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TAMPA ELECTRIC COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 992014-EI

TESTIMONY
AND EXHIBIT OF

GREGORY J. RAMON

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

GREGORY J. RAMON

Q. Please state your name, address, occupation and employer.

A. My name is Gregory J. Ramon. My business address is 702 North Franklin Street, Tampa, Florida, 33602. I am General Manager, Energy Delivery System Planning & Services for Tampa Electric Company ("Tampa Electric" or "company").

Q. Please provide a brief outline of your educational background and business experience.

A. I entered the United States Air Force in 1965. After an honorable discharge, I graduated from the University of South Florida in 1974 with a Bachelor of Science in Electrical Engineering.

I joined Tampa Electric in the same year. In my 25 years with the company, I have held a number of Transmission and Distribution (T&D) engineering and planning positions. I became Manager, Transmission Planning in

1982 and in 1985 was given the additional responsibilities of distribution planning. In 1987, I became Assistant Director, System Engineering, with responsibilities for the functions of T&D planning, system protection, T&D system performance and T&D construction budgeting. In 1989, I became Assistant Director, System Engineering & Construction, with responsibilities for the functions of T&D and substation engineering as well as T&D standards. In 1992, I took my present position of General Manager, Energy Delivery System Planning & Services, with responsibilities for the functions of T&D planning, system protection, construction coordination and services, facilities information and technical support.

I have been a member of several Florida Electric Coordinating Group (FCG) committees and, in 1989 and 1990, I served as the Vice-Chairman and Chairman, respectively, of the FCG System Planning Committee.

I am also active in the IEEE Power Engineering Society, having served as Chairman of the Real Time Rating Task Force and as a member of the Long-Range System Planning Committee. I am presently a member of the Advisory Council for a new working group titled "Economic &

Technical Analysis for Transmission-Only Entities."

Additionally, I am very active in North American Electric Reliability Council (NERC) efforts, particularly Interconnected Operations (Ancillary) Services (IOS). In 1996-1997, I served as Chairman of the IOS Working Group and am currently serving on the IOS Implementation Task Force.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to demonstrate that the existing Gannon Station site is essential to Tampa Electric's and Florida's transmission system reliability. This demonstration contrasts the transmission impacts of the Gannon Repowering Project (GRP) with the transmission impacts of replacing Gannon Station capacity with capacity purchased from third parties that are remote from Tampa Electric's service area.

My testimony will show that replacing Gannon Station capacity with capacity purchased from third parties that are remote from Tampa Electric's service area would cause extraordinary overloads and voltage stability problems on the Tampa Electric and the state grid. Additionally, system losses would increase significantly on the Tampa Electric and the state grid, resulting in the need for additional generating capacity and increased operation and maintenance (O&M) expense. Also, the purchase of remote capacity will require procurement of transmission service at additional costs for wheeling of the purchased energy to Tampa Electric.

Finally, my testimony will demonstrate that the process to enter into a capacity purchase from third parties for the replacement of Gannon Station capacity would be complex and time consuming. This process, especially the determination of transmission requirements, construction agreements and cost allocation, would be overly burdensome and present a high risk of causing delay in the availability of any such purchased capacity alternative.

In all cases analyzed, the transmission costs of purchasing capacity from sources that are remote from the Tampa Electric service area would be significantly more than the costs of the GRP. Transmission cost estimates for the purchased capacity alternative are estimated to be approximately $400-500 million on a cumulative present worth (CPW) basis. These transmission costs are incremental to the generation costs of the purchased power alternative.

My testimony will demonstrate these impacts by providing:

1) A description of the Gannon Station and its relationship to the Tampa Electric transmission system and load centers;
2) A transmission analysis of the purchased capacity case, identifying reliability problems and cost estimates of construction requirements, system losses and transmission service requirements; and
3) An explanation of the complexity of reaching third party and utility agreements that would likely delay the dates that purchased capacity could be available without causing reliability problems on the Tampa Electric and the state grid.

Q. Have you prepared an exhibit supporting your testimony?

A. Yes. My Exhibit No. ___ (GJR-1), consisting of five documents was prepared under my direction and supervision.

Q. Please describe the relationship between Tampa Electric's existing generation at Gannon Station, Tampa Electric's transmission system and Tampa Electric's load center.

A. Gannon Station is located in Port Sutton on Tampa Bay. It is connected into Tampa Electric's bulk transmission grid via five 230 kilovolt (kV) transmission lines, one 230/138 kV transformer and three 138 kV transmission lines. Gannon Station has an aggregate summer capability of 1,117 Megawatts (MW) of real power and 702 Megavars (MVAR) of reactive power, which represents 32 percent of Tampa Electric's real power output capability and 30 percent of the synchronous reactive power output capability connected to Tampa Electric's bulk transmission grid.

By virtue of its extensive bulk transmission interconnects, its centralized location relative to Tampa Electric's system load and its real and reactive power output, Gannon Station is a cornerstone of the Tampa Electric bulk power system. Documents 1, 2 and 3 of my Exhibit illustrate Gannon Station's centralized location. The Tampa Electric transmission system has been purposely planned around this bulk power source for over 30 years. Were it not for this source of real and reactive power near Tampa Electric's load center, extensive additional transmission plant would be required to maintain reliability and provide cost effective electric service to Tampa Electric's customers.

Q. How did Tampa Electric analyze the potential impacts on the transmission system of the GRP and its alternatives?

A. Tampa Electric utilized several traditional methodologies in evaluating the transmission impacts of the GRP and its alternatives. All of these studies utilized the Florida Reliability Coordinating Council's (FRCC) loadflow databank cases. The FRCC loadflow databank is a repository of transmission simulation models constructed by a team of engineers from the transmission-owning companies in peninsular Florida. The FRCC loadflow cases model the topology of the Florida and Southeastern United States transmission system as it exists today and as it is planned over a ten-year horizon. In addition to simulating the configuration of the electrical components of the transmission system, the FRCC loadflow databank captures peak load conditions by season, generation additions as dictated in the FRCC Ten-Year Site Plans, economic generator dispatch and inter-utility power interchange according to firm power contracts. Power Technologies Inc.'s (PTI) Power System Simulation-

Engineering (PSSE) load flow software was used to analyze the potential impacts of the GRP and its alternatives.

In analyzing the impacts of the GRP and its alternatives, I employed scenario modeling and contingency analysis. The FRCC loadflow databank cases served as a starting point with change cases created from these models as necessary to simulate the alternatives considered. Tampa Electric and FRCC transmission contingency lists were employed to screen for system problems. From these cases and contingency analysis results, incremental impacts were determined and alleviating projects and costs were established.

Q. What alternatives were considered given Tampa Electric's environmental compliance requirements?

A. As described in the direct testimony of Tampa Electric witness Mark Ward, numerous alternatives were considered and four alternatives were ultimately evaluated. The first alternative called for the installation of environmental equipment at Gannon and Big Bend Stations to permit their continued operations as coal-fired stations. The second alternative was the GRP. The third alternative called for the replacement of the existing

Gannon Station generators with combined cycle units at the existing Gannon Station site. The final alternative called for the purchase of the equivalent of the entire GRP generating capacity from third-party resources.

Q. Please summarize the transmission system impacts of each alternative.

A. The first three alternatives did not involve significant changes to the generating output of Gannon Station and, therefore, presented minimal adverse impacts to Tampa Electric's transmission system. However, the purchased capacity alternative significantly impacted the reliability of the Tampa Electric and the state grid. Voltage collapse and thermal overloads on the Tampa Electric and the state grid would be a direct consequence of purchasing replacement capacity for Gannon Station from remote sources. Other impacts with cost consequences include increased system losses and the cost of transmission service for wheeling the capacity purchases.

The cost impacts of the purchased capacity case are estimated to be between $400 and $500 million on a CPW basis consisting of:

1) $70-$120 million for construction of lines and equipment;

2) $52 million for special construction of Flexible AC Transmission Systems (FACTS) devices to resolve reactive power supply problems;

3) $56 million for increased system losses on Tampa Electric's system;

4) $86 million for additional system losses on the state transmission grid; and

5) $147 million for transmission services.

Q. Please describe further the impacts discussed above.

A. The purchase of replacement capacity for Gannon Station from remote sources would impact transmission system reliability and result in significant economic impacts. System reliability would be impacted in three ways. First, a Gannon Station shutdown would result in voltage instability and collapse on Tampa Electric's transmission system. Second, purchasing replacement capacity from remote sources would have significant system thermal loading impacts. Finally, purchasing replacement capacity would result in significant statewide transmission system impacts.

Tampa Electric's most significant transmission system performance concern would be the resultant voltage instability of the Tampa Electric (and possibly the State of Florida) power system. A system voltage collapse on at least the Tampa Electric system would be brought about by a serious deficiency in reactive power supply. The laws of physics make serving local reactive power from a distant source inherently unstable.

Even if this voltage instability could be addressed, the resultant thermal overloads would necessitate extensive additions to the bulk and sub-transmission system. This transmission construction would be required to alleviate system overloads to transport purchased capacity to Tampa Electric's load center.

There would also be impacts on Florida's overall transmission system, particularly on Florida Power Corporation's (FPC) Brookridge Corridor, where overloads could occur. Depending on the location of the purchased capacity sources, there could be a need for siting and construction of major bulk transmission facilities. Moreover, some of the additional transmission facilities would likely have to be sited and constructed by other utilities, thus adding controversy to a process that is already time-consuming and costly.

The required Tampa Electric and state projects could include construction of inter- and intra-utility transmission lines with voltages ranging from 230 kV to 500 kV. This construction would likely fall under the Power Plant Siting Act ("PPSA") or the Transmission Line Siting Act ("TLSA") requirements. There are no requirements under the PPSA or TLSA for the GRP.

In addition to compromising system reliability, the purchased capacity alternative would substantially increase the Tampa Electric and statewide transmission system losses, an impact that is directly attributable to the supply of replacement power from a greater distance. This increase in system losses would necessitate the acquisition of additional capacity resources and would increase generation O&M expenses.

Finally, the purchase of remote capacity would also require the procurement of transmission services for importation to the Tampa Electric system. To serve its load with imported capacity purchased from third parties, Tampa Electric would need to reserve long-term, firm transmission services from the appropriate transmission provider(s).

Q. Why are the impacts of the alternatives so much greater than the impacts of the GRP?

A. In simple terms, the transmission capacity is basically in place today to adequately transmit energy and capacity from the Gannon Station site. The extraordinary impacts of the alternatives can be understood further by recognizing that Gannon Station is physically located near the load center of Tampa Electric's service territory and provides approximately 30% of the total Tampa Electric energy and demand requirements. For over 30 years, the Tampa Electric grid and the state grid have been planned and built with the Gannon Station resource located near the Tampa Electric load center. Replacing that capacity with purchased capacity from remote sources would result in a severe impact to both the Tampa Electric grid and the state grid requiring an extensive redesign at extraordinary costs.

Q. Does this mean that remote, non-utility generation is always impractical, costly and inefficient with regard to transmission costs?

A. No, but this case is not typical. The remote purchased power alternatives are <u>replacing</u> power generated from an existing large plant near the load center of Tampa Electric. The transmission infrastructure required for generation located at or near the ultimate load is minimal compared to the required infrastructure to replace it with remote generation possibly hundreds of miles away.

In this case, from a transmission perspective, the use of remote generation is not practical or efficient. Replacing the GRP capacity with remote purchased capacity would have dual repercussions in that it would be necessary, first, to upgrade the grid to interconnect new generation sources, and second to redesign the Tampa Electric grid <u>and</u> the state grid capacity to replace estimated to be between $400 and $500 million on a CPW basis consisting of:

Q. Are there other factors to consider with respect to local and remote generation from a transmission perspective?

A. Yes. It is impractical, inefficient and possibly infeasible to serve a major load center wholly with remote generation resources. While the power industry has developed large amounts of generation that are remote from major load centers, a significant amount of generation remains in or very near large load centers because of reliability concerns, the high cost of transmission and the multifaceted problems of transmission siting.

Q. Please describe the scenarios that you used to simulate replacing Gannon Stations capacity through purchased capacity from remote sources.

A. In assessing the purchased capacity option, Tampa Electric investigated a scenario with purchases originating in varying locations to observe the resultant transmission system impacts. The scenario considered to be most reasonable was a situation in which purchased power was received from multiple and viable sources throughout the State. The sources for the replacement capacity were assumed to be Panda's Leesburg Project, Duke's New Smyrna Beach Project, Reliant's Central Florida Project, Constellation's Oleander Project, and Panda's Ft. Pierce Project. Documents 3 and 4 of my exhibit illustrate the location of these sites relative to the state transmission grid and Tampa Electric. The amount of capacity taken from each source was based on the proportion each source represented of the total generation in the five sources. In studying this scenario, Gannon Station was completely shut down in the loadflow model with interchange modeled between each source plant and Tampa Electric.

Q. Why did you select five sources?

A. For several reasons. First, the purchase option is significantly larger than any one generator's announced capacity at one location. Second, for both economic and reliability reasons, a minimum of three locations or three generators may be required. Third, from a transmission standpoint, allocating the purchase over several locations mitigates transmission impacts because the five locations are geographically diverse. From a transmission impact perspective, this allocation method can be considered an average or median case because it attempts to mitigate the impacts which would arise from a purchase of all of the required capacity from a single location and thus does not bias the results towards a certain transmission path, provider or constraint.

Q. Why did you select these five particular units?

A. At the time of the analysis, these were the largest non-committed incremental generating units proposed for peninsular Florida within the time frame in question. These five units had been announced in the press for some time prior to the date of the analysis. Since that time, other energy companies have announced generation projects in the State of Florida. Other combinations of locations can produce impacts different from the allocated case chosen. As the testimony will demonstrate, other combinations of locations remote from Tampa Electric would still result in significantly higher costs than the GRP.

Q. Based upon this analysis, what were deemed to be the technical consequences of the reliability problems described previously?

A. First and foremost, removal of the reactive power source provided by the synchronous generators at Gannon Station would result in voltage collapse on the Tampa Electric system. While the costs to resolve this problem are significant, the most important factor to consider in deciding its resolution is the potential consequences of voltage collapse. Failure to adequately address this problem could result in a partial or complete blackout of

Tampa Electric's system.

Q. Please describe in basic terms how voltage collapse is directly related to elimination of capacity supply at Gannon Station.

A. The voltage collapse phenomenon can be observed with any FRCC loadflow databank case: simply disconnect the Gannon Station generators, model replacement of the Gannon Station generators at other locations in the state, and attempt a solution of the resultant loadflow model. The loadflow case will not reach mathematical convergence because of the enormous mismatch between reactive load and supply at the Tampa Electric load center.

To prove that this problem is related to Gannon Station, take the same loadflow model and simulate the construction of a zero length (zero impedance) 230 kV transmission line between the Gannon Station 230 kV bus and any other large 230 kV generating station. This loadflow case will solve because real and reactive power is supplied directly to the Tampa Electric load center via the new "zero impedance" line. Next, slowly increase the impedance of this new transmission line; this in effect simulates the actual distance between Gannon

Station and other generating stations. Very quickly a point is reached at which the case will no longer converge. This loadflow simulation demonstrates the problems associated with attempts to supply reactive power from remote locations. The simulation also demonstrates that the remote power system will absorb most of the remote reactive supply while leaving Tampa Electric deficient in reactive supply. Long lines and high power transfers prevent the transmission of reactive power over long distances.

To further reinforce this point, start with a fresh FRCC loadflow databank. Leave the Gannon Station generators in the loadflow case but reduce their real power output to zero. This simulates operation of Gannon Station as what is known as a synchronous condenser where the units exist solely to generate reactive power. This case will reach a stable solution, further proving the need for a strong reactive power source at the Tampa Electric load center.

Q. Is this the extent of the transmission system impacts caused by the replacing Gannon Station capacity with capacity from off-system?

A. No. In addition to the system voltage problems, replacement of Gannon Station generation with purchase capacity causes a substantial increase in bulk system power flow to Tampa Electric from generation sources modeled throughout the state. This results in several transmission system overloads, which would require extensive 230 kV transmission construction through Polk and Hillsborough Counties. Because required transmission solutions would require cross-county construction, Tampa Electric would be required to commence the TLSA requirements and procedures which would likely be controversial, time consuming and expensive.

In addition to playing an integral role in the reliability of Tampa Electric's bulk transmission system, Gannon Station is also one of the few power sources for the Tampa Electric 138 kV transmission sub-system. Removal of this power source results in thermal overloads and low voltage throughout the 138 kV and underlying 69 kV sub-transmission system. Because most of Tampa Electric's 138 kV transmission sub-system is located on the Interbay peninsula, Tampa Electric has very few sourcing options for this system other than Gannon Station.

On a statewide basis, replacement of the Gannon Station generation source with off-system purchases is likely to force violations on the Brookridge Corridor under peak load conditions. Every year the FRCC calculates the distribution factor on each constrained interface for shifting of generation between major power stations. The weighted-average FRCC distribution factor on the Brookridge Corridor for shifting generation between Gannon Station and generation stations across the state is approximately 30 percent. In other words, for every 100 MW removed from Gannon Station and replaced with off-system purchases, it is estimated that loading on the Brookridge Corridor will increase by 30 MW. Since the planned GRP has a peak summer output of 1,409 MW of generation, the Brookridge Corridor loading would increase by approximately 423 MW. Because the Brookridge Corridor is currently already loaded at or, at times, above its capacity, this would be an unacceptable consequence.

Q. Please describe in detail the transmission projects that would be required, and the resultant costs, if the Gannon Station were shut down.

A. An extensive amount of transmission expansion would be required to accommodate the replacement of generating capacity at Gannon Station with capacity purchases. The following list briefly describes the major projects that would likely be required to alleviate the problems I have identified:

- To prevent voltage collapse, a reactive power source must be maintained near the Tampa Electric load center. The viable options that would be considered would be the conversion of Gannon Station to synchronous condensers or the installation of FACTS devices. A stability study would be required to determine the preferred option and the amount of reactive power supply required. A discussion paper on this subject, prepared for Tampa Electric by PTI, indicates that FACTS devices would likely be the option selected. The PTI paper is attached as Document 5 of my Exhibit. The costs of the FACTS devices could reach $52 million on a CPW basis.

- Because of the very large amount of power flow into the Tampa Electric load center from the state grid, the Tampa Electric system would require considerable expansion because of thermal overloads and steady state voltage problems. As previously mentioned, the existing

Tampa Electric grid capacity and topology is designed for local generation. Removal of that generation and replacing it with remote generation would result in a very different, large and excessive power flow on the Tampa Electric grid and the State grid. Many projects would be required including several 230 kV transmission projects involving transformers, new lines, switching stations, and the reconstruction of existing lines.

- Regarding the state system, the removal of the generation source at the Tampa Electric load center would unacceptably load the Brookridge Corridor, as previously discussed. One measure which could mitigate this problem could be the installation of three phase-shifting transformers at the northwestern edge of Tampa Electric's 230 kV system to back down the flow of power from FPC's system into the Sheldon Road substation. While these phase-shifting transformers would reduce the problem, they might not totally alleviate Brookridge Corridor loading impacts which could require other 230 kV or 500 kV solutions to be built by other utilities in the state.

- The incremental cost of the above expansion for overloads and steady state voltage problems will be approximately $70 million on a CPW basis.

Q. What does Tampa Electric's study reveal about transmission losses if Gannon Station capacity were to be replaced from remote sources?

A. In addition to the above-stated transmission system inadequacies, transmission system losses would increase by approximately 53 MW on the Tampa Electric system, while losses across the peninsular Florida transmission system would increase by approximately 82 MW (peak load, summer 2005), exclusive of the Tampa Electric system loss increase. This increase in losses would require the addition of at least an additional 135 MW of generation capacity across the state to maintain the same level of net state generation capacity. The increase in Tampa Electric system losses would result in an increase in Tampa Electric's operating costs of approximately $56 million on a CPW basis, and an increase in operating costs to other utilities in the state of approximately $86 million on a CPW basis.

Q. For the purchased power scenario that you studied, which transmission providers were relied upon to provide transmission services?

A. It was assumed that FPC would wheel two of the sources of purchased power, Orlando Utilities Commission (OUC) would wheel one and Florida Power & Light (FPL) would wheel two.

Q. For the purchased power alternative that you studied, what would be the wheeling costs for importing the power?

A. There would be charges for transmission and ancillary services. The total costs of transmission services would be approximately $147 million on a CPW basis.

Q. You have described your base case as a median or average case in respect to transmission impacts. Please explain.

A. There are other locations within peninsular Florida, or different allocations of purchases, that Tampa Electric could have assumed which would have even greater adverse impacts on Florida's bulk transmission constraints and the transmission systems of Tampa Electric and others than the combination of sources chosen for the analysis. Remote generation directly to the north and east of Tampa Electric's service territory, for example, would result in considerably more costs than the diverse generation case presented as the base case.

A screening analysis of siting the replacement capacity to the north and east of Tampa Electric indicated that the economic cost of these scenarios would be significantly more than the modeled scenario by many millions of dollars. For example, assuming the placement of all of the Gannon Station replacement capacity to the north of the Brookridge Corridor would result in greatly elevated flow on the already-congested Brookridge Corridor. The consequences could be as severe as a need for construction of 500 kV transmission facilities with costs running into the hundreds of millions of dollars. Likewise, addition of the generation to the east of the Tampa Electric load center would exacerbate transmission loading throughout Tampa Electric's and central Florida's transmission systems. The resultant need for construction of 230 kV transmission facilities, while not as costly as the aforementioned 500 kV contingency, would be extremely expensive and difficult to accomplish.

Q. Are there locations in the state that would result in less costly impacts than the base case that you described previously?

A. Yes, but significant impacts would remain, particularly on the Tampa Electric system. Generally speaking, the closer generation is added to Gannon Station and the Tampa Electric load center, the lesser the physical and economic impacts. Addition of generation in Southwest Florida (Manatee, Sarasota, Charlotte, Lee Counties, etc.) could have a lesser impact to the state's transmission system than any of the scenarios already mentioned in this testimony. However, the addition of such generation could cause significant local impacts to the FPL transmission system. In any case, significant problems would remain on the Tampa Electric system due to the import of replacement capacity and the costs of transmission services from FPL. These factors combine to make the "south case" more costly than the GRP.

Q. Are there other considerations that must be taken into account in considering any purchased power alternative?

A. Yes. To reach a final agreement with third party suppliers involving interconnection and transmission services, a special, joint statewide study of transmission impacts must be made. Such a study would be necessary in this case because it is the only practical means to determine the transmission requirements for such a major shift in resources on the systems of individual providers without a statewide study. This joint study would require cooperation of all affected transmission providers and third parties to determine and reach a consensus on requirements and cost. Tampa Electric cannot control this process alone and could not guarantee a timely result. In fact, this process would very likely be controversial. It would not be an easy task to determine what should be built, who should build it and who should pay for it.

Once the optimum generation resources are identified, there are likely to be further delays associated with the necessary interconnection agreements between the generators and their local transmission providers, and the necessary transmission arrangements for delivery of the power. With reference to the latter arrangements, it is noteworthy that the Federal Energy Regulatory Commission's open access process includes a specific queuing procedure that requires pending requests for transmission services to be studied first. All of this can lead to delays and the proposals to serve the purchased capacity alternative could have to stand in line.

If the studies indicate multiple system impacts, additional problems could arise if one or more of the affected systems has no applicable open access tariff under which arrangements can be made, and thus is under no obligation to cooperate. Transmission providers that do have open access tariffs must follow a potentially lengthy process for making arrangements to provide transmission services.

These planning challenges are not unique to the matter at issue here but are an integral part of the planning and expansion issues that have been under consideration by this Commission for some time.

Transmission siting controversy is also an important factor to consider and could very well result in delay or abandonment of a transmission line proposed for construction. For example, the Lake Tarpon-Kathleen transmission line, which was first proposed in 1984, remained in a proposed status for over eleven years, tripled in estimated costs and was ultimately abandoned after this Commission entered its Order No. 95-1533-FOF-EI on December 12, 1995, declining to initiate a proceeding to determine the need for the line.

The costs and risks of transmission line construction are significant and indeed are entirely preemptive in this instance. This situation is further exacerbated by the fact that time is of the essence here. Tampa Electric is under a strict requirement to provide environmental emission reductions by dates certain. It would be reckless to select an alternative that imposes the transmission impacts and associated risks that the replacement of Gannon Station's capacity would produce.

Q. Please describe the technical impacts of pursuing a course of action that involves a repowering, replacement or environmental option at the Gannon Station site.

A. The GRP results in an increase in site capacity of only about 300 MW. The required transmission expansion is therefore minimal, because the transmission capability is basically in place. The transmission expansion cost of the GRP is approximately $13.5 million on a CPW basis, most of which is made up of costs associated with interconnection to the existing 230 kV. The need for significant transmission construction on the scale of the remote power purchases is avoided in this case.

Q. Would you please summarize your testimony.

A. Gannon Station is an integral and essential component of Tampa Electric's transmission system and is key to the performance of the Tampa Electric grid and the State grid. Selection of a generation expansion alternative other than replacing the Gannon Station capacity at the existing Gannon site would result in significant impacts on the Tampa Electric grid and the State grid. These impacts would lead to considerable and unnecessary investment in transmission and would result in impacts to third parties and other utilities requiring new state studies, interconnections, and an extensive TLSA process.

From a transmission planning perspective, the optimum solution for replacing the capacity from Gannon Station's coal-fired generating units is to replace the capacity at the Gannon Station site. This solution not only maintains the reliability of the transmission system, but it does so at the least cost.

Q. Does this conclude your testimony?

A. Yes it does.

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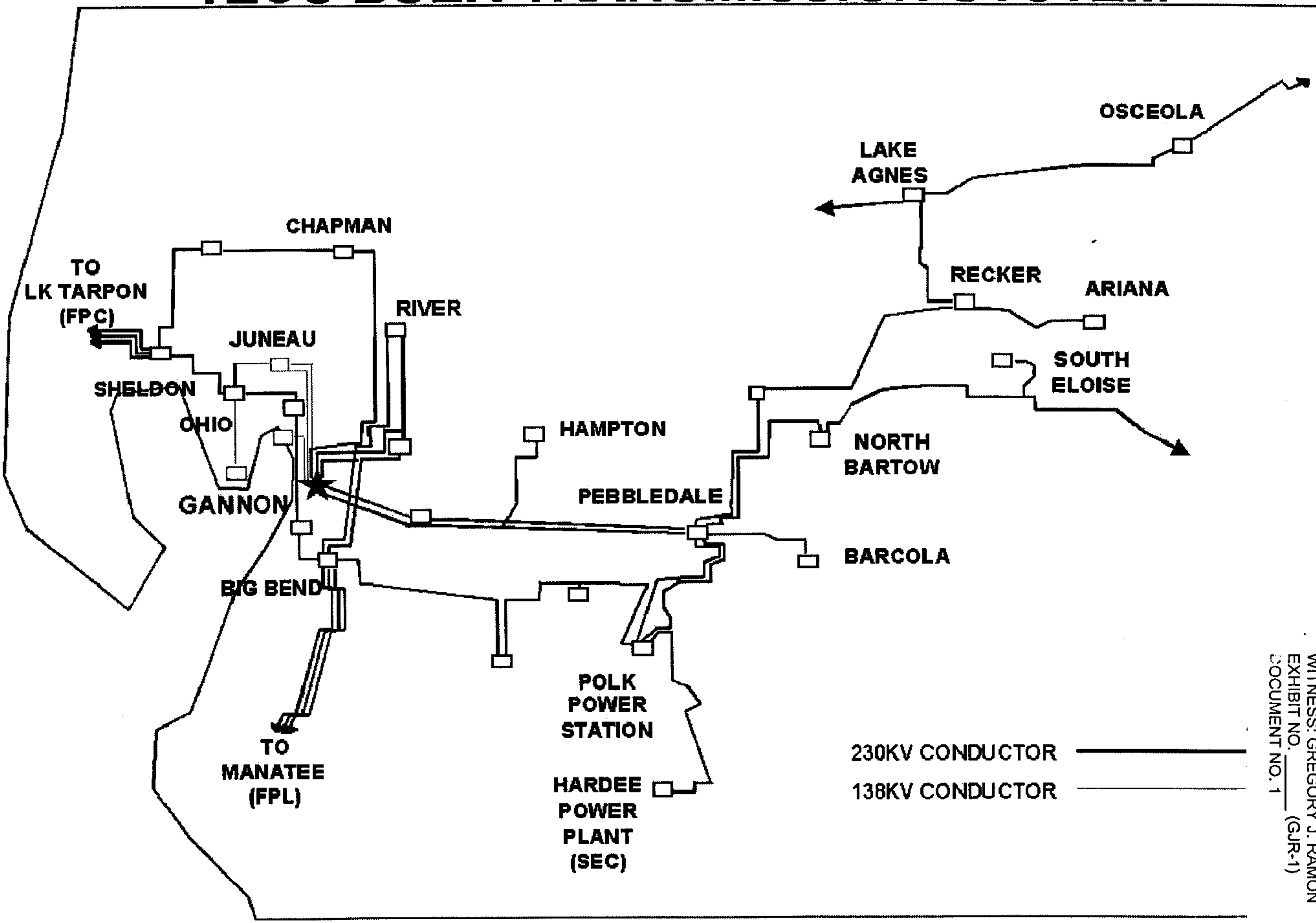

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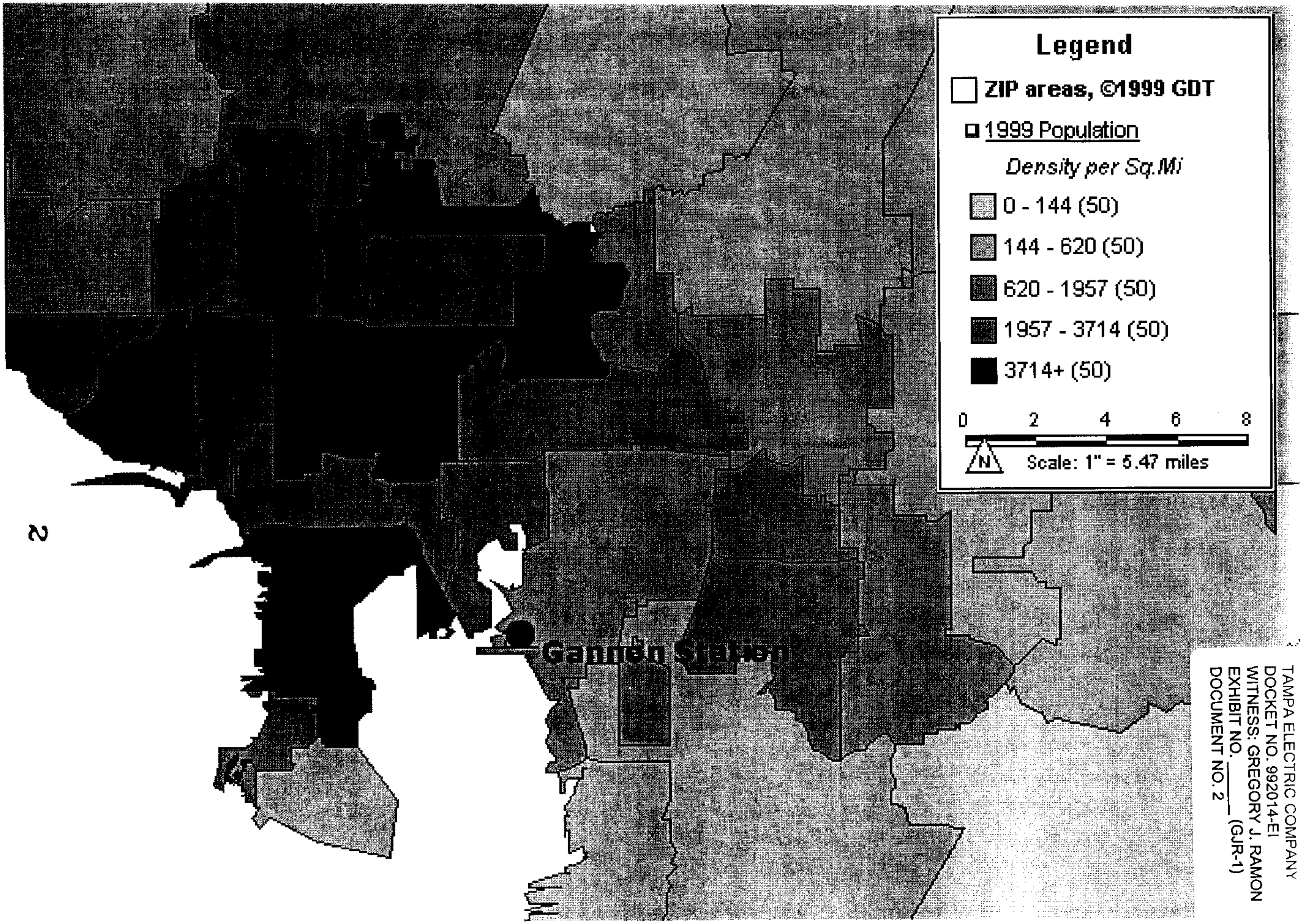

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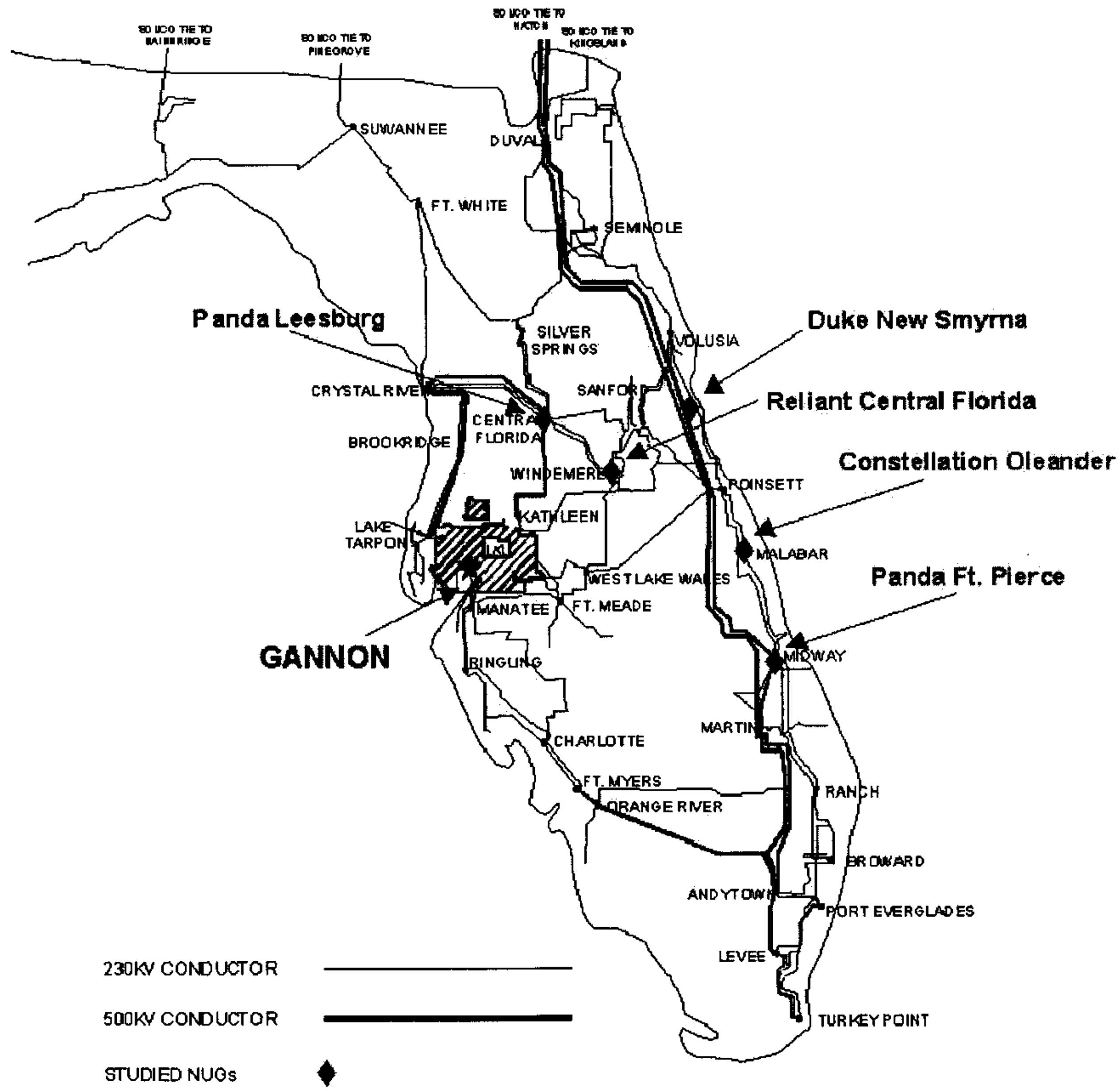
MAP OF PENINSULAR FLORIDA
MAJOR TRANSMISSION LINES & STUDIED NUGs



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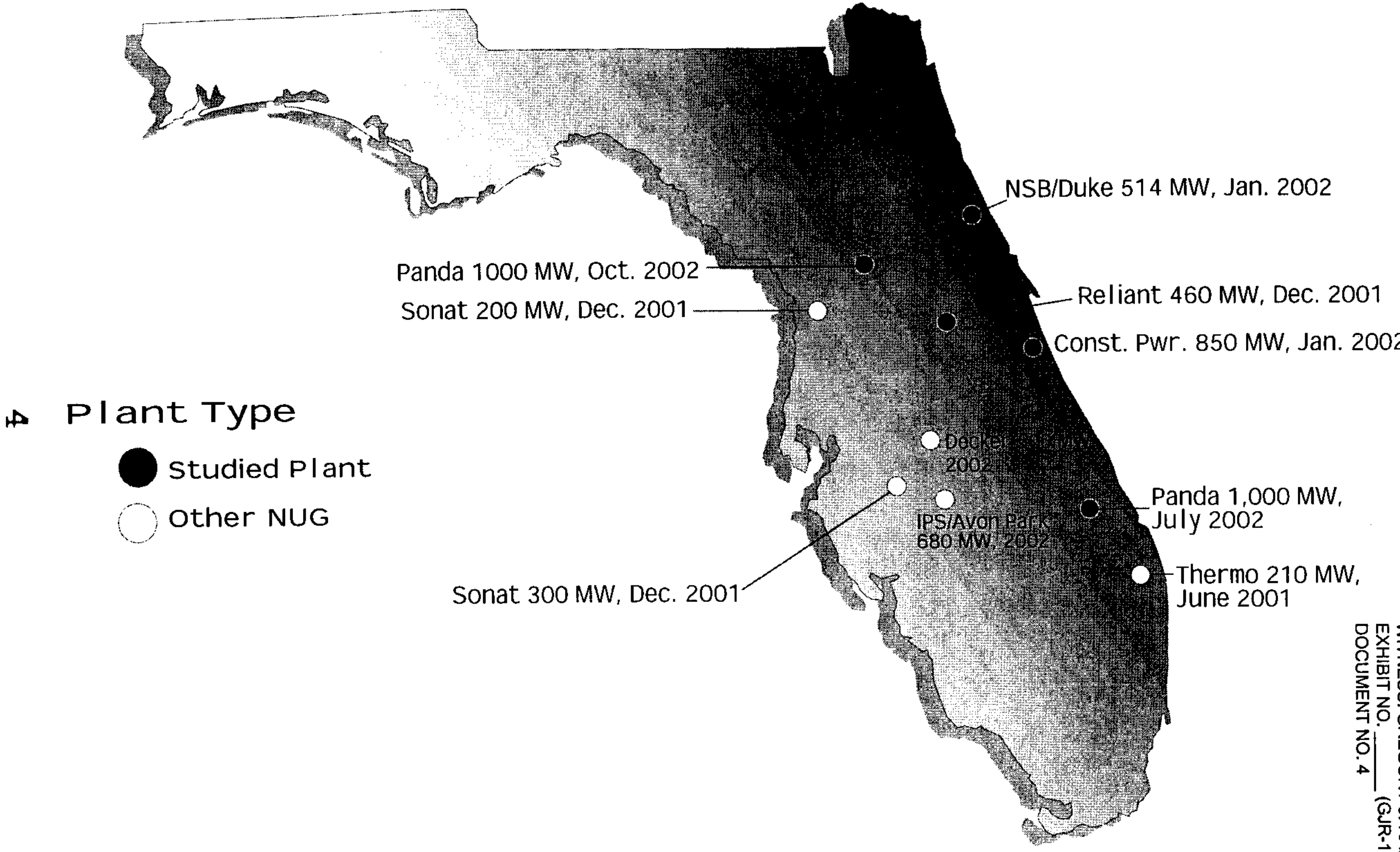
Announced Non-Utility Plant Additions As of November 1999



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DOCUMENT NO. 4

Discussion on the Options for Conversion of the Gannon Generators to Synchronous Condenser Operation or Addition of Controlled Static Reactive Compensation

1.0 Introduction

TECO Energy is presently considering the repowering of the Gannon plant. One option that has been suggested is that the energy that the plant supplies be instead purchased from the market, that is, the plant be shut down. TECO's studies have shown that the removal of the Gannon plant would create severe voltage problems in that area, due to the loss of the reactive supply of the plant (in addition to the need to import the power with the potential for increased transmission system reactive losses due to higher transfers). One potential remedy to the voltage problems seen in these preliminary studies is to add reactive supply at the Gannon plant site. Two alternatives would be conversion of the Gannon plant to synchronous condenser operation or addition of controlled static reactive compensation. PTI was asked to compile some background information regarding the potential for these two alternatives including feasibly and costs. Due to the short time available, the information gathered is not complete but hopefully will assist TECO in understanding the possibilities and discussing them with others. PTI has compiled whatever information was available in its internal files and has contacted external experts that were readily available.

2.0 Conversion of the Gannon Units to Synchronous Condensers

The Gannon power station consists of six steam units, ranging in size from 147 MVA to 495 MVA. The units are installed in a common building. One of the alternatives proposed is to convert some or all of the units from steam-turbine generators to synchronous condensers. A steam turbine power plant consists of four major components: the furnace, the boiler and steam supply system, the steam turbine, and the generator. Each component, in turn has many associated components, controls, and auxiliary equipment. The furnace combusts the fuel (coal, in the case of Gannon) and produces heat. The heat is transferred to the boiler, which produces steam and supplies that steam to the steam turbine. The steam passing through the steam turbine supplies mechanical energy to the turbine/generator shaft causing it to rotate, and thus thermal energy is converted into mechanical energy. The generator is on the same shaft as the turbine. The mechanical energy is converted to electrical energy by the generator. A dc voltage is applied to the generator rotor (the part of the generator on the shaft) through the generator's excitation system. This dc voltage causes a dc current to flow which, in turn, causes a magnetic flux to develop. When, due to the rotation, the magnetic field of the rotor passes over the coils of the wire that form the stator (the stationary part of the generator), an ac voltage is induced in the stator and electric power can be delivered to the system.

The conversion of the units to synchronous condenser operation would remove the need for the furnace, boiler, and turbine components. There would be no direct combustion of fuel. The energy required to turn the generators (condensers) would be supplied from the power system. This is the exact opposite of the present condition where the generators supply a large amount of power to the system; in this mode they would not supply power, but would become a user of power.

However, the situation is quite different for the reactive power. While the generator cannot supply real power (MW) in synchronous condenser mode, it can supply or absorb reactive power (MVAR). Reactive power is the component of power that cannot be used to perform actual work, but is necessary to "excite" magnetic fields. Reactive power is "consumed" in the magnetic fields that form around conductors or in the coils of ac motors or other load devices.

The amount of reactive power that is delivered to the system from the condenser is controlled by changing the "flux" level on the generator's rotor. This flux level is changed by raising or lowering the dc voltage applied to the field winding on the rotor. An increase in flux results in supply of more reactive power to the system, and a decrease in flux results in supply of less, or absorption of more, reactive power. Note that changes in flux cannot be used to get the synchronous condenser to supply power – there is no longer a source of mechanical power.

As noted above, power is required from the system for the synchronous condenser to operate. This power would be required to supply the excitation current to the rotor and rotor losses, the losses in the stator due to stator current, the rotational friction and windage losses in the generator, and other load and no-load losses. Rotational and windage losses would be essentially the same in synchronous condenser operation as in generator operation. Rotor and stator losses would change significantly, depending on the reactive output demanded by the system, but would not exceed those that occur under generator operation.

2.1 Conversion Process

The conversion of a generator to a synchronous condenser is a feasible, but involved, engineering project. It requires an analysis of the mechanical design of the generator/turbine shaft. The shaft is very heavy and is supported by bearings both at the ends and along the shaft. To reduce shaft weight and windage losses, the turbine would be removed. This removal of more than half of the shaft train necessitates the redesign of the bearings and supports, ensuring adequate distribution of weight and allowing for the axial movement of the shaft. Determining the costs involved would require knowledgeable engineers to visit the site and examine the equipment. The furnace and boiler systems would not be needed and could be decommissioned. The existing step-up transformers and substation switchgear may be used with little or no modification.

2.2 Starting of the Synchronous Condenser

A generator is started by the admission of steam into the turbine, which slowly begins to spin and, through control of the steam flow, is slowly raised up to synchronous speed. For all six steam units at Gannon, the synchronous speed (when the voltage waveform created by the generator has the same frequency as the power system) is 3600 rpm. When the generator speed is matched to the system frequency, the generator is synchronized to the system by the closing of a circuit breaker and can then begin to deliver power. As there is no turbine or steam supply in synchronous condenser mode, another means must be employed to bring the machine up to speed. Direct starting of the synchronous condenser (just switching it in like one would start a smaller motor) could not be done, since the starting currents of thousands of Amps would cause severe system problems. In addition, the machine is not designed for the continuous application of the forces or heating that would result from these high starting currents). There are two primary methods of starting a synchronous condenser: use of a motor or use of a static starter.

A motor can be used to start the synchronous condenser. Such a motor is often called a "pony" motor. It would most likely be an induction motor of the wound rotor type, where speed could be controlled by changing of the rotor resistance. The motor would be connected to the generator shaft. Direct connection would be simpler, but connection through a clutch arrangement would allow the motor to be disconnected after the unit was brought up to speed for synchronization to the system, reducing windage losses when operating. This would be a specially designed motor, sized for the mechanical load required to bring the generator up to speed and having the capacity to handle the starting currents required for the long starting period (probably several minutes). One motor would be required for each generator. Each of these motors would be designed to match the generator it would be connected to. The motor must be sized to overcome bearing and windage losses, not the full operating loss – that is, not the stator and rotor losses. It would thus be much smaller in size than the generator, probably on the order of one to two percent of the generator rating.

The static starter would be a variable frequency converter. It would convert the 60 Hz system supply to a variable frequency/variable voltage-magnitude ac supply. There are several technologies for this conversion process, employing different types of power electronics and control strategies. In essence, they all do the same thing – by controlling the voltage and frequency of the supply to the synchronous condenser, they can control the power and current supplied, thereby starting the condenser and bringing it up to speed at a desired rate without excessive demands on the system or the machine.
Probably only one static starter would be required. It would, however, need to be designed to handle the largest unit, both in terms of power requirements and voltage level. The six units have different rated voltages and power demands due to their different sizes and ages. This could be handled by the controls of the static starter, but would need to be designed as part of the conversion process. The generator hall would require extensive electrical work to supply the starter voltage and current to all of the six units and to allow throwover to the utility system when conditions are reached for synchronization. Of course, only one unit could be started at a time. The static starter would not run continuously, only during the relatively short starting process (once again, several minutes). Thus, its energy costs would not be very significant in the total cost calculation.

2.3 Reactive Capabilities of the Synchronous Condenser

The reactive power that can be produced by the synchronous condensers would be determined by the capability curves of the units. An estimate would be that the units could produce reactive power output (MVAR) of about 60% of the generator MVA rating. Reactive power absorption would be much more limited, probably on the order of 20% to 40% of rated. Thus, the six synchronous condensers at Gannon might be capable of producing as much as 900 MVAR and absorbing around 450 MVAR. The stator current would not be the limiting element; rather the limit would probably be due to field heating during reactive power output and end turn heating during reactive power absorption.

The amount of reactive power supplied by the synchronous condenser is controlled by adjusting the field voltage and current. This adjustment would be performed by the voltage regulator of the machine as presently occurs, to control voltage to a desired value.

3.0 Controlled Static Reactive Compensation

An alternative to a synchronous condenser is static reactive compensation. There are different implementations of such devices. All perform the basic function of supplying reactive power to the system (or absorbing it from the system) by means of power electronics, often coupled with capacitors or reactors. The two major types are the static var compensator (SVC) or the static condenser (STATCOM). The SVC uses thyristors, whereas the STATCOM uses gate-turn-off (GTO) devices. There are different variations of SVC, for example, the thyristor switched capacitor (TSC) and thyristor controlled reactor (TCR), and these may be combined with mechanically switched capacitors or reactors to extend the control range. The type of device and its design is generally optimized based on the steady state and dynamic control ranges desired and the required speed of response needed. The most popular form of the SVC consists of a shunt capacitor bank and a variable shunt reactor (TCR). When the reactor is shut off, the reactive power from the capacitors is supplied to the network. As the reactor is switched on, it absorbs the capacitor reactive power, leaving less for the system. A voltage regulator controls the reactor so that the amount of reactive power flowing into the network is the amount necessary to hold the desired voltage. The SVC is a relatively low loss device compared to a synchronous condenser, although losses in the reactor are not insignificant.

As compared to the continuous control of the TCR, thyristor switched capacitors represent a fast form of discrete control. Blocks of capacitors are switched using thyristors. Thus they can be switched quickly and often, without the maintenance concerns of mechanical switched capacitors. The size of the blocks is a compromise between smoothness of control, economics, system requirements, and voltage change upon switching. Within the last five years, there has been application of thyristors to switch reactors is steps, similar to TSC. The discrete switching of blocks of capacitors or reactors has the advantage of the elimination of harmonic production and the need for filters present in TCR.

SVC devices require significant substation space for the capacitors, reactors, filters, and switchgear, a building for the thyristors and controls, and a relatively complex cooling system. They are standard pieces of equipment (although not common) and have been installed in many areas with generally good operating experience.

STATCOM technology is relatively new, and is still developing, although manufacturers are now offering the device. There is one operating STATCOM, but not of the size contemplated here. Another is planned for operation this year in New York State and is for bulk system voltage control. The STATCOM has the advantage of requiring less substation space as it require a much smaller amount of capacitors as compared to a SVC. Reliability is expected to be comparable to that of an SVC, that is, quite good.

4.0 Dynamic Response Characteristics

Static compensation devices have significantly different dynamic response characteristics from those of synchronous condensers. Each has its own advantages.

The reactive output of the synchronous condenser will be very similar to that of the present generators. The units will respond automatically to the system's needs for reactive power by controlling generator terminal voltage within the reactive capability of the units. Excitation systems have significant transient capability and can often go to much higher levels of excitation to, for example, improve system stability. This capability is present in the existing controls, although this author does not know the amount. The limit to the reactive output will be controlled by the maximum excitation limiter that is part of the excitation system. It will limit the field current to the neighborhood of rated field current, which in turn will limit reactive output. The reactive output will, most likely, be relatively independent of voltage, although this depends on the type of excitation system.

The reactive output of an SVC will respond very quickly to system disturbances, faster than the excitation of a typical generator. The design of the SVC determines the total speed of response. For example, if part of the device is mechanically switched capacitors, the response will be somewhat slower. An important characteristic is that when the device is fully on, its characteristic is equivalent to a shunt capacitor (or reactor, if absorbing). Thus its output will vary with the square of voltage. As the limit is likely to be reached only during severe system low voltage problems, the device's output may decrease significantly just when it is most needed. Normally, if continuous control is a requirement, the SVC is kept in controlling range with appropriate mechanical switching of blocks of reactors or capacitors. The design of the SVC requires careful consideration of the amount of required continuously controllable reactive supply and the sizes of switchable components.

The reactive output of a STATCOM, on the other hand, will vary with a constant current characteristic when on limit. Thus its output will vary linearly with voltage. It is thus somewhere between the characteristic of the generator and the SVC when operating on limits. The dynamic response characteristic of a STATCOM will be similar to that of an SVC. It will respond very quickly to system voltage problems.

One other characteristic of the synchronous condenser is that, as a rotating machine, it will supply short circuit current. Thus it will help to "stiffen" the system and have an instantaneous response to system changes such as line switching or large load changes. In some cases this is beneficial; in others where for example breaker interrupting ratings are a concern, removal of some short circuit contribution may be beneficial. Although they are synchronous machines, stability of the synchronous condensers is not a major concern. As there is little power involved, there is no significant imbalance of mechanical and electrical power during faults, and the synchronous condenser will "follow" system swings.

5.0 Costs and Economic Comparison

As noted above, detailed analysis would be required to determine the costs involved in converting the Gannon generators to synchronous condensers. The costs of static compensation are also quite variable. One of the major components of the operating cost for either of the devices would be losses and estimating losses would require an approximation of the amount of reactive power required versus time (duty cycle) which is, at present, not yet quantified. Thus it is not possible to do a full economic comparison of the two alternatives. Here we will simply describe the process and give general comments on the ballpark costs and comparison of the two alternatives.

The economic comparison of the two alternatives would require the inclusion of four components: the equipment purchase cost (first cost), installation costs, power losses, other operating and maintenance costs, and reliability.

The costs of static compensation equipment (first cost, installed) is estimated to be in the range of 55 to 80 $/KVAR. This is based on information gathered on several relatively recent projects and other information from manufacturers. There is a large range in the estimates of cost of such equipment.

The entire amount of reactive power required may not need to be supplied by an SVC or STATCOM. A significant portion could be supplied by banks of mechanically switched capacitors or reactors. The first cost of shunt capacitors is in the order of $8/KVAR. Further studies would be required to determine the amount of reactive power needed, the location of that reactive compensation, and the percentage that would be needed to be supplied by a continuously acting device and the amount that could be supplied by slower, switched capacitors.

The cost of the static starter could be estimated based on the cost of other types of drives. A rough estimate of $65 per KVA was given by one source. This would not include the extensive buswork and switchgear required to get the output of the starter to each of the units and the equipment necessary to transfer the units to the system.

Some other comments on the economic comparison:

The "initial feel" of several knowledgeable experts is that the lifetime costs of the two alternatives would be in the same order of magnitude. However, reliability aspects and operating simplicity of static compensation versus rotating equipment favors the static compensation.

The static compensation, whether SVC or STATCOM, will have significantly higher first cost, but will have much lower maintenance and operating costs. The static compensation will have lower losses while operating at any level of output, but this effect will be even more pronounced at small amounts of reactive output where losses from the static compensation will be very low, while the synchronous condenser will have significant losses even when operating at little reactive power output (due to windage and frictional losses). Full load losses (reactive output of 60% of rated MVA) would be on the order of 2.5 to 3.5 % of rated MVA. This includes the losses in the generator and the step-up transformer. (Full load efficiency of the generators range from 98.2 to 98.9 %, probably not accounting for some mechanical shaft losses. Full load loss in the step-up transformers is probably in the order of 1 to 1.5 %. Full load stator current would be reduced in synchronous condenser operation so that component of loss would be reduced, although other components would be the same). Full load losses for static compensation vary with the type of device. Full load loss for an SVC is typically about 1% of rating. Full load loss for a STATCOM is probably about 2% of rating. The amount of losses in static compensation devices depends on the amount of harmonic filters required and the design of these filters.

SVC or STATCOM installations are normally designed to be unmanned. The equipment is also designed to require little maintenance. The synchronous condenser operation would likely require a staff to maintain the generators, the cooling system, start the units, etc. Some of this might be automated but it is generally thought that the maintenance requirements for the condensers will be significantly more than required for the static compensation.

Reliability is a major concern. Static compensation would be expected to be significantly more reliable than synchronous condensers, for a similar amount of reactive power supply. However, with the potential for conversion of up to six units, reliability of the synchronous condensers could also be addressed by extra capacity.

It would be necessary to determine the expected lifespan of the generators and other equipment to perform an economic comparison. The units are 30 to 40 years old. Future rewinding or repair or replacement of other equipment costs would need to be factored into long range comparisons to static compensation, which would have an estimated lifespan of 20 to 30 years.

In general, synchronous condensers have been applied in areas of the grid where the system was very weak, and the voltage source characteristic of the synchronous condenser (i.e. the ability to supply short circuit current) is very beneficial in strengthening the system. An example of this is the application of high voltage dc (HVdc) converter stations on weak systems, where system strength is critical for the proper firing control of the conversion process. The last major installation of synchronous condensers in North America, that we aware of, was for that reason, and involved three +300/-165 MVAR condensers at the Nelson River HVdc Dorsey terminal in the early 1990's. In other areas, static compensation has generally been applied.

Another general point is that the location of the reactive supply from the synchronous condenser conversion option is limited to the Gannon station. Reactive supply from an SVC or STATCOM could be located at the Gannon station, but could also be located at other substations or split among several substations if studies showed that to be advantageous.

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