factor for load management. This was also based upon historical information. Each utility which offers load management reexamined both their confidence in being able to sign up and retain the required number of load management program participants to achieve the projected load management MW reduction values, as well as their confidence in the kw reduction/participant value they apply to the projected number of participants. (These reduction values are generally derived from past field monitoring and/or engineering estimates.) By combining these two confidence values, a load management Certainty Factor for each utility was developed.

2) These individual utility Certainty Factors are combined into a composite, peninsular Certainty Factor for each component of the reserve margin calculation:

For the three capacity components, and the load forecast component, this was done by first adding up all of the individual utilities' projected values to get a projected total. Then the individual utilities' actual values were added up to get an actual total. Dividing the actual total by the projected total results in a composite peninsular Certainty Factor for each of these four reserve margin components.

The load management Certainty Factors developed by each utility for the FRCC's 1999 work were then combined to form a composite value. Each utility's total load management capability was divided by the total sum of all utilities' load management capability to derive a "weighting" of each utility's contribution to the peninsula's total load management capability. Then each utility's individual load management Certainty Factor was multiplied by this weighting factor and the resulting weighted Certainty Factors from each utility were added together to form the composite load management Certainty Factor for the peninsula.

3) A "coincidence factor" for the composite load forecast was developed:

The FRCC's current projection of reserve margins, as shown in the FRCC's 1999 Regional Load & Resource Plan, simply takes all of the components of a reserve margin calculation (utility installed generation, load forecast, etc.) for each utility and adds the components together. This approach is fine for four of the components: utility installed generation, firm QF capacity, firm import capacity, and load management capability, since all of these components for individual utilities can, and frequently do, operate at the same time.

However, this approach tends to overstate the forecasted load which the peninsula will experience. This is because the various utilities tend to peak at different times of the day and/or days of the month. Consequently, a more accurate way to project a composite, total forecasted load for the peninsula is to address the fact that this load will be somewhat less than the sum of each utility's individual load. The FRCC did not address this in its 1998 analyses of the 15% standard. However, the FRCC decided to make this improvement to its analysis approach in its 1999 work. The different timing of individual utility loads was addressed through the application of a non-coincidence adjustment factor which accounts, through the use of historical data, for the timing of individual utility peaks. For its 1999 work, non-coincidence adjustment factors of 98.4% and 98.3% were used for Summer reserve margin and Winter reserve margin calculations, respectively. The application of these non-coincidence adjustment factors serves to properly lower the composite total forecasted load for the peninsula in its reserve margin calculations. This approach is consistent with the way that individual utilities plan their systems since they project their customers' peak loads on a coincident basis. Thus, when projecting peak loads for utilities in the aggregate, it is appropriate to also do so on a coincident basis.

4) **The composite certainty and non-coincidence adjustment factors are applied to the current projection of peninsula reserve margins:**

The current projection of reserve margins for the peninsula (as shown in the FRCC's 1999 Regional Load & Resource Plan) is used as the starting point for applying the composite Certainty Factors and non-coincidence adjustment factors described above. The basic approach is to first apply the non-coincidence adjustment factor to more accurately reflect the total load for the peninsula. This results in a revised reserve margin projection. Then the individual Certainty Factors are applied, one at a time, to this revised reserve margin projection which results in a series of revised reserve margin projections. For example, assume that the current projection of utility installed generation capacity is 30,000 MW for a given year and the calculated Certainty Factor is 0.90 for this component. The resulting revised utility installed generation capacity value would now be 27,000 MW (30,000 MW x 0.90 = 27,000 MW). Applying this revised component in the reserve margin calculation would yield a revised reserve margin.

Once all of these factors have been applied, the final revised reserve margin projection is then compared to the original projection. In almost all cases, the final revised reserve margin projection is lower than the original projection of reserve margins. This is because the original reserve margin projection basically assumes that the values for all components of the reserve margin calculation are known with 100% certainty. (The application of the non-coincidence adjustment factor first results in a lowering of the forecasted load and a corresponding increase in the revised reserve margin. However, the subsequent application of each of the various Certainty Factors generally serves to lower the values of each of the components, thus considerably lowering the revised reserve margin.) A common outcome of this method is for an original reserve margin projection in the 15% - to- 20% range to be revised down to a final value in the 1% - to - 5% range after all of the factors have been applied. The meaning of such an outcome is discussed below.

The difference between the original projection and the final revised projection represents the reserve margin level that could be "needed" based on the utilities' most recent projected versus actual values.

For example, assume that the FRCC's original reserve margin projection for the peninsula is 16% for a given year. Now assume that after each of the factors have been applied, the original projected 16% reserve margin level drops to a revised level of 2%. The difference of 16% - 2% = 14% indicates that a 14% reserve margin level could, based on the utilities' most recent ability to project loads and have resources available to meet them, be sufficient to maintain reliable electric service during the peak hours of that year.

This conclusion is drawn by the fact that if the original reserve margin projection had been 14%, the application of the factors would have resulted in a final revised reserve margin of 0%; i.e., the peninsula's resources would have been exactly equal to the peninsula's load after accounting for the uncertainties of all of the components. The 2% reserve margin value that is "left over" in this example, would be an additional reserve margin "cushion" over what the "needed" reserve margin is. Consequently, electric service during the peak hour should be maintained.

Also in this example, note that both the FRCC's 15% reserve margin planning criterion and the peninsula's projected 16% reserve margin could be deemed sufficient to maintain reliable electric service.

On the other hand, assume again that the FRCC's original projected reserve margin for a given year was 16%, but now assume that the revised reserve margin level drops to –1% after all of the certainty factors have been applied. In this example, the difference of 16% - (-1%) = 17% shows that a 17% reserve margin level could be "needed" to meet loads at seasonal peaks. In this example, the peninsular Florida utilities would want to examine whether any actions were necessary to correct or minimize the associated uncertainties to maintain reliable electric service at reasonable cost.

D. The FRCC's 1998 and 1999 Analyses

As mentioned above, the FRCC began using this basic approach to analyze the suitability of its current 15% reserve margin planning criterion in its 1998 work. In that effort, two decisions regarding the data to be used were made:

1) The actual and projected values for the three capacity components (utility installed generation, firm QF, & firm imports) would be taken from 1993 through 1997.
2) The projected values for load forecasts would start with the 1988 forecast projections for future years.

These decisions were largely based on the recognition that utility methodologies and practices tend to change over time as new methods are developed, priorities change, etc. Therefore, it was important not to go back in time too far to extract data to work with. In 1998, it was felt that the (then) most recent 5 years worth of data covering the period of 1993 through 1997 was sufficient to address the actual-versus-projected performance of utility generators, firm QF capacity, and firm imports at peak hours.

However, since it may take approximately 3-to-6 years to bring new power plants in-service from the time a need to add capacity is recognized, it was necessary to look at load forecasts going further back in time than 1993 in order to capture as many 3-to-6 years ahead forecasts as possible, as long as these forecasts were deemed applicable.

The decision was made that forecasts from 1988-forward were applicable. The selection of the year 1988 as the starting point for forecast analyses was made primarily due to the fact that the current load forecasting methodology for the peninsula's largest utility, FPL, were first in place in 1988. The selection of a 1988 starting point also enabled the FRCC to look at forecasts of future load as much as 9 years out.

For its 1999 work, another year (1998) of actual load, generation, etc. was available for use in the analysis. The FRCC faced the question of whether to drop the oldest year of data from its previous year's work and replace it with 1998 data, or to add this additional year's data to its previously developed database without any corresponding omission of older data. The decision was made to do the latter for the 1999 FRCC work but with the recognition that, in future years, it may be appropriate to drop off older data.

For its 1999 work, new Load Management Certainty Factors were developed. These factors were not directly based on the factors used in the 1998 work. Instead, each utility was asked to place a new, "from scratch" certainty value on their projected load management capabilities using any new monitoring data available and their 1998 experience with load management.

In addition to these, there were two changes in the FRCC's 1999 analysis approach compared to the analysis approach used in its 1998 work. Both changes represent needed improvements to the approach used in 1998 which were recognized while reviewing the 1998 work. The first of these, the inclusion of a non-coincidence adjustment factor to more accurately compile a composite forecasted load for the peninsula, has already been discussed. The second improvement was to drop the 1993 Winter values for utility installed generation from the calculation of an installed generation Certainty Factor for Winter.

In the Winter of 1993, the Winter seasonal peak load actually occurred very late (in March). This peak occurred after various utilities had assumed that the peak load for that Winter had already been experienced. Consequently, these utilities allowed generating units to come off-line for maintenance that had been planned for several weeks later in order to be better prepared for the upcoming Summer loads. These units were thus not available when this unexpectedly late Winter load was experienced. Since the installed generation Certainty Factor is designed to test "breakage" (or forced outages) of units that are expected to be in-service during all peak periods, it was felt that continuing to include the effects of this "unforced" maintenance experienced in 1993 was incorrect. Therefore, the actual and projected values for Winter 1993 were discarded in the FRCC's 1999 analyses (except the analysis of one scenario which was included solely to provide a comparison to the 1998 work).

III. Results of the 1999 FRCC Analyses

A. Description of the Cases Analyzed

The FRCC's 1999 reserve margin analysis work ultimately resulted in an examination of five cases. These cases are described in Table 1.

The Base Case is the case which the FRCC believes is the most meaningful case analyzed. It was constructed by adding the actual and projected 1998 values to the database used in last year's analyses. In other words, one more year of data has been added to the database and the expanded database is then used to develop new Certainty Factors for: utility installed generation, firm QF's, firm imports, and load forecast. The 1999 Load Management Certainty Factors also replaced the factors used in the 1998 work. Then the effects of two improvements (which have been previously discussed) to the analysis approach were incorporated: the inclusion of a non-coincidence adjustment factor for load forecasts and the removal of the 1993 Winter data for utility installed generation.

Table 1

Description of Cases in FRCC's 1999 Reserve Margin Analysis

Name of Case	Description of Cases
Base Case	Most meaningful case. Contains 1998 actuals and projections added to last year's database, the new 1999 Load Management Certainty Factor, and 2 improvements to last year's approach: (1) addition of a non-coincidence adjustment factor for load forecasts, and (2) removal of Winter 1993 actual and projected data for utility installed generation.
Scenario 1	For comparison with last year's work only. Contains 1998 actuals added to last year's database, and the new 1999 Load Management Certainty Factor, with no changes/improvements to last year's approach.
Scenario 2	Base Case with worst value for utility installed generation availability applied every year.
Scenario 3	Base Case with worst values for load forecast accuracy applied to each corresponding forecast year (i.e., worst value for 5-year out forecast applied to current 5-year out forecast, etc.).
Scenario 4	Base Case with combination of worst values for utility installed generation availability and load forecast accuracy applied.

The FRCC believes the Base Case is the most meaningful case because of these two improvements to the approach and because of the fact that it captures a truly representative set of values (i.e., a range of values including accurate to not-so-accurate projections) of the peninsular utilities' recent unit and firm purchase availability, load forecast accuracy, and the most current view of load management capability.

In addition to the Base Case analysis, four other scenarios were analyzed. Scenario 1 is a "stand alone" analysis while Scenarios 2, 3, and 4 use the Base Case as a starting point. Scenario 1 is offered solely to provide a point-of-reference comparison to last year's FRCC work. In Scenario 1, neither of the two improvements to last year's analysis approach have been included. The only change to last year's results is the inclusion of the 1998 actual and projected values to last year's database, which result in the development of new Certainty Factors for four of the five components, and the use of the new-for-1999 Load Management Certainty Factor

Scenarios 2, 3, and 4 are best characterized as "worst case every year" analyses which focus on the two biggest "drivers" of the amount of reserve margin "needed": utility installed generation availability at peak hours and load forecast accuracy.

Scenario 2 returns to the Base Case and uses its results as a starting point. Then the worst annual value for the availability of utility installed generation at the peak hour is extracted and inserted as the utility installed generation Certainty Factor for all years. This "worst case every year" scenario thus assumes that unit availability at the peak hour degrades to the worst value experienced during the last 6 years and remains at this low level with no remedial action by the utilities to improve the situation.

Scenario 3 also uses the Base Case results as a starting point. In this scenario, the worst values for load forecast accuracy for 2-years out, 3-years out, etc., are extracted and inserted for the corresponding load forecast Certainty Factor. For example, assume that the worst case of load forecast accuracy for a 3-years out forecast was 12% too low while the multi-year average for a 3-year out forecast was 5% low. In Scenario 3, a "worst case" Certainty Factor of 1.12 is substituted in place of the 1.05 Certainty Factor value for a 3-year out forecast used in the Base Case. Similar Certainty Factor substitutions occur for all other "years out" of the load forecast. This "worst case every year" scenario assumes that all of the worst levels of load forecast accuracy are now applied to the current peninsular composite forecast and that the utilities take no remedial action to improve the situation. Note that the extraction of the worst accuracy level for each year from forecasts done over multiple years is an even more damaging (and a less probable) assumption than the worst case utility installed generation availability assumption made in Scenario 2.

Finally, Scenario 4 once again returns to the Base Case but now combines the "worst case" Certainty Factors for utility installed generation availability and load forecast accuracy from Scenarios 2 and 3. This most extreme "worst case every year" scenario basically assumes that the utilities simultaneously allow unit availability at peak hours, and the accuracy of their load forecasts, to significantly degrade without taking remedial action. This scenario should be considered very unlikely.

B. Results of the Analyses

The results of the FRCC's 1999 reserve margin analyses are presented in Tables 2 through 5. Tables 2 and 3 focus on the results as they pertain to Summer reserve margins while the results presented in Tables 4 and 5 pertain to Winter reserve margins.

These tables first present the FRCC's reserve margin planning criterion (15%) and then present the FRCC's current projections of annual reserve margins for the peninsula in the columns marked "FRCC's Current Projected Reserve Margin (%)". The values in these columns have been previously reported in the FRCC's 1999 Regional Load & Resource Plan.

Following these columns come the actual results of the analyses: the "needed" level of reserve margins as calculated for the Base Case and for Scenarios 1 through 4. In addition, two questions are addressed in Tables 3 and 5. The first of these questions is "Does the FRCC's 15% minimum reserve margin planning criterion meet or exceed the calculated level of "needed" reserve margins for a given case?" If the answer is "Yes", then the 15% minimum criterion can be considered adequate to maintain reliable electric service during peak hours. The second question is "Do the FRCC's current projected reserve margins meet or exceed the calculated level of "needed" reserve margins for a given case?" If the answer is "Yes", then the peninsula's projected reserve margins can be considered adequate to maintain reliable electric service during peak hours.

Since the peninsula's projected reserve margins are typically greater than the planning criterion of a minimum of 15%, a possible outcome is one in which the "needed" reserve margin is greater than 15% but less than or equal to the projected reserve margins. With such an outcome, the projected reserve margins would still be considered adequate.

Another possible outcome is one in which the "needed" reserve margin level is greater than both the minimum 15% criterion and the peninsula's projected reserve margin for one or more years. Taken at face value, one might interpret this to indicate that neither the FRCC's planning criterion nor their projected reserve margins are adequate. However, this is not necessarily correct. Other factors need to be taken into consideration before reaching such a conclusion.

First, when (for what year) does such a result appear? If this result appears for seven or more years out in the future, the utilities have sufficient time to adjust their capacity plans accordingly. Conversely, if such a result occurs prior to three years out, relatively little from a utility capacity planning perspective can be done due to the short lead time available. Consequently, the key time frame which this analysis approach focuses on is the 3rd through the 6th year out period.

Second, how likely is it that the assumptions behind the analysis case in question will come to pass? If the answer is that the assumptions are not likely, then the potential concern is minimized or eliminated. Only if the assumptions are considered likely, and if the time frame in question is reasonably close at hand (i.e., in the 3-to-6 years out range), is it prudent to be concerned with the results of this particular analysis.

Finally, it is important to recognize that utilities have a significant amount of additional MW's available to them in the form of operational measures (e.g. public appeals, voltage reductions, load control "scram", etc.) that are not included in these reserve margin calculations but which are already in place. These measures offer a significant safety factor at little or no cost to customers compared to construction or purchase alternatives.

(1) Results Regarding Summer Reserve Margins

The results of the FRCC's 1999 reserve margin analyses in regard to Summer reserve margins are summarized in Tables 2 and 3. Table 2 presents the 15% reserve margin standard, the current projection of the peninsular Summer reserve margins, and the "needed" Summer reserve margin levels from the analysis of the Base Case.

Table 2

Results of 1999 FRCC Analysis of Summer Reserve Margins

Year	FRCC's Planning Criterion	FRCC's Current Projected Reserve Margin (%)	"Needed" Reserve Margin (%) for: Base Case
1999	15	17	6
2000	15	16	8
2001	15	18	9
2002	15	20	10
2003	15	20	11
2004	15	19	10
2005	15	18	12
2006	15	17	13
2007	15	18	13
2008	15	17	13

As shown in Table 2, the results for the FRCC's Base Case show that the "needed" Summer reserve margin is 13% or less each year. This result indicates that both the FRCC's reserve margin planning criterion of a 15% minimum level, and the FRCC's higher-than-15% projected reserve margins for each year, are more than adequate to maintain system reliability during Summer peak hours.

Table 3 presents an expanded version of Table 2. In addition to the information presented in Table 2, the results of the Summer reserve margin analyses of Scenarios 1 through 4, plus a summary of comparisons of the results to the 15% standard and to the projected reserve margin, are added.

Table 3

Results of 1999 FRCC Analysis of Summer Reserve Margins (w/Scenarios)

			"Needed" Reserve Margin (%) for :				
Year	FRCC's Reserve Margin (%) Planning Criterion	FRCC's Current Projected Reserve Margin (%)	Base Case	Scenario 1	Scenario 2	Scenario 3	Scenario 4
1999	15	17	6	8	9	6	9
2000	15	16	8	9	11	12	15
2001	15	18	9	11	12	13	16
2002	15	20	10	12	13	12	15
2003	15	20	11	13	14	18	20
2004	15	19	10	12	13	16	19
2005	15	18	12	14	15	18	20
2006	15	17	13	15	16	18	21
2007	15	18	13	15	16	18	21
2008	15	17	13	15	16	18	21

	Base Case	Scenario 1	Scenario 2	Scenario 3	Scenario 4
(1) Does 15% planning criterion meet/ exceed "needed" reserve margins?	Yes	Yes	No for last 3 yrs	No for last 6 yrs	No for 7 of 10 yrs
(2) Do current projected reserve margins meet/exceed "needed" reserve margins?	Yes	Yes	Yes	No for 8th& 10th yr.	No for last 4 yrs

The results for Scenario 1 are similar to those for the Base Case. In this scenario, the projected "needed" reserve margin is 1-to-2% higher than in the Base Case (due to Scenario 1's omission of the non-coincidence adjustment factor for load forecasts). Nevertheless, the resulting "needed" reserve margin is 15% or lower each year, which again means that both the planning reserve margin of a 15% minimum level and the higher-than-15% projected reserve margins are adequate for maintaining system reliability.

Only in the three "worst case every year" scenarios do the results change at all. In Scenario 2 (which is the Base Case, but with the worst case of utility installed generation availability at the peak hour assumed to occur every year), the results show that the 15% minimum reserve margin planning criterion is adequate for all except the 8th, 9th, and 10th years of the projection. However, the FRCC's projected reserve margins for all years still satisfy the "needed" reserve margin levels for this scenario.

In Scenario 3 (which is the Base Case but with the worst cases of load forecast accuracy assumed to occur every year), the 15% minimum reserve margin planning criterion could be insufficient for the last 6 years. However, the FRCC's projected reserve margins still satisfy the "needed" reserve margins in all years except the 8th and 10th years of the projection.

Finally, in Scenario 4 (which is a combination of Scenarios 2 and 3 in which the Base Case is modified to include both the worst cases of utility generation availability and load forecast accuracy every year), the 15% minimum reserve margin planning criterion could be insufficient for 7 of the 10 years and the FRCC's projected reserve margins could be insufficient for the last 4 years of the projection period (i.e., the 7th, 8th, 9th, and 10th years). However, even in this very extreme scenario, the FRCC's projected reserve margins meet the "needed" reserve margin levels for the key 3-to-6 years out time period.

Conclusion Regarding Summer Reserve Margin Analyses:

The FRCC concludes from this analysis of Summer reserve margins that its reserve margin planning criterion of a 15% minimum level, and its projected annual reserve margin levels, are adequate for maintaining reliable electric service during Summer peak hours for years 1999 through 2008.

The minimum 15% reserve margin planning criterion, and the FRCC's projection of annual reserve margins, meet or exceed the "needed" reserve margin levels calculated in both the Base Case and Scenario 1. Although the results from the remaining three "worst case every year" scenarios show that the minimum 15% reserve margin planning criterion could be insufficient for some of the years, it is unrealistic to believe that utility generation availability and load forecasting practices would remain unchanged if a trend of occurrences such as those depicted in these scenarios were to appear.

Furthermore, the FRCC's projected annual reserve margins are sufficient to "cover" all years in Scenario 2, are sufficient for all but the 8^{th} and 10^{th} years in Scenario 3, and are sufficient for all but the 7^{th} through 10^{th} years in Scenario 4. The fact that all years are "covered" even in these "worst case every year" analysis until, at the earliest, 7 years out means that the utilities have more than enough time to alter their capacity addition plans if circumstances reflected in these scenarios begin to emerge. In addition, as previously mentioned, there are operational measures available which are not included in reserve margin calculations that would alleviate the effects of these uncertainties were they to occur.

(2) Results Regarding Winter Reserve Margins

The results of the FRCC's 1999 reserve margin analyses in regard to Winter reserve margins are summarized in Table 4 and 5. Tables 4 and 5 are identical in format to Tables 2 and 3, respectively. Table 4 presents the 15% reserve margin standard, the current projection of peninsular Winter reserve margins, and the "needed" Winter reserve margin levels from the analysis of the Base Case.

Table 4

Results of 1999 FRCC Analysis of Winter Reserve Margins

Year	FRCC's Reserve Margin (%) Planning Criterion	FRCC's Current Projected Reserve Margin (%)	"Needed" Reserve Margin (%) for: Base Case
1999/00	15	16	5
2000/01	15	18	-2
2001/02	15	20	-2
2002/03	15	21	-2
2003/04	15	19	-3
2004/05	15	19	-3
2005/06	15	18	0
2006/07	15	18	-1
2007/08	15	18	-1
2008/09	15	15	-1

As shown in Table 4, the results from the Base Case show that the "needed" Winter reserve margin are not only significantly less than 15% each year, they are negative for most years. This is primarily due to the fact that forecasted very cold temperatures do <u>not</u> occur in Florida every year, but that the FRCC's projected reserve margins for the peninsula <u>do</u> assume that they occur each year. Consequently, the Winter load forecast Certainty Factors for each year (approximately 94%) in the Base Case are substantially less than the corresponding Summer load forecast Certainty Factors each year (approximately 104%). This results in the projected load being lowered to the point in the Base Case where the "needed" reserve margin is negative for most years. Obviously, both the 15% minimum reserve margin planning criterion and the FRCC's projected annual reserve margins are more than adequate to maintain system reliability during Winter peak hours under the assumptions analyzed.

Table 5 presents an expanded version of Table 4. In addition to the information presented in Table 4, the results of the Winter reserve margin analyses of Scenarios 1 through 4, plus a summary of comparisons of the results to the 15% standard and to the projected reserve margins, are also presented.

Table 5

Results of 1999 FRCC Analysis of Winter Reserve Margins (w/Scenarios)

Year	FRCC's Reserve Margin (%) Planning Criterion	FRCC's Current Projected Reserve Margin (%)	"Needed" Reserve Margin (%) for: Base Case	Scenario 1	Scenario 2	Scenario 3	Scenario 4
1999/00	15	16	5	9	10	5	10
2000/01	15	18	-2	1	3	20	24
2001/02	15	20	-2	1	2	20	24
2002/03	15	21	-2	1	3	18	22
2003/04	15	19	-3	0	2	15	19
2004/05	15	19	-3	1	2	15	19
2005/06	15	18	0	4	5	16	20
2006/07	15	18	-1	2	4	18	22
2007/08	15	18	-1	2	4	18	22
2008/09	15	15	-1	2	4	18	22

	Base Case	Scenario 1	Scenario 2	Scenario 3	Scenario 4
(1) Does 15% planning criterion meet/ exceed "needed" reserve margins?	Yes	Yes	Yes	No for 7 of 10 yrs	No for 9 of 10 yrs
(2) Do current projected reserve margins meet/exceed "needed" reserve margins?	Yes	Yes	Yes	No for 2nd & 10th yrs	No for 7 of 10 yrs

The results for Scenario 1 are very similar to those for the Base Case (although the values are not negative). This same result is also reflected in the first of the "worst case every year" analyses, Scenario 2, in which the worst case utility generation availability at peak hour is assumed to take place every year.

Only in the two "worst case every year" scenarios (Scenarios 3 and 4) in which the worst case of load forecast accuracy is assumed to occur every year do these results change. Both of these cases assume that very cold temperatures <u>will</u> occur every year. In Scenario 3, the minimum 15% reserve margin planning criterion could be insufficient for 7 of the 10 years. However, the FRCC's projected annual reserve margins would still be adequate for all but 2 of the 10 years (i.e., the 2^{nd} and 10^{th} years). This means that for the key period, years 3-to-6, are still "covered" by the FRCC's projected reserve margin. Finally, in the most extreme scenario (Scenario 4) in which both the worst cases of load forecast accuracy and utility installed generation availability are assumed, the results indicate that the minimum 15% reserve margin planning criterion could be insufficient for 9 of the 10 years and the FRCC's projected annual reserve margins could be insufficient for 7 of the 10 years.

<u>Conclusions Regarding Winter Reserve Margin Analyses:</u>

The FRCC concludes from this analysis of Winter reserve margin that its reserve margin planning criterion of a 15% minimum level, and its projected annual reserve margin levels, are adequate for maintaining reliable electric service during Winter peak hours.

The minimum 15% reserve margin planning criterion, and the FRCC's projection of annual reserve margins, meet or exceed the "needed" reserve margin levels calculated in the Base Case, in Scenario 1, and in one of the "worst case every year" cases, Scenario 2.

Even though the results from the "worst load forecast accuracy every year" Scenario 3, indicate that the minimum 15% reserve margin planning criterion could be insufficient, the FRCC's projected annual reserve margins would still "cover" these circumstances for all but 2 years. One of those years is in the last (10^{th}) year of the projection and is, therefore, subject to at least several years of changed assumptions and new projections before that year is close enough to the present to be of real concern from a planning perspective. The other year for which the FRCC's projected reserve margins could be deemed insufficient in this scenario (i.e., the 2^{nd} year) is obviously much closer. In fact, it is too close to fall into the 3^{rd} through the 6^{th} year time frame for which this analysis approach is really designed. Furthermore, the analysis does not take into account either the fact that very high Winter peaks do not occur every year or utilities' operational capabilities (load control program scram operation, etc.) which would effectively increase utility reserves.

The key point of the results of this scenario is that for the key years (i.e., the 3^{rd} through the 6^{th} years) for which new capacity could realistically be added if a need was identified, no additional capacity over and above what is shown in the FRCC's projected annual reserve margins is needed even assuming, unlikely as it may be, that the worst case load forecast accuracy occurs for each of these years.

Finally, the results from Scenario 4 are driven by the very unlikely assumption that the worst case utility generation availability and the load forecast accuracy occur in combination each year, and that the utilities do not alter their forecasting or power plant maintenance processes (or their capacity plans) in response to these circumstances. This fact, plus the facts that very cold winter temperatures do not occur every year and the utilities' operational capabilities are again not accounted for in the analysis, serve to significantly discount the significance that should be applied to the results of this most extreme of the "worst case" scenarios.

IV. Summary

The FRCC's 1999 work regarding reserve margins for the peninsula had two objectives: (1) to determine if the current projected reserve margin for the peninsula met the FRCC's 15% reserve margin generation resource adequacy standard; and, (2) to take a look at whether this 15% standard still appeared to be adequate.

In regard to the first objective, the FRCC's current projected reserve margin levels do meet and/or exceed the 15% standard. This fact is demonstrated in the FRCC's 1999 Regional Load & Resource Plan.

As for the second objective, an analysis of the continued suitability of the 15% standard was carried out. The results of that analysis showed that this minimum 15% criterion continues to appear suitable for planning purposes based on an examination of past projected-versus-actual performance levels.

EXHIBIT I

Florida Gas Transmission Company

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July 8, 1999

Ken Wiley
Florida Reliability Coordinating Council
405 Reo Street
Tampa, FL 33609-1094

Dear Mr. Wiley:

Florida Gas Transmission Company is pleased to provide the following information regarding the availability and deliverability of natural gas for electric generation requirements for the period 1999 through 2008.

Our response is provided in five parts: (a) a discussion of the projected market and firm transportation capacity for the year 2008, (b) a discussion of the expandability of the FGT pipeline system into Florida, (c) information on the gas supply, (d) status information on the FGT Phase V expansion project, and (e) information on FGT system reliability.

FIRM GAS TRANSPORTATION CAPACITY FOR THE YEAR 2008

Florida Gas Transmission Company (FGT) is an open access interstate pipeline company that transports natural gas for third parties from Texas to Florida, with deliveries primarily to the State of Florida. FGT's pipeline system was originally placed in service in 1959. FGT has periodically expanded its system capacity to keep pace with the growth in demand for natural gas in Florida. In July 1987, FGT placed its Phase I Expansion in service, increasing its firm average delivery capacity from 725,000 MMBtu/day to 825,000 MMBtu/day. In December 1991, FGT placed its Phase II Expansion in service, increasing its firm average delivery capacity by 100,000 MMBtu/day to 925,000 MMBtu/day. In March 1995, FGT placed its Phase III Expansion in service, which increased its firm delivery capacity by approximately 530,000 MMBtu/day to a total of 1,455,000 MMBtu/day. On December 1, 1998 FGT filed an application with the Federal Energy Regulatory Commission (FERC) for the Phase IV Expansion which is planned to go in service May 1, 2001 and will increase average daily delivery capacity by 272,000 MMBtu/day to a total of about 1,727,000 MMBtu/day.

FGT's seasonal load profile is the opposite of most interstate pipelines in that its sustained system peak load is in the summer. This is because the electric generation customers in Florida account for approximately 80% of the throughput on FGT's system. They have a seasonal load pattern characterized by higher summer demands due to their airconditioning load requirements. FGT also transports gas for Florida local distribution companies that have a seasonal load pattern characterized by high demands during the winter due to heating requirements of their residential and small commercial customers. FGT also serves industrial customers in Florida that take gas at fairly constant rates during the year, as well as industrials that take gas on a seasonal basis.

There is approximately 16,800 MW of gas fired generating capacity in Florida of which only about 670 MW does not have dual fuel capability. FGT estimates that, of the 1,455,000 MMBtu/day total FGT firm transportation capacity into Florida, the electric customers have about 1,210,000 MMBtu/day in the summer season. The total daily gas capacity held by electric customers which have gas fired base load generation facilities with either no alternate fuel or only No. 2 fuel oil as the alternate fuel are approximately 890,000 MMBtu/day. The remaining capacity held by electric customers, 320,000 MMBtu/day, is used primarily for generating plants with No. 6 oil as the alternate fuel.

The 1999 Florida Reliability Coordinating Council (FRCC) Ten-Year Plan shows that approximately 5,400 MW of gas fired combined cycle units will be installed from 2000 through 2008. (Combined cycle units planned for 1999 will not require FGT system expansion.) Assuming a heat rate of 6,600 Btu/kWh, the firm gas transportation capacity needed for the new combined cycle units will be about 860,000 MMBtu/day. As the electric customers install new efficient gas fired combined cycle units, the older and less efficient gas and No. 6 oil dual fueled units will become intermediate loaded units. The firm gas transportation capacity, 320,000 MMBtu/day, currently used for the gas and No. 6 dual fueled units, will be used for the new base loaded combined cycle units. The net increase in firm gas transportation capacity required for power generation will be 540,000 MMBtu/day.

Based on historical demand data and Florida population projection by the University of Florida, Bureau of Economic and Business Research, FGT estimates that there will be an additional 45,000 MMBtu/day demand from the residential, commercial and industrial sectors by the year 2008. Including this estimate, the total expansion requirements for FGT by 2009 will be 585,000 MMBtu/day.

EXPANDABILITY OF FLORIDA GAS TRANSMISSION SYSTEM

At this point in time following the Phase III expansion, FGT has a pipeline system which is generally comprised of three parallel lines of 24-inch, 30-inch and 36-inch diameters respectively. The 36-inch pipeline, constructed in Phase III, is only partially compressed. The initial expansions can be accomplished by adding additional compression capacity to the existing pipeline.

When the existing pipeline system reaches a design capacity where the compression installed is balanced with the installed pipeline physical characteristics, our engineers will design for the next incremental capacity with both additional compression and pipeline looping. Pipeline looping is simply building another pipeline parallel to the existing pipelines for the distance necessary to efficiently increase the capacity to that quantity which fulfills the customers' incremental requirements. For an existing system, such as FGT's, it is necessary to build the pipeline loop only for the distance needed between each compressor station to attain the incremental capacity.

This ability of partially looping between compressor stations allows FGT the flexibility to design and build only the partial pipeline looping and compression to meet the market needs at a much lower capital requirement than would be possible if the current pipelines were not in place.

Expansion of FGT's system in Florida can be tailored to meet any size market by partial looping and adding compression. This is an advantage that the existing FGT system has over a new grassroots system. Obviously, some new lateral pipelines will be required to access market areas not now served by the FGT system, and loops or partial loops will be required to serve expanded loads at some existing locations.

As far as the timing for the construction of pipeline expansion facilities is concerned, depending on the scope and design of the expansion project, FGT would estimate twenty-four to thirty-six months to obtain all permits, environmental and regulatory approvals, and to complete construction of any pipeline and compression facilities required.

GAS SUPPLY

The future gas supply outlook is very positive. The estimates of the Gulf's resources range from 155 Tcf (Potential Gas Committee) to 162 Tcf (Minerals Management Service). The Department of Energy in its "Annual Energy Outlook 1999" forecasts that offshore production in the Gulf of Mexico will increase from the current production levels of about 5 Tcf per year to 6.5 Tcf in 2005. Gas industry sources are reporting up to 3 Bcf/day of new gas supply is expected to begin production in the next few years.

The FGT supply area extends from South Texas to Alabama and is strategically located to provide access to both offshore and onshore gas supplies. This vast supply area access to numerous offshore and onshore supply basins provides geographical diversity that helps better insulate FGT customers from unexpected shutdowns of gas supply and also allows customers to take advantage of the various supply options and competitive marketplace for the purchase of gas supply.

FGT provides access to onshore gas supply via the following:

- Direct connect plant and production points
- Over 40 interconnections with intrastate and interstate pipelines
- Access to Canadian gas supplies via the national pipeline grid

FGT also provides direct access to gas storage facilities in Texas, Louisiana, and Alabama and access to other storage via intrastate and interstate pipeline interconnections

In the overall supply area, FGT has total receipt point capacity in excess of 4.5 Bcf/day, approximately 3 times the mainline throughput capability.

PHASE V EXPANSION

FGT recently conducted an open season, which concluded April 30, 1999, to solicit requests for incremental firm transportation service beginning in 2002. FGT has obtained firm service commitments in excess of 230,000 MMBtu/day for participation in the Phase V expansion project. FGT has ongoing negotiations in progress with additional customers who desire to participate in the Phase V Expansion project. FGT plans to file the Phase V Expansion project application with the Federal Energy Regulatory Commission by the 4th quarter of 1999. The target in-service date for the Phase V Expansion is April 2002.

SYSTEM RELIABILTY

FGT has an excellent reliability record. Only two mainline outages have occurred in the last 30 years. In 1967 at a time when FGT had only one 24-inch mainline serving the state, FGT lost the mainline after it was damaged by a third party. The pipeline was repaired and back in full service after 16 hours. In 1998 a mainline outage occurred resulting from a lightning incident at Compressor Station 15 near Perry Florida. FGT was able to utilize strategically located line pack inventory in the Florida Market Area to meet high priority service needs during the outage. The pipeline was restored to 55% of capacity within 48 hours and 90% of capacity was back in service within 72 hours. Although the Compressor Station 15 incident was an unprecedented incident not only on FGT, but in the gas industry, FGT has taken steps to significantly enhance reliability through enhanced lightning protection and a lightning early warning system, relocating certain critical pipeline facilities, improving the emergency shut down facilities at compressor stations, and upgrading certain valve operators and procedures. As a result of these measures, it is physically impossible to have a failure of the system as we had at Station 15 and overall system reliability has been substantially improved.

FGT has several features which enhance operational reliability. FGT has multiple mainlines which run from the Supply Area in Louisiana, Mississippi, and Alabama to South Florida. Over 99% of the approximately 4,800 miles of pipeline on the FGT system is buried underground. At the compressor stations FGT has multiple compressor units, which allow FGT to take units in and out of service without affecting our ability to meet market service requirements. In addition, the design of the FGT system provides a market area grid which increases reliability by providing alternate routes in the event of an emergency. And finally, FGT's vast supply area access provides geographical diversity that helps insulate customers from catastrophes such as hurricanes and other unexpected shutdowns of gas supply.

CONCLUDING REMARKS

FGT is well positioned for cost effective pipeline expansions in the future. Given the infrastructure we have in place we are able to expand our system primarily through the addition of pipeline looping and the addition of compression at existing compressor station sites. This is a very economical way to bring incremental gas supplies to Florida, and minimizes the impact on land use and the environment.

FGT's expansion strategy is to construct smaller expansions, which closely match market demand, and to work closely with existing customers to facilitate capacity release transactions where market needs have decreased.

The location of FGT's pipeline system affords it an excellent opportunity to connect new reserves discovered anywhere in the onshore and offshore Gulf Coast areas to meet the future gas requirements of the State of Florida on a timely and competitive basis.

FGT's Phase IV expansion will increase average daily capacity 272,000 MMBtu/day. At this time FGT has obtained firm commitments for the Phase V Expansion in excess of 230,000 MMBtu/day and is in negotiations with several other customers. FGT's Phase IV and Phase V expansions will add annual average daily capacity in excess of 500,000 MMBtu/day by 2002 and will more than satisfy the projected baseload requirements for the State of Florida for the first several years of the next century.

Please call me at 713-853-3162 if you have any questions or desire additional information.

Sincerely,

R. E. Hayes

Robert E. Hayes, Jr.
Vice President Marketing

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