THIRTY-SIXTH ANNUAL REPORT

ON THE ELECTRIC PROPERTY

of the

PUERTO RICO ELECTRIC POWER AUTHORITY

SAN JUAN, PUERTO RICO

UNDER TERMS OF TRUST AGREEMENT

Dated as of January 1, 1974, as amended,

to

U.S. BANK TRUST NATIONAL ASSOCIATION

TRUSTEE

JUNE 2009

URS

Washington Division

February 12, 2010

Puerto Rico Electric Power Authority,
San Juan, Puerto Rico 00936 and
U.S. Bank Trust National Association
New York, NY 10005, Trustee under the Trust
Agreement, Dated as of January 1, 1974, as amended

Gentlemen:

We submit herewith our Thirty-sixth Annual Report (for fiscal year 2009) as required of the Consulting Engineers, URS Corporation, under the terms of Section 706 of Article VII of the Trust Agreement governing the Puerto Rico Electric Power Authority's Power Revenue Bonds.

This report includes changes set forth in an Amendment to the Authority's 2009-2010 Budget of Current Expenses and Capital Expenditures. The Amended Budget significantly affects the Authority's financial status regarding Trust Agreement Requirements. The Amendment was prepared by the Authority in January 2010.

Very truly yours,

George W. Romano Jr.
Consulting Group Manager

GWR/gs

URS Corporation
One Canal Park
Cambridge, MA 02141
Tel: 617.621.0740
Fax: 617.621.9739

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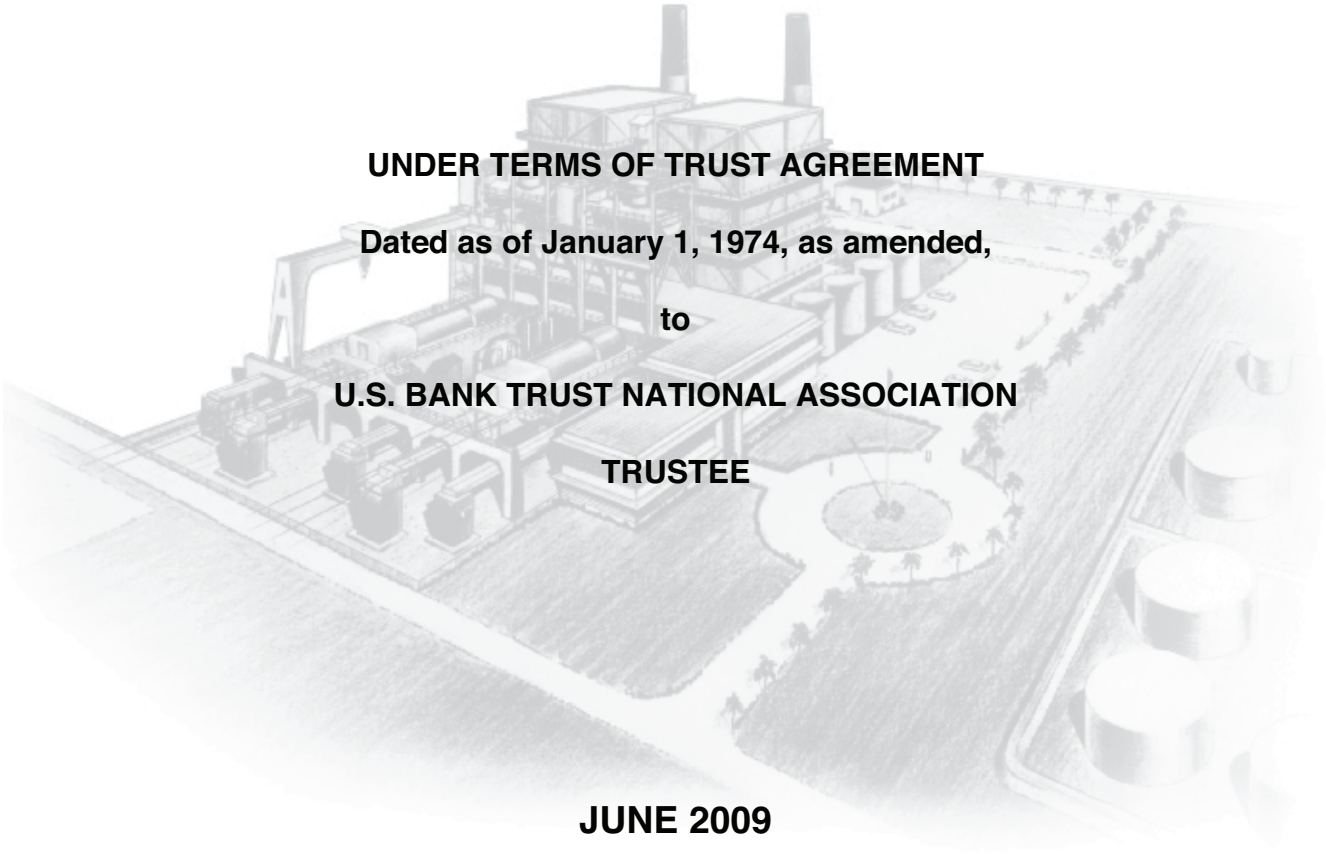

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Washington Division

EXECUTIVE SUMMARY

This report is the 36thAnnual Report by the Consulting Engineers to the Trustee of the 1974 Trust Agreement. The report is based on the Consulting Engineer's inspections, interviews and review of relevant data pertaining to the operation of the Puerto Rico Electric Power Authority electric System during the Authority's fiscal year 2009, ending June 30, 2009.

The Authority's economic performance in fiscal year 2009 was marked by decreasing energy sales in the three largest sectors as the recession in Puerto Rico deepened. Electric power sales in fiscal year 2009 fell 5.5% from the previous year, establishing the second consecutive year of decline. Fiscal year 2009 was the sixth consecutive year during which the rate of growth of the Authority's electric power sales was lower than the preceding year. The Authority's Current Forecast predicts the rate of decline in energy sales will steadily improve over the next three fiscal years, with modest positive growth forecasted for fiscal years 2013 and 2014.

The decline in sales coupled with lower fuel costs in fiscal year 2009 resulted in electric sales revenues that were 8.4% less than the previous year. Net Revenues, as defined by the Trust Agreement, were down 7.6% in the same time frame.

In January 2009 Ing. Miguel A. Cordero López was re-appointed as Executive Director of the Authority; he previously served as Executive Director from 1993 to 2000. Ing. Cordero is a professional electrical engineer with more than 30 years experience with the Authority. During his first tenure as Executive Director he initiated programs that reduced the Authority's dependence on fuel oil by 30%. In addition to his service with the Authority, Ing. Cordero has served in management positions in many public sector agencies and Authorities.

A net additional 600 MW of new capacity went into service during fiscal year 2009. The Authority added 464 MW at the San Juan Steam Plant with the new combined-cycle Units 5 & 6; completion of these units was the culmination of an extended effort which began with the contentious repowering project that stalled early in construction and its subsequent revival by new vendors and contractors. Secondly the Authority replaced four 21 MW combustion turbines at the Mayagüez plant with eight more efficient, aero-derivative combustion turbines totaling 220 MW. All the new combustion turbines placed in service in the past year are capable of firing natural gas as well as distillate oil, to support the Authority's plans for increased use of natural gas when it becomes available at the site.

The major fire damage at the Palo Seco Steam Plant in December 2006 removed 602 MW of generating capacity from the San Juan area load center and reduced the generation operating reserve capacity below margins that the Authority typically has maintained. At the end of fiscal year 2009 three of the Palo Seco units were in service, with Unit 3 scheduled to return in fiscal year 2010. The extended period when the Palo Seco Steam Plant was below full capacity caused the Authority to defer some scheduled maintenance on other steam plants. With the return of the Palo Seco units and the added capacity from San Juan Units 5 & 6, the Authority's schedule shows that for more than 50% of the days in fiscal years 2010 and 2011 one of the four largest steam units will be in scheduled maintenance, three of these are for major overhauls.

The Authority has identified loses of $363.2 million that resulted from the fires at the Palo Seco Steam Plant. By the end of fiscal year 2009 the Authority's insurance carriers had reimbursed the Authority a total of $301.3 million and another $28.1 million was being negotiated.

URS Corporation
One Canal Park
Cambridge, MA 02141
Tel: 617.621.0740
Fax: 617.621.9739

Despite the extended outages of the Palo Seco units, the System continued to perform without major incidents, as the Authority redistributed its generation and that of the cogenerators; the transmission system operation was buttressed by the 230kV eastern loop that had gone into service in fiscal year 2006. In addition, there were no extraordinary events to challenge the system during fiscal year 2009.

In January 2010 the Authority prepared an amended 2009-2010 Annual Budget to address higher fuel costs than had been projected. The amended Annual Budget incorporated higher revenues resulting from the increased fuel costs and from an energy theft recovery initiative, lower projected operating expenses, and modifications to debt financing. The amended budget has aggressively targeted current expenses, less fuel and purchased power, with a 11% cut from the expenditures of the fiscal year 2009. In view of the significant revisions in the amended budget and their affect on the Authority's financial status regarding Trust Agreement requirements, the Consulting Engineers have incorporated the amended budget in the discussions and evaluations within the Financial section and Appendices of this Annual Report.

Expenditures on capital improvement program projects dropped 28.0%, or $186.6 million, from fiscal year 2008 to 2009 as San Juan Units 5 & 6 and the combustion turbines at Mayagüez were completed. The Authority has developed a lean capital expenditure plan for the next five years, with plans to reduce capital expenditures another $130 million in fiscal year 2010, a reduction of $50 million in fiscal year 2011, no change in fiscal year 2012 and $50 million per annum increases in fiscal years 2013 and 2014.

The Authority's fuel diversity program has been active for more than a decade, focusing on reducing its once almost complete dependence on fuel oil for generating power. A privately owned natural gas fired cogenerating plant has been in operation since 2000, followed two years later when a privately owned coal fired cogenerator went into service. During fiscal year 2009 these two plants produced 31% of the system power and demonstrated reliable operation. In fiscal year 2009 the Authority stopped work on a natural gas pipeline project to its 592 MW Aguirre Combined Cycle plant in response to community opposition. The Authority will turn over the unfinished project and material to the Aqueduct and Sewer Authority for construction of a water pipeline to benefit the island's southeast sector. At the end of fiscal year 2009 the Authority was in discussions with the Commonwealth to recover its project costs. The Authority still plans to expand natural gas utilization by pursuing high efficiency natural gas fired generation projects, including private project development. The current scope of the fuel diversity program encompasses more natural gas fired generation, renewables, and coal.

The Authority's total remittances to the Commonwealth for Contributions in Lieu of Taxes (CILT) and Other were $181.4 million in fiscal year 2009, or 29% of the Authority's net revenues for the fiscal year, using the 1974 Trust Agreement accounting. The Authority's fiscal year 2009 CILT remittances were less than their obligations for that fiscal year, consequently the unpaid balance will be paid over the next three years. CILT remittances for fiscal year 2009 included installment payments on unpaid CILT obligations from fiscal years 2007 and 2008. At the end of fiscal year 2009, the outstanding unpaid CILT balance totaled $97.9 million. In addition to CILT, which benefits the municipalities, the Authority also remitted $42.1 million to the Commonwealth for certain subsidies during the fiscal year and $8.9 million for the amortization of the outstanding line of credit used in the settlement of the municipalities lawsuit.

During fiscal year 2009 the Authority increased its lines of credit for interim financing to $1,603.4 million from $1,307.4 million in 2008. Three changes accounted for the $296 million increase: a $96 million line of credit was established for interim financing of capital improvement program projects; a $225 million dollar fuel line of credit was increased to $275 million; and the Authority initiated a $150 mil-

URS Corporation
One Canal Park
Cambridge, MA 02141
Tel: 617.621.0740
Fax: 617.621.9739

lion line of credit with the Government Development Bank for covering collateral on its power revenue bonds that are based on interest basis swaps. At the end of fiscal year 2009, the Authority's outstanding debt on their lines of credit was $90.4 million, or 7.3%, lower than the previous year. The Authority is evaluating paying down a portion of their interim financing debt with some of the proceeds of the next long term financing which is contemplated in the amended annual budget for fiscal year 2010.

The 1974 Trust Agreement obliges the Consulting Engineers to make specific assessments of the Authority's operations and make recommendations for funding of certain funds established under the Trust Agreement. These are discussed in depth in the report and summarized below:

The Consulting Engineers believes the Authority will receive sufficient revenues in fiscal year 2009 with the existing rates to cover current expenses, to make all required deposits in accordance with the 1974 Agreement's dictates and to exceed its 120% debt service coverage requirement. The debt service coverage was 145% in fiscal year 2009 and is forecasted to be 141% in fiscal year 2010 in accordance with the amended annual budget.

In the opinion of the Consulting Engineers, the properties of the System are in good repair and sound operating condition.

The Consulting Engineers reviewed and approved the Authority's Annual Budget of Current Expenses and Capital Expenditures for fiscal year 2010, which was adopted in June 2009. In addition, the Consulting Engineers has reviewed and approved the Authority's amended Annual Budget for 2010, which is scheduled to be adopted in February 2010. The budget for fiscal year 2010 includes the first year of the Authority's five year Capital Improvement Program. In fiscal year 2010 the Authority is projected to make no internally generated contributions to capital expenditures. In fiscal year 2009 the Authority's internal funding of capital expenditures was $4.7 million or approximately 1% of total expenditures. The Consulting Engineers continues to recommend the Authority should pursue as aggressively as practicable an increase in the internal funding

During fiscal year 2007 the Consulting Engineers approved the use of the Reserve Maintenance Fund as an interim source of funds for the recovery of the Palo Seco Steam Plant, with the stipulation that any moneys withdrawn should be replenished using the proceeds from the Authority's insurance coverage within a reasonable timeframe. Net withdrawals during fiscal year 2008 were $48.6 million, leaving the year-end balance of $569,000. During fiscal year 2009 the Authority applied $5 million to an inter-fund loan for the benefit of the Reserve Maintenance Fund. The Consulting Engineers recommends the Authority deposit $5 million to the Reserve Maintenance Fund during fiscal year 2010.

At the end of fiscal year 2009, the Self-insurance Fund's balance was $62.6 million. During fiscal year 2007 the Consulting Engineers approved the withdrawal of monies from the Selfinsurance Fund to cover uninsured losses associated with the Palo Seco Steam Plant fires. The Authority withdrew $25.4 million from this fund and deposited $5 million during fiscal year 2008; in fiscal year 2009 the Authority deposited $10 million. Based on the current funding levels, the Consulting Engineers recommends the Authority deposit $10 million to the Self-insurance Fund during fiscal year 2010.

URS Corporation
One Canal Park
Cambridge, MA 02141
Tel: 617.621.0740
Fax: 617.621.9739

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230 & 115 KV TRANSMISSION SYSTEM MAP

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INTRODUCTION

This is the Thirty-sixth Annual Report by the Puerto Rico Electric Power Authority's (Authority) Consulting Engineers, URS Washington Division (Consulting Engineers), filed to comply with the provisions of Section 706 of Article VII of the Trust Agreement, dated as of January 1, 1974, as amended and supplemented, between the Authority and U.S. Bank Trust National Association, the successor Trustee for the 1974 Trust Agreement.

Act No. 83 of the Legislature of Puerto Rico, approved May 2, 1941, as amended, reenacted and supplemented (the "Authority Act"), created the Authority a body corporate and politic constituting a public corporation and governmental instrumentality of the Commonwealth of Puerto Rico. Hereinafter, we will refer to Act No. 83 of the Legislature of Puerto Rico, approved May 2, 1941, as amended, reenacted and supplemented as the Authority Act.

With the release of the 1947 Trust Indenture on June 9, 1996, the 1974 Trust Agreement, dated as of January 1, 1974, as amended and supplemented, became the sole document governing all of the Authority's long-term financings, with the exception of minor subordinated interim debt. Throughout this report we will refer to the 1974 Trust Agreement, dated as of January 1, 1974, as amended and supplemented, as the 1974 Agreement.

Section 706 of the 1974 Agreement provides the following:

> *It shall be the duty of the Consulting Engineers to prepare and file with the Authority and with the Trustee on or before the 1st day of November in each year a report setting forth their recommendations as to any necessary or advisable revisions of rates and charges and such other advices and recommendations as they may deem desirable. After...the release of the 1947 Indenture, it shall be the duty of the Consulting Engineers to include in such report their recommendations as to the amount that should be deposited monthly during the ensuing fiscal year to the credit of the Reserve Maintenance Fund for the purposes set forth in Section 512 of this Agreement, deposited during the ensuing fiscal year to the credit of the Self-insurance Fund for the purposes set forth in Section 512A of this Agreement, if any, and deposited during the ensuing fiscal year to the credit of the Capital Improvement Fund for the purposes set forth in Section 512B of this Agreement.*
>
> *The Authority further covenants that the Consulting Engineers shall at all times have free access to all properties of the System and every part thereof for the purposes of inspection and examination, and that its books, records and accounts may be examined by the Consulting Engineers at all reasonable times.*

This Annual Report is based, in part, upon our knowledge of the Authority's operations gained over the more than 60 years that we (Consulting Engineers and its antecedent companies) have been retained as Consulting Engineers. We were initially retained in accordance with the provisions of Section 704 of Article VII of the Authorizing Resolution, dated January 1, 1944, and subsequently in accordance with Section 704 of Article VII of the 1947 Trust Indenture from its inception until its release, a period of 53 years. We have also served as Consulting Engineers in accordance with Section 706 of Article VII of the 1974 Agreement since its inception.

Each year, in fulfilling our duties as Consulting Engineers, we visit and note the condition of all the steam production facilities a minimum of three times; all the remaining production facilities at least once each year; one-third of the more than 380 distribution substations and transmission centers; and a representative cross-section of all additional property owned and operated by the Authority. We regularly review the Authority's various reports and records, meet with the Authority's management and staff to discuss present operations and future plans, and perform a number of analyses relying primarily on data and information provided by the Authority. We also participate in all regular bond issue financings undertaken by the Authority by assisting in the preparation of the Official Statements, by providing several signed Engineers Certificates, and by participating in bond rating agency presentations.

SYSTEM DESCRIPTION

The Authority's System supplies virtually all of the electricity consumed in Puerto Rico and the smaller islands of Vieques and Culebra. The Authority generates approximately 70% of the electricity itself and purchases the remaining from two cogenerators, EcoEléctrica, L.P. located in the Municipality of Peñuelas and AES-PR located in the Municipality of Guayama. During fiscal year 2009, which ended on June 30, 2009, the System served more than 1,458,000 clients.

The Commonwealth of Puerto Rico is the easternmost of the islands comprising the Greater Antilles and is approximately 110 miles in length and 35 miles north to south. Central mountain ranges with peaks as high as 4,390 feet extend the length of the island from east to west. Coastal lowlands formed by the erosion of the central mountains extend inwards on the north coast for 8 to 12 miles and for 3 to 8 miles in the south. The northern coastal lowlands are humid while those on the south side of the island are semi-arid. The island's population density is high; approximately 70% of the island's 3.9 million inhabitants are concentrated in five urban areas—San Juan, Caguas, Arecibo, Ponce, and Mayagüez. Many of the remaining inhabitants populate the many small towns located in the remote mountainous interior. Taken together Puerto Rico's geography, climate, and the dispersion of its clients within the Commonwealth present the Authority with many challenges as it designs, builds, operates, and maintains its System. The Authority serves its clients in 26 districts through seven regional offices, each of which incorporates a technical office.

Puerto Rico is in the path of many of the tropical storms and hurricanes that cross the Greater Antilles during the hurricane season, which runs from June through November. The Authority's transmission and distribution systems, more than 90% of which are above ground, are particularly vulnerable to the high winds, torrential rains, and erosion that are associated with tropical storms and hurricanes. The last hurricane to drastically affect both the island's economy and the System, Hurricane Georges, struck the island on September 28, 1998.

An electric power system is made up of production, transmission, distribution, communication and ancillary facilities, not all of which are physically connected, operated as a single integrated whole. The flow of electricity within the system is maintained and controlled by a dispatch center. It is the responsibility of the dispatch center's operators to match the real-time supply of electricity with the simultaneous demand for it. In order to carry out their responsibilities the System's dispatchers are authorized to buy power to complement the System's own generation and to economically dispatch it based on System requirements.

The Authority's primary dispatch center, which is under the direction of the Director of Generation, Transmission & Distribution, is located at Monacillos, approximately seven miles south of metropolitan San Juan. A Supervisory Control and Data Acquisition (SCADA) system, an integral part of the dispatch center's control system, has the ability to control total load flow on the island and can remotely control many of the Authority's substations and all of the large generating units. A secondary dispatch center is located in Ponce. Both centers are fully staffed during System emergencies, coordinating all restoration efforts.

The three major components of the System are the Production Plant, the Transmission system, and the Distribution system. They account for approximately 81% of the $9.3 billion Plant-in-Service investment. Below is a brief description of each of these components.

The production plant's generating capacity, to the nearest megawatt, is 4,903 MW comprised of 2,892 MW of steam-electric capacity, 846 MW of combustion-turbine capacity, 1,056 MW of combined-cycle capacity, 100 MW of hydroelectric capacity, and 9 MW of diesel capacity. The 2,892 MW of steam-electric capacity consists of 14 units at four sites: Palo Seco–602 MW (four units) and San Juan–400 MW (four units), both on the north side of the island; Aguirre–900 MW (two units) and Costa Sur–990 MW (four units), both on the south side of the island. The reduction in the capacity and number of units at Costa Sur reflects the removal from service at the end of fiscal year 2008 of its Units 1 & 2 which had a combined capacity of 100 MW. The Authority's 1,056 MW of combined-cycle capacity is comprised of two units at the Aguirre complex with a capacity of 592 MW and two units located in the San Juan Station with a total capacity of 464 MW, which came into service during fiscal year 2009. The 846 MW of combustion-turbine capacity consists of 29 units at nine sites around the island, the three-unit 248 MW Cambalache Station being the largest. The 100 MW of hydroelectric capacity consists of 21 units at 11 sites around the island, the 25 MW Yauco No. 1 being the largest unit. The Authority has two

diesel generators each with 3 MW of capacity on standby reserve on the island of Vieques. On the island of Culebra four diesel generators having a combined capacity of 2 MW provide standby reserve. The Authority has mobile a diesel unit capable of generating 1 MW.

During fiscal year 2009 ten units came into initial service and four simple cycle combustion turbines were retired; these changes are reflected in the data above. The two largest new units were San Juan Units 5 & 6 combined cycle units, each having a design capacity of 232 MW. At Mayagüez four 21 MW combustion turbines were retired and removed from the site and replaced by eight aero-derivative simple cycle combustion turbines. The replacement combustion turbines increased the available capacity at the Mayagüez station from 84 MW to 220 MW.

The Authority's Sabana Llana battery energy storage system was designed to provide up to 20 MW for power factor correction and reserve capacity, however, the battery system has not been available for service since fiscal year 2006.

To supplement its own capacity, the Authority purchases power from two cogenerators under the terms and conditions of Power Purchase Agreements (PPA's). The Authority is in the ninth year of a 22-year PPA for 507 MW of gas-fired capacity from EcoEléctrica, L.P. The Authority is in the sixth year of a 25-year PPA for 454 MW of coal-fired capacity from AES-PR. The 961 MW of capacity provided by the cogenerators brings the total capacity available to the Authority to 5,864 MW. (See *Appendix VIII, System Capability.*)

The Authority's transmission system is an interconnected network of 230, 115, and 38 kV power lines that carry electrical power from the production plants to various distribution centers from where it is distributed to clients for consumption.

At the close of fiscal year 2009, the transmission system was comprised of 2,419 circuit miles of lines: 364 circuit miles of 230 kV lines, 691 circuit miles of 115 kV lines, and 1,364 circuit miles of 38 kV lines. Included in the transmission system totals are 24.7 miles of underground 115 kV cable, 59.8 miles of underground 38 kV cable and 54.7 miles of 38 kV submarine cable. The 30 transmission switchyards located at the power plants and the 48 transmission centers located throughout the System have a total transformer capacity of 18,423 MVA. The transmission system includes 68 sectionalizer facilities with automatic air-break switches to protect the transmission network.

As of June 30, 2009, the Authority's distribution system consisted of approximately 31,156 circuit miles of distribution lines (with operating voltages ranging from 4.16 to 13.2 kV) and 333 substations (with a total installed capacity of 4,840 MVA). The distribution system has 1,842 circuit miles of underground lines. There are 795 privately owned substations (with a total installed capacity of 3,168 MVA). The distribution system also includes approximately 1,458,000 client meters.

SYSTEM'S OPERATIONS

PRODUCTION PLANT

The Authority continues its commitment to an ongoing, long-term program to extend the life and to maintain the high level of availability of its production plant, i.e., generating units. The program consists of three components: formal operator training, comprehensive preventative maintenance, and design modification. The formal operator training part of the program emphasizes safety, operating efficiency, and equipment integrity. The comprehensive preventative maintenance part of the program requires the Authority to remove all major generating units from service for maintenance at regularly scheduled intervals to ensure their reliability. These intervals are referred to as "scheduled outages" in the text of this Annual Report. A residual life assessment of critical components is an integral part of the Authority's preventative maintenance practices.

The design modification part of the program represents the Authority's commitment to improve the operation of its generating units by installing redesigned, improved components, or by undertaking conversions. Examples of design modifications include original equipment manufacturer's, OEM, upgrades of the eight 50 MW combustion turbines and of their conversion to dual fuel firing capability, either natural gas or distillate. The control systems in the Authority's sixteen 21 MW combustion-turbines are being upgraded as part of a broader ongoing capital program. The Authority also converted all of its "forced draft" thermal plant boilers to "balanced draft" operation. These modifications allow the equipment to be operated at design or increased capacity with greater operational efficiency and reliability.

Among the Authority's current projects are those that aim to increase the efficiency of its steam turbines by improving the performance of the associated condenser. These projects have included: retubing condensers; replacing condenser vacuum equipment; replacing cooling water filtration systems, and improving condenser backwash capabilities. The Authority has installed continuous condenser cleaning systems on several units; these vendor owned continuous condenser cleaning systems are operated on a pay-for-performance basis. Turbine efficiency is also being improved through the installation of high efficiency seals, through turbine control upgrades, and through the installation of redesigned turbine blades.

We visit all the steam-electric production facilities a minimum of three times each year and all of the remaining production facilities at least once each year. We examine numerous operations reports and we regularly meet with the Authority's management and staff to discuss present operations and future plans.

In accordance with an agreement approved by the Secretary of the Puerto Rico Department of Labor, Puerto Rico's Jurisdictional Boiler Inspector has allowed the Authority to increase the interval between boiler certifications from 12 months, as normally required by Commonwealth law, to 18 months. At the end of fiscal year 2009 the Jurisdictional Boiler Inspector had certified all of the Authority's boilers within the previous 18 months.

MAINTENANCE

As is common in the electric utility industry, expenditures associated with some maintenance projects are capitalized rather than charged as a current maintenance expense. Occasionally the Authority installs capitalized components during a scheduled environmental outage. Significant production plant upgrades or design modifications are implemented during a major overhaul. The costs associated with these projects are capitalized and the replaced units of property are retired from service. Maintenance activities, routine and those performed during an outage, are charged against the plant's maintenance budget. During scheduled outages the Authority performs non-destructive testing (NDT) examinations of representative critical components to establish their condition and perform or schedule appropriate repair work. The scope of NDT examinations include boiler pressure parts, power piping, steam turbine components, electrical generators, transformers, and switchgear.

The Authority schedules their fourteen steam-electric generating units out of service for an environmental outage of two to four weeks duration at intervals of twelve to eighteen months. During an environmental outage the boiler and other components are cleaned to meet the requirements of the Air Compliance Preventative Maintenance Schedule contained in the Authority's Consent Decree with the Environmental Protection Agency (EPA). The Authority may keep a unit in service up to an eighteen-month limit subject to the unit's compliance with the emissions criteria in the Consent Decree. Frequently the Authority will advance the start of an environmental outage to ensure that adequate capacity is available during a period of high demand or to

avoid having several units out of service concurrently. The following paragraph describes some of the cleanings, inspections, and replacements that the Authority performs during an environmental outage.

At the start of an environmental outage slag is removed from the boiler and the water walls are cleaned. The superheater, reheater, air heater, and economizer areas are washed and inspected, as are the exhaust gas ducts and the stack. Air heater components; seals, baskets, casing, and sector plates are inspected and replaced as necessary. Ductwork is repaired. Hoppers are emptied and cleaned, expansion joints are inspected for corrosion and leakage. Fuel handling equipment is inspected, repaired, and recalibrated as necessary. The forced and induced draft fans and the gas recirculation fan are cleaned, noise and vibration levels monitored, adjustments made and repairs completed. Motors for fans and main boiler pumps are cleaned and inspected. Dampers are inspected and adjusted. The windbox, burners, combustion air instrumentation, combustion controls, and soot blowers are inspected and damaged or worn components are either repaired or replaced. Monitors for opacity, oxygen, and furnace pressure are cleaned, recalibrated, or as necessary replaced. Pumps, feedwater heaters, the deaerator, and associated valves are inspected. Lubricating oil systems are inspected. Power transformers are inspected and breakers tested and adjusted. If a pressurized part of the boiler has been replaced the boiler part will be pressure tested before the unit returns to service. Life extension inspections and NDT activities are completed on critical systems and components in preparation for future programmed outages.

In the discussions regarding the status of production units that follow, the narrative will note the duration of a unit's environmental outage and describe work completed during the outage, which is in addition to that routinely performed during an environmental outage.

Thirteen of the Authority's fourteen steam-electric generating units were in service during fiscal year 2009. Palo Seco Unit 3 was not in service as the restoration from damages incurred during the December 2006 station fire was continuing at the end of fiscal year 2009. Twelve of the 13 steam-electric generating units that were in service during fiscal year 2009 underwent an environmental outage during the fiscal year. Four of the environmental outages were completed while the unit underwent a programmed major overhaul. During fiscal year 2009 one of the 13 in-service steam-electric generating units was in service more than 18 months between environmental outages. The maintenance interval was extended because of System operational considerations caused primarily by the unavailability of the capacity from the two large Palo Seco units. The Authority notified the EPA of the need to keep the unit in service prior to the month in which it went beyond the Consent Decree's 18-month interval. The unit was operated in an environmentally compliant manner during the extended period.

With few exceptions the Authority sequences scheduled outages so that the large steam electric units are available for service from May through November, the months of maximum demand. This strategy seeks, to the extent possible, to maximize the availability of the System's capacity while maintaining compliance with the Consent Decree with the EPA.

Steam turbines are internally inspected every five-to-seven years. This work, which is typically scheduled for a period of three-to-five months duration, includes opening the high-, intermediate-, and/or low-pressure section of the steam turbine and disassembling, repairing, or replacing major components; the scope of work is more comprehensive than an "environmental outage". It is identified as a "major overhaul" in the descriptions of the status of production units that are discussed below. Occasionally the scope of work performed during a major overhaul will cause the schedule to be extended beyond the three-to-five months required to complete the turbine work. These events are detailed in the unit descriptions that follow.

The Authority's remaining production plant also includes both simple cycle and combined-cycle combustion-turbines, and a number of relatively small hydroelectric plants.

The Authority schedules maintenance on its 39 combustion-turbines (29 operated in simple cycle configuration and ten operated in combined-cycle configuration) based upon the number of "equivalent fired hours" of operation as specified in manufacturers' manuals. The equivalent fired hours concept takes into account the wear and tear associated with starting up the units as well as other operating factors that reduce the actual number of hours that units can be run between inspections. Eighteen of the Authority's simple cycle combustion-turbines are 21 MW Frame 5 machines, located at seven sites throughout the island. During the 1990's the Authority improved the performance of these combustion turbines by upgrading them to model "PA"

configuration. One of the benefits of the "PA" modernization is that the interval between certain inspections increased the equivalent fired hours as follows: fuel nozzles of these units are inspected every 1,125 equivalent fired hours or 2,250 equivalent fired hours for units with air atomization; combustion section inspections are conducted every 4,500 equivalent fired hours; and intermediate inspections are conducted every 9,000 equivalent fired hours. Compressor and power turbine sections are rebuilt during major overhauls, which are scheduled every 18,000 equivalent fired hours. Beginning in 2004 the Authority began a program to replace certain components in each of the 21 MW combustion turbines. The program included the replacement of the ratchet and torque converter thereby improving starting reliability, the installation of a universal fuel system, turbine modifications, an upgrade of the turbine control system, and new digital controls for the excitor. These upgrades have been completed on 13 of the 18 combustion turbines. The upgrades to the remaining combustion turbines are scheduled for completion in fiscal year 2012. Vibration analysis, lubricating oil analysis, and other diagnostic tests are performed monthly.

During fiscal year 2009 these units underwent programmed maintenance inspections and, as described in the *Other Combustion-Turbine Power* section of this report, underwent substantial upgrade to improve their efficiency and reliability

Eight new FT8 aero-derivative simple cycle combustion turbines went into service at the Authority's Mayagüez plant during fiscal year 2009. These eight combustion turbines comprise four units. The combustion turbines are connected in opposed pairs, between each pair is a 55 MW generator. The four units are capable of 220 MW; they replace the four 21 MW combustion turbines that were previously sited at the Mayagüez plant. The new units will be inspected and maintained at the following intervals:

> "A" Inspection the sooner of every 1,000 hours or annually, during which borescope inspections are performed and preventative maintenance completed under the direction of a technical advisor.
>
> "B" Inspection performed every 12,500 hours is a hot section inspection of the combustors, the power turbine sections and the seals and bearings. The unit is disassembled and shipped to a shop for the inspection.
>
> "C" Inspection performed at 25,000 hours includes the inspection and refurbishment of the combustion turbine's intermediate case, the bearing compartments, pumps, in addition to the components inspected during a "B" inspection.
>
> "D" Inspection performed at 50,000 hours entails the shop inspection of all sections of the combustion turbine and the refurbishment or replacement of worn components.

The three 82.5 MW Model GT 11N combustion-turbines power blocks at the Cambalache Combustion-Turbine Station are inspected and maintained in accordance with the schedule below:

> Class "A" Inspection every 4,000 equivalent fired hours: the combustor, burners, and turbine blades are inspected; the duration of the inspection is approximately 6 days.
>
> Class "B" Inspection every 8,000 equivalent fired hours: the instrumentation is recalibrated; the combustor, burners, and turbine blades are inspected; and the once-through steam generator (OTSG) is washed; the duration of the work is approximately 6 days.
>
> Class "C" Inspection every 16,000 equivalent fired hours: the blades in the compressor section are replaced; the combustor is removed for inspection; the combustor liner is replaced; thermal tiles and holding rings are replaced; the turbine is opened; the first three rows of blades in the high-pressure section of the turbine are replaced; auxiliaries are inspected and repaired as necessary; the duration of the work is approximately 31 days. The removed combustor liner and turbine blades are refurbished for use during future outages.

The Authority completed the upgrade of the last of the Frame 7 combustion turbines at the Aguirre Combined Cycle Station to a modified Frame 7EA design during fiscal year 2007. The upgrade allowed the Authority to increase the number of equivalent fired hours a combustion turbine is in service between scheduled maintenance inspections to the hours cited below:

> Combustion inspections during which burner nozzles, check valves, filters, and associated instrumentation are inspected are scheduled every 5,300 equivalent fired hours. Prior to the design upgrade combustion inspections were

performed at 4,000 equivalent fired hours intervals. Combustion outages take less than a week.

Hot-gas-path inspections, during which the liner, the first stage turbine blades, rotor bearings, burners, etc., are inspected, are scheduled approximately every 15,900 equivalent fired hours. The turbine inspection ports are opened; turbine blades are replaced as dictated by the degree of blade corrosion. A hot-gas-path inspection is typically completed over an eight-week period.

Major overhauls, during which the turbine and compressor are opened and blades in the first stage of the turbine are replaced, are scheduled after 31,800 equivalent fired hours. In addition, reduction gears and other turbine components and auxiliaries are inspected and repaired. Duct sections, baffles, the exhaust stack, the generator, and other electrical equipment are also inspected and repaired. Filter media in the air intake system are also replaced at this time. A major overhaul is typically completed over a sixteen-week period.

The steam turbines of the Aguirre combined-cycle plant are maintained in accordance with the same guidelines as those followed for the 16 steam-electric turbines.

During October 2008 the Authority's two 232 MW combined-cycle units, San Juan Units 5 & 6, went into commercial service. Each unit is comprised of a single combustion turbine with a capacity of 165 MW and a steam turbine with a capacity of 67 MW. The Authority has signed a long term service agreement, LTSA, with the combustion turbine vendor of approximately eight years duration during which the vendor will be responsible for the maintenance of the combustion turbine generator and the steam turbine generator. The Authority will be responsible for the maintenance of the combined-cycle plant's auxiliaries. Combustion turbine inspections will be performed on the basis of equivalent operating hours, EOH, as follows:

8,000 EOH—Modified Combustion Inspection fuel nozzles, combustor baskets, transition pieces, turbine blades in rows 1, 2, 3, and 4, and turbine vane and ring segments in rows 1 and 2 will be replaced. Inspections of the inlet, compressor, turbine, and exhaust sections of the combustion turbine are completed.

16,000 EOH—Combustion Inspection fuel nozzles, combustor baskets, transition pieces, turbine blades in rows 1, 2, 3, and 4, and turbine vane and ring segments in rows 1 and 2 will be inspected and replaced as necessary. Inspection of the inlet, compressor, turbine, and exhaust sections of the combustion turbine are performed.

24,000 EOH—Major Inspection of the Combustion Turbine is completed with inspection and replacement of blades in the compressor section and in the turbine section.

Steam Turbine Generator inspections will be performed on the following frequencies:

Steam Turbine Generator Valve Inspections will be performed every 18 months. The scope includes the cleaning, NDE, and adjustment of HP stop and control valves, reheat stop valves, and intercept valves.

Major Inspections of the Steam Turbine Generator are performed every 50,000 EOH.

The Authority has significantly reduced the duration of unscheduled outages of some of its large generating units by maintaining an inventory of critical spare components. On a long-term basis this practice has contributed to the improvement of both unit and System availability. Refer to the *Spare Components* section below for a listing of the major spare components.

The hydroelectric generating units are inspected on an annual basis and opened every five years.

Maintenance expenditures outlined below do not include the cost of the new capitalized units of property, and therefore they do not completely reflect the Authority's total cost of maintaining its fixed assets. As shown in *Appendix III, Detail of Operating and Maintenance Expenses,* maintenance expenditures for the production plant for fiscal year 2009 totaled $117.3 million. Expenditures for fiscal years 2010 through 2014 have been projected to be $122.5 million, $114.9 million, $114.7 million, $114.4 million and $114.2 million, respectively.

STATUS OF PRODUCTION UNITS

The statuses of the Authority's production units are described in the following sections based on their condition as of the week of June 30, 2009.

The table below provides a brief profile of each unit (capacity data, age, annual heat rate, and annual equivalent availability). The annualized heat rate is a measure of a unit's operating efficiency, which can be affected by its level of dispatch and other factors, such as capacity limitations caused by out of service equipment or sub-systems. Since heat rate is measured in terms of required fuel heating value input to produce one kilowatt of power, better performance is indicated by a lower heat rate.

Annual equivalent availability is defined as the percentage of time a generating unit was available, at its rated capacity, for service in a rolling 12-month period. For this Annual Report, that period was the fiscal year ended June 30, 2009. The equivalent availability of the Authority-owned production plant for fiscal year 2009 was 71.4%. The two factors that weighed most heavily on the 2009 equivalent availability factor were continuing difficulties related to the return to service of the large Palo Seco steam units and the introduction of San Juan Units 5 & 6 which experienced routine and non-routine service interruptions during their first year of service. With those exceptions the Authority's large steam units continued their recent performance by maintaining good reliability levels and achieving a better heat rate during fiscal year 2009 than in the prior fiscal year.

A summary of annual performance data for each unit is presented on the table below:

AUTHORITY'S PRODUCTION PLANT SUMMARY PERFORMANCE FISCAL YEAR 2009

	RATED CAPACITY	AVAILABLE CAPACITY	INITIAL OPERATION	ANNUAL HEAT RATE	ANNUAL EQUIVALENT AVAILABILITY
STEAM PLANTS					
Aguirre Unit 1	450	450	1971	10,330	80%
Aguirre Unit 2	450	450	1971	10,186	93%
			Aguirre Station	10,284	87%
Costa Sur Unit 1 *Removed from service 4/30/08*	50		1957		
Costa Sur Unit 2 *Removed from service 4/30/08*	50		1958		
Costa Sur Unit 3	85	85	1960	11,745	66%
Costa Sur Unit 4	85	85	1962	12,007	80%
Costa Sur Unit 5	410	390	1969	10,664	80%
Costa Sur Unit 6	410	0	1972	10,644	88%
			Costa Sur Station	10,806	78%
Palo Seco Unit 1	85	85	1959	10,872	88%
Palo Seco Unit 2	85	85	1959	10,905	89%
Palo Seco Unit 3	216	0	1967		0%
Palo Seco Unit 4	216	120	1968	10,395	18%
			Palo Seco Station	10,819	31%
San Juan Unit 7	100	100	1964	11,248	75%
San Juan Unit 8	100	100	1964	11,469	88%
San Juan Unit 9	100	100	1966	11,444	88%
San Juan Unit 10	100	0	1965	11,639	32%
			San Juan Station	11,415	71%

AUTHORITY'S PRODUCTION PLANT SUMMARY PERFORMANCE FISCAL YEAR 2009 *continued*

	RATED CAPACITY	AVAILABLE CAPACITY	INITIAL OPERATION	ANNUAL HEAT RATE	ANNUAL EQUIVALENT AVAILABILITY
COMBINED CYCLE UNITS					
Aguirre Combined Cycle Unit 1	296	202	1976		61%
Combustion Turbine 1-1	50	0		14,028	23%
Combustion Turbine 1-2	50	50		15,596	25%
Combustion Turbine 1-3	50	50		13,130	96%
Combustion Turbine 1-4	50	50		12,396	64%
Steam Turbine 1	96	52			80%
Aguirre Combined Cycle Unit 2	296	150	1975		63%
Combustion Turbine 2-1	50	50		12,897	94%
Combustion Turbine 2-2	50	50		13,114	97%
Combustion Turbine 2-3	50	50		12,915	92%
Combustion Turbine 2-4	50	0		13,188	17%
Steam Turbine 2	96	60			39%
		Aguirre Combined-Cycle Plant		11,568	62%
San Juan Unit 5	232	0	2009	8,394	31%
San Juan Unit 6	232	225	2009	7,951	58%
COMBUSTION TURBINES					
Cambalache CT Power Blocks					
CCTP 1	82.5	82.5	1997	11,884	94%
CCTP 2	82.5	82.5	1997	12,155	88%
CCTP 3	82.5	82.5	1998	11,980	89%
			Cambalache CTs	11,995	90%
Frame 5 GT Power Blocks					
9 Blocks of 2 GT's	378	336	1971 - 1973	14,411	85%
Mayagüez					
GT 1	55	27.5	2009	10,206	90%
GT 2	55	55	2009	10,097	98%
GT 3	55	55	2009		98%
GT 4	55	55	2009		97%
				ANNUAL SERVICE FACTOR	**ANNUAL EQUIVALENT AVAILABILITY**
HYDRO					
Total for 21 Hydro Units	100	78.6	1929 - 1953	23%	92%
DIESEL GENERATORS					
Total for 7 DG sets	9	9	1980 - 2006	0.70%	99%

Steam-Electric Production Plant

Total Generating Capacity 2,892 MW

The generating units within a steam-electric generating station are identified by acronyms in the following manner: Unit No. 1 in the Aguirre Steam Plant is introduced as ASP Unit No. 1; Unit No. 3 at Costa Sur Steam Plant is CSSP Unit No. 3, and so on. The narratives on the generating units in this section present information by paragraph in the following sequence:

The first paragraph provides historical and annualized operational data and summarizes the types and number of outages the unit experienced during the fiscal year. In this paragraph and in the following paragraphs turbine sections are identified in the following manner: high-pressure (HP), intermediate-pressure (IP), and low-pressure (LP).

The second paragraph describes the number and types of scheduled outages (major overhaul, environmental outage, or maintenance outage) the unit experienced during the fiscal year. The work performed during maintenance outages is described if the outage was longer than 24 hours. However, if a unit was scheduled out of service repeatedly for the same reason, the cause of the maintenance outages and their resolution will be noted regardless of the brevity of the outage.

The third paragraph describes the number of times and the duration of forced outages and unit limitations the unit experienced during the fiscal year. The cause of the outage or limitation and the action(s) taken to return the unit to full service is described when the forced outage or limitation was of more than 24 hours duration. Repeated outages or limitations attributed to the same cause are noted, despite being of less than 24 hours duration. The Authority tracks unit limitations as "equivalent outage hours" (EOH), which are a measure of the hours the unit's output was restricted below full capacity; for example, operating for 24 hours while the unit output is limited to 50% is equivalent to 12 hours of outage for the unit at full capacity.

The fourth paragraph notes the scheduled outages that are planned for fiscal year 2010 or beyond along with equipment and system replacements and upgrades that are included in the Capital Improvement Program. Capital expenditures for station services that impact a number of the station's units are described in the station's Unit 1 narrative. The date of the most recent and the scheduled start of the unit's next major overhaul are noted.

Aguirre Steam Plant

ASP Unit No. 1 was on line, capable of full output. The unit's reliability was impacted by a number of events during the fiscal year. Aguirre Unit 1 returned to service on completion of a six-week extended environmental outage in December 2008. In addition to that outage the unit was scheduled from service five times for maintenance; these maintenance outages kept the unit from service for ten days. This unit was forced from service on five occasions; these events kept it from service for approximately nine days. During the year the unit accrued a total of 248 equivalent outage hours. At the end of the fiscal year this unit had generated an average of 322.8 MW and had a gross capacity factor of 59.6%. Unit 1 was in service 7,280 hours during the fiscal year.

The Authority scheduled Unit 1 from service in early November at the start of a 43-day extended scope environmental outage. In addition to the work completed during routine environmental outages the Authority also reconditioned the LP turbines, replaced 448 dissimilar metal welds in the superheater, installed inspection viewing ports on switchgear, replaced a shaft on a forced draft fan, adjusted the servos, and chemically cleaned the condenser. Two maintenance outages within a ten day period were needed to repair boiler tube leaks, these repairs were completed within seven days and the unit returned to service early in October. A leak at a turbine bearing was repaired during a five day scheduled outage in January. In March a two day maintenance outage was needed for the repair of boiler tube leaks and in late March the Authority repaired an oil leak in a normal station service transformer (NSST).

Forced outages kept the unit from available status for approximately ten days during fiscal year 2009. The failure of excitor brushes caused the unit to trip twice. Following one of these trips tubes in the superheater area broke, their repair was completed over the following three days. An electrical problem at a forced draft, FD, fan forced the unit out of service in October. In November the Authority replaced parts of the turbine drive boiler feedwater pump and the repaired broken boiler tubes during a forced outage. The unit's output was limited for the equivalent of ten days of generation at its rated capacity of 450 MW. Eight of the equivalent outage days accrued

while the Authority completed weld repairs to the shaft of one of the unit's two FD fans.

Unit 1 is scheduled to begin a major overhaul in January 2010. During the major overhaul waterwall sections will be replaced as will the windbox and boiler corners. A section of the superheater will be replaced. The condenser will be cleaned, the HP/IP turbine rotor will be replaced and the HP casing repaired. The generator and turbine drive boiler feed pump (BFP) will be cleaned and inspected. A motor on the start-up BFP will be replaced. Preventative maintenance will be performed on electric motors and transformers. Relays will be tested and reset. During fiscal year 2009 the Authority upgraded the fire detection and suppression systems at the station. When the last phase of the upgrade is completed in August 2009 the following systems will be operational: a foam system in the tank farm area, a water spray system will protect boiler corners, air heaters, lube oil tanks, turbine bearings and couplings, an FM 200 system will protect personnel and equipment from fire in enclosed spaces like the DCS room, the excitor room, servers and communication rooms and the control room. Other capital expenditures were dedicated to the refurbishment of critical equipment and to the replacements that will be installed during the overhaul described above.

Both Aguirre units are capable of regulating frequency between 230 and 430 MW. The Aguirre Steam Plant had the lowest net heat rate and the lowest percent of auxiliary energy consumption of the four largest steam electric generating stations.

ASP Unit No. 2 was on line capable of full output. During fiscal year 2009 the unit's availability was impacted by a number of planned and unplanned events, the sum of which kept it from available status for a total of 26 days. This unit was in service more hours, 8,159, during the fiscal year than any of the Authority's other steam electric units. Eight scheduled maintenance outages kept the unit from available status for 21 days. The unit was forced from service six times, these forced outages kept it from available status for a total of six days. During fiscal year 2009 Unit 2 generated an average of 326.7 MW, achieved a capacity factor of 74.2%, and was capable of regulating frequency.

Unit 2 completed an environmental outage late in fiscal year 2008 and was not scheduled for an environmental outage during fiscal year 2009. The Authority repaired boiler tube leaks during four maintenance outages, these repairs accounted for seven of the 21 days that the unit was unavailable while undergoing maintenance. During October the Authority scheduled the unit from service for approximately four days during which the air heaters were cleaned and repaired and the boiler back pass washed. Feedwater heaters were repaired during two maintenance outages; together these outages accounted for six of the maintenance outage days. Late in the fiscal year the unit was scheduled from service twice for maintenance. The main power transformer was inspected, and the transformer oil replaced during a four-day maintenance outage from which the unit returned to service in early June. During the last of the maintenance outages the Authority repaired a flow control valve.

The unit was forced from service six times, only two of the forced outages kept the unit from available status for as long as 24 hours. Quickly corrected problems with the turbine drive for boiler feedwater pump caused two of the forced outages. Two other times the unit was forced from service but returned in less than 12 hours. In August an operator error tripped the unit; when the unit tripped several superheater welds failed, their repair kept the unit from service for two-days. In March the unit was forced from service by leaks in the superheater area and by oil leaks at several turbine bearings. Repairs were completed and the unit returned to service three days later. Three times during the fiscal year the unit's output was reduced by a forced de-rating. The capacity limitations imposed during the three periods totaled less than two equivalent outage days. The unit's output was limited to 300 MW while boiler water chemistry was adjusted. The unit's output was limited on two occasions while its air heaters were cleaned.

Unit 2 is scheduled to begin an extended scope environmental outage in November 2009. The timing of the outage is in compliance with the Authority's Consent Decree with the EPA. In addition to the routine cleanings, inspections, and replacements that comprise an environmental outage the Authority will also replace the LP turbine. In May 2005 the unit returned to service on completion of a major overhaul. It is scheduled for another major overhaul in fiscal year 2012. The scope will include the replacement of the HP/IP turbines, the reconditioning of the turbine control valves, the inspection of the generator stator and the replacement of the generator rotor with a rotor being manufactured in Switzerland. Boiler sections will be replaced, the main steam and hot reheat lines will undergo non

destructive examination and repairs will be made as necessary, electrical equipment, transformers, relays, switchgear will be inspected, repaired and reset. The scope of the overhaul will be further defined during fiscal year 2010.

Costa Sur Steam Plant

CSSP Unit No. 1 and CSSP Unit No. 2 (both nominally 50 MW) these two units, which entered service in the 1950s, were taken out of service in fiscal year 2004, more than four years ago. During fiscal year 2008 the Authority's stopped reporting on the availability of these two units. During fiscal year 2009 the Authority initiated the process of obtaining the approvals needed to solicit bids for the decommissioning of these units.

CSSP Unit No. 3 (nominal 85 MW) was unavailable for service while undergoing repairs; it was scheduled to return to available status early in fiscal year 2010. During fiscal year 2009 this unit was scheduled from service three times, once for a programmed environmental outage and twice for maintenance outages. Scheduled outages kept the unit from service for 42 days. The unit was forced from service five times, these outages kept it from service for 77 days during the fiscal year. The unit's output was limited for the equivalent of five outage days and it was placed in reserve shutdown four times. Unit 3 generated an average of 64.5 MW, had a gross capacity factor of 41%, and it was in service 4,682 hours during fiscal year 2009.

In August the unit began an environmental outage with an extended scope from which it returned to service 40 days later in early October. During the outage the Authority replaced 200 condenser tubes, installed an upgrade to the burner management system, replaced twelve scanners, burner isolation values, and replaced two low pressure feedwater heaters. Following the outage the unit was scheduled from service for the repair of boiler tube leaks. These repairs were completed and the unit returned to service in less than two days. The other maintenance outage kept the unit from service for less than five hours. The unit was placed in reserve shutdown four times for a total of 52 days during the fiscal year.

While the unit was forced from service five times, only three of the outages were of more than one day's duration. The first was a two-day outage needed to repair boiler tubes; the second forced outage was caused by the failure of generator bushings and current transformers. The unit returned to available status in mid-March, 32 days after being forced out. In mid-May the failure of a generator bushing forced the unit from service for a second time. The unit had not returned to available status at the end of the fiscal year 2009. Concurrent with the repair of the generator and the replacement of current transformers the Authority planned to complete the cleanings, inspections, and replacements that comprise an environmental outage. This would enable them to comply with the Consent Decree requirement without taking the unit from service a second time during fiscal year 2010. The unit's output was limited numerous times during the fiscal year while its condenser was being cleaned. A typical cleaning would limit the unit the equivalent of three operating hours. In January the unit was limited for 33 equivalent outage hours while pump repairs were completed. In March the unit's output was limited for one day while one of its two boiler feedwater pumps was repaired.

Unit 3 returned to available status on completion of its most recent major overhaul in January 2004 and is scheduled to begin its next major overhaul during fiscal year 2012. The capital improvement program includes a multi-year project to refurbish the tank farm dikes and the replacement of fuel oil piping from the tank farm to the station. The installation of an upgrade to the fire detection and suppression systems was in progress. The upgrade included a deluge system for the main power transformers and a CO_2 system for the breaker and switchgear rooms in the station both are scheduled for commissioning during fiscal year 2010. The burner management system upgrade installed in this unit will also be installed in Unit 4 during fiscal year 2010; this work is budgeted in the capital improvement program.

CSSP Unit No. 4 (nominal 85 MW) was on line, capable of full output and capable of regulating frequency. The Authority scheduled the unit from service three times during fiscal year 2009. These scheduled outages, one environmental and two maintenance outages kept the unit from available status for 38 days. Five forced outages kept the unit from service for 29 days while repairs were completed. The unit's output was limited the equivalent of seven operating days and the unit was put into reserve shutdown for a total of 77 days during the fiscal year. Unit 4 generated an average of 64 MW, had a gross capacity factor of 45%, and it was in service 5,229 hours during fiscal year 2009.

Unit 4 began a 33-day environmental outage in late August. During the outage the Authority replaced

several of the unit's low pressure heaters and repaired the excitation system. Later in the fiscal year the unit was scheduled from service for maintenance twice, initially in April for slightly more than one day for the repair of waterwall leaks and in May for almost four days for repairs to the economizer section. The unit was placed in reserve shutdown four times for a total of 77 days during the fiscal year.

Four of the five forced outages that took this unit from service were the result of tube failures in various sections of the boiler. Approximately 12 days were spent completing repairs in the economizer section and 17 days were spent, during two other forced outages, repairing boiler waterwall tube leaks. The cause of the fifth forced outage was quickly repaired allowing the unit to return to service in a few hours. The unit's output was partially down rated several times, together these down ratings equaled eight equivalent operating days. Five of these equivalent days accrued while repairs were being made to one of the unit's boiler feedwater pumps. The remainder accrued while condensers were being cleaned.

Unit 4 is scheduled to begin an environmental outage in November 2009 during which the Authority will install the upgrade to the burner management system. Unit 4 returned to service on completion of a major overhaul in February 2007 and is scheduled to undergo a major overhaul in 2014.

CSSP Unit No. 5 (nominal 410 MW) was online while limited to 390 MW due to high temperature differential at the air preheater. The Authority scheduled this unit from service eight times during the fiscal year. The unit was unavailable for 62 days during the year as it completed two scheduled environmental outages and six maintenance outages. Three forced outages kept the unit from service for an additional nine days. The unit's output was limited a number of times during the fiscal year. These limitations were the equivalent of approximately three outage days. Unit 5 generated an average of 298.7 MW, had a gross capacity factor of 59%, and was in service 7,064 hours during fiscal year 2009.

The unit returned to service at the end of a 39 day environmental outage with an extended scope on the last day of July. In addition to the routine work performed during an environmental outage the Authority also replaced the motors on both boiler feedwater pumps, inspected and repaired turbine control valves, cleaned and repaired air heaters, installed temporary restraints on the main steam line, inspected station transformers, and cleaned the condenser. In May Unit 5 was scheduled out for an environmental outage from which it returned to available status in 19 days. Four of the six maintenance outages, each approximately two days in duration, were scheduled for the repair of tube leaks in waterwalls. During March the Authority scheduled a four day maintenance outage during which the condenser was cleaned, the opacity monitors were replaced, and minor repairs made to the boiler's corners.

During September the failure and repair of tubes in the fuel heater forced the unit from service for six days. The repair of boiler tube leaks were completed during a three day forced outage in January. The unit tripped from service following the loss of power to the burner management system; power was restored and the unit returned to service in less than one day. The partial equivalent day outage limitations at different times during the fiscal year accrued while repairs were completed on a circulating water pump, air heaters, a check valve, and on fans.

The unit returned from a major overhaul in July 2002 and is scheduled to undergo a major overhaul in fiscal year 2011. The major expenditures for equipment are budgeted in the capital improvement program. During the overhaul the Authority will replace feedwater heaters, retube the condenser, replace waterwall panels and boiler corners, replace the HP/IP rotor and refurbish the LP turbine rotor, rewind the generator stator, repair the main steam line, and replace the auxiliary cooling tower. High efficiency seals will be installed in the turbine during the overhaul. Switchgear will be replaced and the unit's main distributed control system (DCS) will be upgraded, a Mark VI control system will be installed and LP heater No. 3 will be retubed.

CSSP Unit No. 6 (nominal 410 MW) was unavailable for service having just begun a major overhaul. The unit was scheduled from service one other time and that was for a Consent Decree mandated environmental outage. Other outages included two forced outages that kept the unit from available status for eight days; the equivalent of five outage days accrued while the unit was limited for a number of different reasons. This unit experienced a number of partial down ratings and several forced down ratings and accrued five and a half equivalent outage days. Unit 6 generated an average of 313 MW, had a gross capacity factor of 68%, and during fiscal year 2009 it was in service 7,816 hours.

During a two-week environmental outage in October the Authority performed NDT of critical lines and equipment in preparation for the start of a major overhaul in June 2009. The Authority also installed temporary restraints on the main steam line control valve chest, which is scheduled for major modification during the unit's overhaul. The unit returned from its most recent major overhaul in June 2000. In mid-June 2009 the unit came out of service at the start of a major overhaul which is scheduled for completion in October 2009. The combined budget allocations for the major overhaul of Costa Sur Unit 6 constitute the largest of the projects funded for Costa Sur in fiscal year 2010. The scope of the overhaul includes asbestos abatement, the replacement of waterwall sections, the installation of new burners, the replacement of several feedwater heaters, the retubing of the condenser, the replacement of the HP/IP and LP turbine rotors, the installation of high efficiency seals in the HP/IP turbine, the rewinding of the generator stator, the modification of the main steam line and the supports thereon. The DCS will be upgraded, switchgear replaced, relief valves tested and recalibrated, the auxiliary cooling tower replaced, turbine control and stop valves cleaned, inspected and repaired as necessary. Mechanical equipment and electrical motors will be inspected; transformers will be inspected and tested. Air heaters will be refurbished with new baskets and seals.

The first of the two forced outages was a two-day outage in November during which the Authority repaired tube leaks in the reheat section and the second, during January 2009, was a six day outage for the repair of tube leaks in the boiler. Problems with the boiler's burners and with low condenser vacuum were the two principal reasons that this unit accrued a total of five equivalent outage days during fiscal year 2009.

Palo Seco Steam Plant

PSSP Unit No. 1 (nominal 85 MW) was on line and capable of full output. During fiscal year 2009 this unit was scheduled from service five times, once for a program outage of 21 days duration and four times for maintenance. Unscheduled forced outages took the unit from service seven times. Forced outages kept the unit from available status for the equivalent of five days. The unit's output was limited for less than the equivalent of one day. The unit was in service for a total of 7,763 hours during the fiscal year; it generated an average of 73.8 MW while in service and had a gross capacity factor of 77% for fiscal year 2009.

From mid-July into early August the Authority scheduled this unit from service to rebalance its turbine rotor and to perform other incidental repair and replacement work. Unit 1 was also scheduled from service twice during August for maintenance. These outages combined to keep the unit from available status for five days, initially for valve repairs and then for the repair of boiler tubes. In September the unit was scheduled out for approximately two days for turbine rebalancing and additional boiler repairs. In March the repair of hydrogen leaks in the generator cooling system were completed during an eight day maintenance outage.

During the second half of the fiscal year the unit was forced from service three times by condenser tube leaks. The unit lost a total of approximately three days while the Authority identified the leaking tubes and plugged them. The boiler tripped due to low water level twice and returned to service in a few hours each time. The unit was forced from service in February when the loss of a circulating water pump caused degradation of the condenser vacuum; the pump was repaired and the unit returned to available status in less than a day. The fifth forced outage caused the unit to be out of service for only a few hours. The 16 equivalent outage hours that this unit recorded were accrued while the unit was turned down for condenser repairs and cleanings.

The following describes modifications to facility systems, and capital improvements that were not unit specific: the four Palo Seco units have been connected to the 115 kV GIS substation, the installation of the FM 200 fire suppression system was completed and the Authority implemented a program of thermographic inspection of switchgear and other major electrical equipment. The installation of a foam system to extinguish fires in the tank farm area and the construction of a deluge system to protect the main power transformers was continuing at the end of the fiscal year. During fiscal year 2010 the power supply to the station's fire pumps will be revamped so that energy needed to power the fire suppression equipment is provided from a source other than a unit within Palo Seco Station. During fiscal year 2009 Fire Department Inspectors inspected the station, equipment, and reviewed training records of station personnel. Unit 1 returned to available status in April 2008 on completion of a major rebuild following a December 2006 fire event. It will undergo an environmental outage during fiscal year 2010.

PSSP Unit No. 2 (nominal 85 MW) was online and capable of full output at the end of the fiscal year. Unit 2 was scheduled from service three times, twice for programmed outages and once for maintenance. This unit was unavailable for service a total of 38 days while scheduled work was completed. The unit was forced from service four times and returned to available status in a matter of hours after each incident. There were four events that led to an accrual of 67 equivalent outage hours during the fiscal year. The unit was in service for a total of 7,849 hours during the fiscal year; the most of any of the station's units. It generated an average of 73.4 MW while in service and had a gross capacity factor of 77% for fiscal year 2009.

The unit returned to available status on completion of a 31 day environmental outage in December. In addition to the routine cleanings, inspections, replacements, and adjustments that are completed during an environmental outage the unit was connected to the 115 kV GIS substation that was completed early in the fiscal year. During May the repair of hydrogen leaks in the generator cooling system accounted for the balance of the fiscal year's scheduled outage hours.

Each of the four forced outages reported during the fiscal year was caused by a failure in a different part of the unit. The repair of a leaking condenser tube forced the unit from service for 12 hours, the longest period that this unit was unavailable due to a forced outage during the fiscal year. Equivalent outage hours totaling approximately three days accrued while the Authority cleaned the unit's condenser. Following heavy rain storms, mud precipitates from the water passing through the condenser, coating tubes and causing condenser vacuum to degrade. On several occasions the unit was limited while the Authority found and plugged leaking condenser tubes.

Unit 2 is scheduled to begin a major overhaul late in fiscal year 2010. During the overhaul the Authority will replace boiler sections, replace the HP/IP turbine rotor, replace the existing seals in the HP/IP sections with high efficiency seals that will increase the turbines efficiency, the LP turbine will be reconditioned, and the condenser will be retubed. The generator's rotor will be rewound. This work will keep the unit from available status for approximately four months. In 2002 this unit returned to available status on completion of its previous major overhaul.

PSSP Unit No. 3 (nominal 216 MW) was forced from service by a fire on December 30 2006; its repair was continuing at the end of fiscal year 2009. Unit 3 had been scheduled to begin a major overhaul in February 2007. After evaluating the extent of the damage sustained by each of the of the Palo Seco units during the fires the Authority determined that this unit would be the last of the four units to return to service. The work originally planned for completion during the overhaul was incorporated into the repair schedule. At the start of fiscal year 2009 the restoration of this unit was 60% complete; it was scheduled to return to service early in calendar year 2009. The completion of work in the turbine generator area was on the critical path setting the unit's return to service. At the start of the fiscal year the HP/IP turbine rotor and the generator rotor were in mainland shops being refurbished; the replacement LP turbine rotor was in protected storage at the station; and boiler work was continuing. In addition work was continuing on control valves, instrumentation and control wiring, and on the distributed control system and the burner management system. The completion date slipped due to the late return of turbine generator components to Puerto Rico and subsequently the correction of turbine seal problems. In mid-March the Authority accepted the unit and continued instrument calibration, the chemical cleaning of the boiler, the completion of work on the polishing system, and the commissioning of switchgear. During the last month of the fiscal year the Authority continued to correct turbine vibration problems and to repair leaks in the generators hydrogen cooling system. On completion of these repairs this unit was expected to return to available status early in fiscal year 2010. The Authority has scheduled Unit 3 for a major overhaul in fiscal year 2016.

PSSP Unit No. 4 (nominal 216 MW) was in service with its output limited to 120 MW due to problems regulating the pressure in the boiler. This unit returned to available status during the second week of January on completion of repairs following the December 2006 station fires. Concurrent with the replacements and repairs made necessary by the fire the Authority also overhauled critical equipment and installed system upgrades. Following its initial return to available status in January, the unit was available for service only 64 days through the end of fiscal year 2009. All but three of the outage days that followed the return to service in January accrued as the result of forced outages. The unit was in service for a total of 1,533 hours during the fiscal year; it generated an average of 162.5 MW while

in service and had a gross capacity factor of 13% for fiscal year 2009.

During this unit's restoration its boiler waterwall sections, the boiler bottom, and burners were replaced, switchgear and load centers were replaced, the HP and IP turbine rotors were refurbished in a mainland shop, the LP turbine rotors were refurbished at the station. High efficiency seals were installed in the turbine. The generator was inspected, its rotor was sent to a shop to be rewedged. A new burner management system and new control systems for the boiler and the turbine generator were installed. Cable tray and control wiring was replaced, critical steam lines were inspected and repaired as necessary. Motors, fans, transformers, condenser valves, and pumps were cleaned, inspected, and maintained prior to the unit returning to available status in January. In May the unit was scheduled from service for the repair of boiler tube leaks. That maintenance outage was the only scheduled outage for the unit during fiscal year 2009; the repairs were completed in less than three days.

One day after its January return to service the unit was forced out for 27 days while its lube oil system was repaired and work was completed on its polishers. The day after returning from that outage it was forced out by leaks in the hot reheat section of the boiler. Following a second forced outage caused by tube failures in the hot reheat section the Authority replaced 256 dissimilar metal welds in that section. Concurrent with those replacements the Authority relined and refurbished the lube oil tank to prevent contamination of the unit's lubricating oil. The unit returned to service at the end of March and continued in service until experiencing three brief, partial day forced outages in mid-April. After several trips caused by high turbine vibration the Authority replaced the thrust bearing and returned the unit to available status within eight days. During May the unit was forced from service six times, only one of these outages lasted more than one day; during that outage boiler tubes were repaired. In June the unit was forced from service twice but returned to available status within hours each time.

Unit 4 is scheduled for an environmental outage in January 2010.

San Juan Steam Plant

Units 1, 2, 3, & 4 have been retired from service for more than three decades.

SJSP Unit 5 (nominal 232 MW) is a combined cycle unit comprised of a combustion turbine with a design capacity of 165 MW and a steam turbine with a design capacity of 67 MW. This unit was connected to the System on October 20, 2008. The Authority accepted the unit on October 22, 2009. Following acceptance the unit was available for service 1,924 hours and in service 1,294 during fiscal year 2009. When in service its combustion turbine generated an average of 142.6 MW. For fiscal year 2009 the combustion turbine achieved a gross capacity factor of 17.1%. Similar performance data were recorded for the unit's steam turbine, 1,793 available hours, 1,148 service hours, an average generation of 46.6 MW and a gross capacity factor of 13.0%.

Unit 5 was in service 544 hours during November, the first full month following its acceptance; this total represents almost half of the service hours this unit would accrue during fiscal year 2009. Over the balance of the fiscal year the unit was scheduled from service for maintenance five times and forced from service seven times. The seventh forced outage occurred in mid-March when a blade in the LP section of the steam turbine failed causing damage to condenser tubes. The unit was designed without a steam bypass system that would allow the operation of the combustion turbine when the steam turbine was unavailable for service. The loss of the steam turbine effectively also forced the combustion turbine from service. At the end of fiscal year the Authority had repaired the steam turbine condenser and had scheduled the completion of steam turbine repairs for mid-September. It was evaluating steam turbine modifications that would enable the combustion turbine to be placed in service before steam turbine repairs were completed.

The Authority has a long term multi-year service agreement with the combustion turbine vendor, Mitsubishi, to perform the inspections of the combustion turbine generators and the steam turbine generators that comprise San Juan Units 5 & 6. The Authority is responsible for the inspection and maintenance of auxiliary equipment in these units. A discussion of the frequency of the contracted inspections and their scope is found in the *Maintenance* section above.

SJSP Unit 6 (nominal 232 MW) is a combined cycle unit comprised of a combustion turbine with a design capacity of 165 MW and a steam turbine with a design capacity of 67 MW. On June 30, 2009 the unit was in service, regulating frequency, and capable of generating 225 MW. This unit was connected

to the System on October 20, 2008. The Authority accepted the unit on October 22, 2009. Following acceptance the unit was available for service 3,759 hours and in service 3,674 during fiscal year 2009. When in service its combustion turbine generated an average of 145.2 MW. For fiscal year 2009 the combustion turbine achieved a gross capacity factor of 54.0%. Similar performance data were recorded for the unit's steam turbine, 3,350 available hours, 3,260 service hours, an average generation of 49.1 MW and a gross capacity factor of 42.4%.

During fiscal year 2009 Unit 6 was scheduled from service five times, once for a modified combustion inspection and four times for maintenance. These scheduled outages kept the unit from available status for 56 days. The unit's initial combustion inspection was completed in 39 days, following the return to service it was scheduled from service twice for the replacement of compressor section filters. The unit was scheduled out for four days in February for maintenance during which miscellaneous repairs and adjustments were made in preparation for a performance test. The Authority replaced instrumentation during a one-day maintenance outage in May. The unit was unavailable for service a total of 29 days as a result of the more than 15 forced outage events that the unit experienced during eight months of the fiscal year that followed its acceptance by the Authority. The unit's output was limited an additional 18 equivalent days by miscellaneous problems with the steam turbine that made it unavailable for service. Many of the outages occurred during the months immediately following its commercial operation. Seventy percent of the service hours that this unit accrued during the fiscal year occurred during the last four months of the fiscal year.

SJSP Unit 7 (nominal 100 MW) was online capable of full output and capable of regulating frequency from 70 MW to 90 MW. The Authority was overhauling this unit at the start of the fiscal year. Following its return to available status in early August it was scheduled from service six additional times for maintenance, these outages kept the unit from available status for a total of 15 days. Forced outages, 14 in all, kept Unit 7 from available status for 43 days during the fiscal year. Equipment failure limited the unit's output for less than two equivalent outage days. During the 6,536 hours that Unit 7 was in service it generated an average of 82.3 MW and had a gross capacity factor of 61%.

This unit began a major overhaul in December of fiscal year 2008 and returned to available status in August. During the overhaul the condenser was cleaned and inspected; defective tubes were replaced or plugged. Waterwall sections on three sides of the boiler were replaced; sections of the FD air duct were replaced. The HP/IP turbines were refurbished in a mainland shop. The generator was opened, cleaned, and inspected. Both boiler feed water pumps were replaced and a new superheater section was installed. Welds on the main steam, hot and cold reheat lines and on the deaerator underwent non-destructive testing and repair as necessary. Electrical switch gear breakers were replaced. The boiler control system was upgraded. Both air preheaters were replaced. The overhaul was scheduled for completion in five months, however, delays in the completion of the refurbishment of the HP/IP turbine rotor, air preheater rotor alignment issues, and the reassignment of personnel to outages on larger units combined to add several months to the overhaul's schedule. Following its return to service it was scheduled out for two days for the removal of the strainers installed during the overhaul to protect the lead and intercept valves. In December it was scheduled out for nine days for the repair of a valve in service to a high pressure heater. During a scheduled maintenance outage in January the Authority repaired an oil leak at a servo-actuator. During a three day maintenance outage in February the Authority replaced condenser strainer components. It was scheduled from service in April for a condenser cleaning and during May for two days while waterwall leaks were repaired.

Two forced outages accounted for 40 of the 43 days that this unit was unavailable after being forced from service. The first of these was a 26 day outage in August that occurred as the unit was being returned to service following its overhaul. During the outage the Authority repaired the normal station service transformer (NSST) buss and repaired generator seal leaks. At the end of October the unit was forced from service following the failure of a circulating water pump; the pump was replaced allowing the unit to return to available status in mid-November. The electrical or mechanical failures that caused the dozen other forced outages were fixed quickly enabling the unit to return to available status each time in less than eight hours. The repair of a boiler feed water pump limited the units output for slightly more than one equivalent outage day.

The capital projects budgeted for San Juan Station will focus on the refurbishment and replacement equipment and on the upgrades of systems that will be installed during the overhaul of the other San Juan units. The Authority has awarded a contract for the design and installation of an upgrade to the station's fire suppression system that will provide protection for transformers and turbine generators, completion is scheduled during fiscal year 2010. The Authority began construction of a 115 kV gas-insulated switchgear (GIS) substation in fiscal year 2009. The GIS substation will be part of the 115 kV underground loop in the San Juan area; completion of the substation is scheduled for fiscal year 2011. The Authority installed a line to carry wastewater from the station to a water treatment plant. Unit 7 is scheduled for an environmental outage during fiscal year 2010.

SJSP Unit 8 (nominal 100 MW) was online and capable of full output. Seven scheduled outages kept this unit from available status for 38 days during the fiscal year. Six of the outages were for maintenance and the other was an environmental outage required by the Consent Decree with the EPA. Ten forced outages kept Unit 8 from service for a total of almost five days. The unit was put into reserve shutdown for approximately seven days. During the 7,583 hours that Unit 8 was in service it generated an average of 86.4 MW and had a gross capacity factor of 75%, the highest capacity factor achieved by the San Juan units and the second highest of the Authority's steam-electric generating units.

During a 30 day environmental outage the Authority also repaired the generator's hydrogen cooler, repaired air in leakage at the condenser, repaired flue gas duct leaks and completed non-destructive examination of the deaerator and main steam and hot reheat lines in preparation for the unit's major overhaul in fiscal year 2010. The unit returned to available status in late September. During a two day maintenance outage in November the Authority cleaned the condenser and made a number of other minor repairs. In March a servo-valve was replaced during a three day maintenance outage. During April the Authority cleaned the unit's condenser and repaired tube leaks and returned the unit to available status in less than two days. The unit was scheduled from service for two days in June while the Authority replaced nine of the boiler's burners.

The need to repair condenser seals and to plug leaking condenser tubes accounted for two of the ten forced outages slightly more than two of the forced outage days. The balance of the forced outages was very brief and the Authority returned the unit to available status in a matter of hours. Two of the forced outages were caused by electrical problems at the NSST. The causes of the other forced outages were each unique and following their repair or adjustment did not recur during the fiscal year.

Unit 8 returned to available status on completion of a major overhaul in September 2002. It is scheduled to begin a major overhaul during fiscal year 2010. During the overhaul the Authority will refurbish all turbine sections, clean and repair turbine control valves, and inspect the generator, rewind the generator rotor. They will replace sections of the exhaust gas duct, rebuild the air preheaters, replace the primary and secondary superheat and reheat sections. The condenser will be retubed and boiler waterwall sections will be replaced. Auxiliary equipment, transformers, motors, and switchgear will be inspected and replaced or repaired as necessary. The overhaul is scheduled over a five month period.

SJSP Unit No. 9 (nominal 100 MW) was online capable of full output and of regulating frequency from 70 MW to 90 MW. In addition to the ten days that the Authority put this unit into reserve shutdown it was also unavailable for service an additional 39 days while undergoing scheduled inspections and repairs. One of the scheduled outages was an environmental outage; the other six were maintenance activities. In addition the unit was forced from service five times; the forced outages kept it from available status an additional three days. The unit was in service 7,520 hours during fiscal year 2009; its average generation of 85.3 MW produced a gross capacity factor of 73%.

The Consent Decree mandated environmental outage was completed in 26 days; during the outage the Authority also repaired the unit's two air preheaters, repaired a boiler feedwater pump, repaired leaks in the generator's cooling system, and cleaned the unit's condenser. The unit returned to available status in mid-April. In early July the Authority repaired a boiler feedwater pump during a six day maintenance outage. In August repairs to tubes in the superheater and waterwalls were completed during a two day scheduled outage. The unit was scheduled out for several more days in October while the Authority cleaned the condenser and completed other repairs. Repairs made during the three other maintenance outages were completed on waterwall tubes, a turbine inlet valve, and on a deaerator steam line.

Approximately half of the forced outage hours this unit accrued during the fiscal year followed a failure in the secondary superheater that was repaired in less than two days. Three of the other forced outages were caused by a faulty low boiler level alarm and the last of the forced outages was a turbine protection trip during March from which the unit returned to available status in a fraction of a day. This unit was placed in reserve shutdown at the beginning of January for ten days. There were no equivalent outage hours accrued by this unit during fiscal year 2009.

In August 2003 this unit returned to service on completion of its last major overhaul. Its next programmed overhaul is scheduled to begin during the first half of fiscal year 2011. During fiscal year 2010 procurements budgeted in the capital improvement fund will be made in preparation for the unit's overhaul. During the overhaul the generator's stator will be rewound, the HP/IP and LP turbine sections will be refurbished. A superheater section and waterwall sections and a low pressure feedwater heater will be replaced. Transformers and electrical equipment will be inspected and repaired as necessary.

SJSP Unit No. 10 (nominal 100 MW) began a major overhaul in early February, it is scheduled to return to available status in August. Before beginning the overhaul the Authority had scheduled the unit from service four times. Eight outage days accrued during these four maintenance outages. The unit was forced from service seven times and accrued a total of 66 forced outage days while the Authority completed repairs following the outages. The unit accrued 750 equivalent outage hours during the fiscal year and was placed in reserve shutdown for a total of 70 days. The unit was in service 1,874 hours during fiscal year 2009; its average generation of 85.8MW produced a gross capacity factor of 18%.

The scope of the overhaul includes retubing the condenser, refurbishing all turbine sections and the installation of high efficiency seals and a vortex system in the turbine, control valves will be cleaned and adjusted, the generator will be cleaned and inspected. Waterwall sections, the superheat and reheat sections are being replaced. New burners are being installed and air preheater baskets replaced. Both boiler feedwater pumps are being replaced and a new condensate tank installed. The Authority will clean, inspect, and repair auxiliary equipment, transformers, motors and switchgear. Cable tray is being replaced. The schedule has been extended in part due to the reassignment of San Juan maintenance personnel to outages on larger units elsewhere in the System. During July the Authority scheduled the unit from service for the first of the four maintenance outages, it returned to available status on completion of repairs to the secondary superheat section. Two maintenance outages were dedicated to condenser cleaning and repairs. These outages accounted for six of the eight days that the unit was unavailable while maintenance was performed.

The longest forced outage kept the unit from available status for 36 days for repairs following an LP turbine blade failure. The unit was forced from service for 24 days while condenser tubes were plugged and other repairs were completed. Earlier in the fiscal year the unit was forced from service for two days while repairs to the unit's excitor and condenser were completed. Condenser section failures forced the unit from service three additional times during fiscal year 2009. The unit was limited for the equivalent of 31 outage days while the Authority completed condenser repairs and cleanings with the unit in service. The Authority placed Unit 10 in reserve shutdown twice during the fiscal year for a total of 70 days.

Unit 10 had been in service almost eight years before the start of the major overhaul in progress at the end of the fiscal year. The budgeted capital projects for this unit are described in the scope of the major overhaul described above.

Combined-Cycle Plant

Total Generating Capacity 1,056 MW

The combined-cycle units installed at San Juan Units 5 & 6 added 464 MW capacity to the System. The status of these units is discussed with the other San Juan units above.

Aguirre Combined-Cycle Plant

The combined-cycle plant is comprised of two units. Each unit consists of four combustion-turbines (CTs), each rated at 50 MW, with individual heat recovery steam generators (HRSGs), i.e., boilers, powering a single 96 MW steam turbine-generator (ST). This configuration yields a unit capacity of 296 MW and a total plant capacity of 592 MW. These units are primarily used as cycling units. For fiscal year 2009 the Aguirre Combined Cycle plant recorded a net capacity factor of 8.7% while generating 2.1% of the System's net generation. The station's net generation for fiscal year 2009 was only 26.4% of its net generation during fiscal year 2008.

In the following discussion the CTs and steam turbine-generators at this plant are identified by Unit and number and with respect to CTs by order within the unit, i.e. the second CT in Unit No. 1 is numbered CT 1-2 and the steam turbine-generator in Unit 2 is identified as ST-2.

At the end of the fiscal year, both of the station's steam turbine-generators and six of the eight CTs were available for service. During fiscal year 2009 the Authority completed a major overhaul of ST-2. Its previous overhaul was completed in February 2001. The Authority has scheduled the overhaul of ST-1 during fiscal year 2011. During fiscal year 2009 there were two significant conditions—leaking exhaust dampers and high cooling water temperatures—that limited the capacity of both steam turbine-generators.

A large part of the limitation was attributed to the inability of the CTs, when operated in combined cycle service, to supply steam at the steam turbine-generator's design conditions. The hot exhaust gases leaving the turbine pass through an exhaust duct in which there is a diverter or damper. This damper, much like a gate, directs the hot exhaust gases to atmosphere if the unit is being operated in simple cycle mode. When operating in combined cycle mode the damper is repositioned to divert the CT's hot exhaust gases to the HRSG where the steam is generated that drives the unit's steam turbine-generator. The original dampers, when positioned for combined cycle service, did not seal well enough to prevent the leakage of some of the hot gases to atmosphere. These exhaust gas losses limited the HRSG's ability to generate steam at design pressure for delivery to the steam turbine-generator causing the steam turbine's generation to be less than design. As part of the capital improvement program the Authority is replacing the dampers in the eight CTs. The replacement diverters are of a different design and have been installed in five of the CTs that are available for service. They have demonstrated better sealing ability and have improved the steam generating capacity of the HRSGs. At the end of fiscal year 2009 replacement diverters were being installed in CT 1-1 and CT 2-4 both of which are scheduled to return to available status in fiscal year 2010. When CT 1-1 and 2-4 return to available status all eight of the CTs will have the capability of being fired by either distillate or natural gas. The Authority has scheduled the installation of a replacement diverter in CT 2-2 in fiscal year 2010; CT 2-2 is the last of the eight CTs to have the replacement diverter installed and marks the completion of a replacement program that began in fiscal year 2004.

In addition to the losses attributed to poorly sealing diverters, the two steam turbine- generators are also limited by inefficient condensing operations. The high temperature of the cooling water in the closed loop cooling system is a major factor limiting the efficiency of the condensers.

At the end of fiscal year 2009 the Authority had completed the upgrade of the combustion system on all eight of the station's CTs. The upgrade brings the CTs to a modified Frame 7EA design, which gives the CT the capability of operating at a higher combustion temperature, thereby improving its efficiency. Additionally the fired hours between combustion inspections, formerly required every 4,000 equivalent fired hours (EFH), is increased 32.5% to every 5,300 EFH. This increase in EFH is likely to increase the interval between combustion inspections by six or more months. The replacement of the air inlet filter houses and filter media is being performed concurrent with the CT's upgrade. The 7EA upgrade, the replacement of inlet air filter houses, the replacement of HRSG soot blowers, the replacement of diverters, and auxiliary equipment were budgeted in the capital improvement program. An upgrade of the DCS has been completed in both units. Other capital projects include the purchase of condenser tubes for installation during the overhaul of ST-1 in fiscal year 2011, the continuation of the multi-year soot blower replacement project, the replacement of motor operated valves, and the purchase of components for the overhaul of ST-1, the replacement of an overhead crane, and scheduled combustion turbine inspections.

ACCP Unit No. 1 was available for service and capable of generating 202 MW. One of this unit's four combustion turbines, CT 1-1, was unavailable for service. While the CT was undergoing a major inspection no steam was being produced in its HRSG. The loss of that steam, coupled with poor condenser vacuum and cooling tower limitations, lowered the steam turbine generator's capacity to 52 MW.

CT 1-1 was unavailable for service while undergoing a major inspection which was in its eighth month at the end of the fiscal year. The inspection began in November; this CT is scheduled to return to available status during the first quarter of fiscal year 2010. During the inspection its generator rotor was rewound, its exhaust diverter was replaced, a new filter house installed, exhaust ducting repaired and

dual fuel capability installed. The Authority scheduled CT 1-1 from service seven times for maintenance for a total of 51 hours during the fiscal year. The longest of the maintenance outages was 15 hours the amount of time the Authority needed to repair an exhaust gas leak. Another exhaust gas leak was repaired during an 8-hour maintenance outage in October. The compressor section was washed during several brief maintenance outages. This CT was forced from service on July 14 by a ground fault in its generator rotor. The rotor was replaced and the CT returned to available status 44 days later. CT 1-1 was forced from service five additional times for a total of less than 22 forced outage hours. Twice the CT was forced out by electrical problems with the generator leading to the replacement of the terminal block and a relay. During fiscal year 2009 CT 1-1 was in service 876 hours or 43.3% of the 2,022 hours it was available.

CT 1-2 was available for service and capable of generating 50 MW. It began a major inspection in mid-January following the failure of a stationary blade in the 2nd row of the compressor section. The turbine rotor and generator rotor were refurbished in mainland shops. The refurbishment of the turbine rotor was completed early in fiscal year 2009 and the rotor was installed in CT 1-4 which had experienced a similar compressor section blade failure late in fiscal year 2008. The refurbished rotor from CT 1-4 was subsequently installed in CT 1-2. By switching rotors CT 1-4 was able to return to available status sooner than otherwise would have been possible and the switch did not delay the return of CT 1-2 to available status. A new exhaust diverter and filter house were installed; the exhaust plenum was modified during the inspection. The package giving the CT the capability of burning natural gas was installed prior to the CT's return to available status in March 2009. The start of the major inspection was delayed for two months and accounts in part for the extended period that this CT was unavailable for service. A week after its return the Authority inspected the fuel bypass valve during a nine-hour maintenance outage. The CT was forced from service three times for a total of 58 forced outage hours. Continuing problems with the fuel bypass valve, ultimately leading to its replacement, were the cause of two of these forced outages and accounted for 49 of the forced outage hours. During fiscal year 2009 the unit was in service 66 hours, or 3% of the hours that it was available for service.

CT 1-3 was available for service and capable of generating 50 MW. CT 1-3 was scheduled from service for a 10-day combustion inspection in December. On eight occasions the Authority scheduled this CT from service for maintenance; these outages kept it from available status for fewer than three days. Two maintenance outages were scheduled for the repair of oil leaks in the accessory box. The repairs were quickly completed and the CT returned to available status in less than one day. The CT was forced from service four times, the longest of which was the result of a System event, following the replacement of a damaged control card the CT returned to available status in less than ten hours. During fiscal year 2009 the unit was in service 2,638 hours, or 31.2% of the hours that it was available for service.

CT 1-4 was available for service and capable of generating 50 MW. This CT was forced from service in June 2008 by the failure of a stationary blade in its compressor section. Four months prior to the blade failure the CT had undergone an inspection of its hot gas path during which blades were inspected and some replaced. The blade that failed in June had been in service fewer than 25,000 hours. The compressor section rotor was shipped to a mainland shop for repair; compressor section blades of a different manufacturer with a different coating were installed. While the mainland repairs were in progress the Authority installed the refurbished compressor rotor from CT 1-2 in CT 1-4. Following reassembly, CT 1-4 returned to available status at the end of October. The CT was forced from service for six days during April by a failure at the feed to the CT's normal transformer. Maintenance outages were scheduled four times during the fiscal year none of the four kept the CT from available status for as much as ten hours and no two of the scheduled maintenance outages were for the inspection or repair of the same equipment. During fiscal year 2009 CT 1-4 was in service 383 hours or 6.7% of the 5,659 hours it was available.

ST-1 was available for service and in economy shutdown on June 30, 2009. Its output was limited to 52 MW, due to the conditions noted above. It is scheduled for a major inspection during fiscal year 2011. During fiscal year 2009 the Authority scheduled ST-1 from service for maintenance in early February following a failure in the unit's condenser cooling water piping. The repair of the cooling water line was completed in early April and ST-1 returned to available status. Earlier in the fiscal year the steam turbine generator had been scheduled from service for

maintenance three other times for a total of almost five days. Repairs to the unit's main power transformer (MPT) accounted for four of the maintenance outage days. There were two forced outages during the fiscal year, in October a failure in the cooling tower's motor control center, MCC, transformer forced the unit out for one day and while repairs to that transformer were being completed the steam turbine generator accrued almost all of the nine equivalent outage days that it accrued during the fiscal year. In fiscal year 2009 the unit was in service 2,509 hours, or 42% of its available hours.

ACCP Unit No. 2 was available for service and capable of generating 210 MW. Three of the unit's four CTs, each capable of generating 50 MW, were available at the end of the fiscal year. The unit's steam turbine-generator was available for service and capable of generating 60 MW. Its output was limited as the Authority was performing a major inspection of one of the unit's four CTs.

CT 2-1 was available for service and capable of generating at design capacity. During November the Authority completed a combustion inspection of CT 2-1 and returned it to available status in nine days. The combustion inspection was the first for programmed inspection of this CT following its return to available status on completion of a major inspection in March 2007, twenty months previously. The CT was scheduled from service for maintenance five times, these scheduled outages kept the CT from available status for a total of almost seven-days. In January the CT was scheduled from service for preventative maintenance of the MPT for CT 2-1 & 2-2. During May the Authority scheduled the CT from service for two days while they repaired a control module. The three other maintenance outages were each less than 12 hours in duration and were scheduled to address different maintenance issues. The forced outage following a trip to protect the MPT servicing CT 2-3 & CT 2-4 was the only forced outage for this CT during the fiscal year. CT 2-1 was in service 1,625 hours or 19.5% of the hours it was available for service during the fiscal year 2009.

CT 2-2 was available for service and capable of generating at design capacity. CT 2-2 returned to service on completion of the installation of the dual fuel package in May 2008. There were no scheduled inspections for this CT during fiscal year 2009. During the first half of fiscal year 2010 it is scheduled to come out of available status for three months for the installation of a new exhaust diverter, a new air intake filter house, and for the refurbishment of the exhaust gas plenum. CT 2-2 is the last of the eight CTs to have these components installed. During fiscal year 2009 this CT was scheduled from available status for a total of eight days. In January the CT was scheduled from service for three days as preventative maintenance to its MPT was completed. During May the Authority scheduled the CT from service for three days for the repair of a control module. The six other maintenance outages were each less than 12 hours in duration and were scheduled to address different maintenance issues. The CT was forced from service once when a relay protecting the MPT tripped, the relay was reset and the CT returned to available status within two-hours. CT 2-2 was in service 1,087 hours during the fiscal year or 12.7% of the 8,572 hours that it was available during fiscal year 2009.

CT 2-3 was available for service and capable of generating 50 MW. During July it returned to available status on completion of a major inspection during which a new exhaust diverter, a replacement filter house, exhaust duct refurbishments, and an overhaul of the combustion turbine were completed. The refurbishment of the generator's rotor in a mainland shop extended the outage into fiscal year 2009. The Authority also installed the components giving the CT dual fuel firing capability. Following its return it was scheduled out for maintenance ten times; two of these outages kept the CT from available status for more than a day, the inspections and repairs made in each of the other maintenance outages were completed in less than 12 hours enabling the CT to quickly return to available status. In October the unit was unavailable for five days while the Authority replaced a compressor. The repair of a control module kept this CT and the other CTs in Unit 2 from service for two days during May. The CT was forced from service nine-times. In September the breaker protecting the MPT for CT 2-3 & 2-4 failed. The breaker was replaced. After the completion of inspections and tests of the MPT and protective devices, the CT returned to available status. The causes of the remaining forced outages were quickly resolved; none kept the CT from available status for as long as ten hours. CT 2-3 was in service 1,229 hours, which was 15% of its available hours.

CT 2-4 was unavailable for service at the end of fiscal year 2009 while undergoing a major inspection. This CT was scheduled from service for a major inspection during the first week of September. It is scheduled to return to available status early in fiscal year 2010. During fiscal year 2009 this CT did not

accrue any maintenance or forced outage hours. The blades in this CT's compressor section had not failed but were manufactured and coated to the same specification as those that had failed in CT 1-1 and CT 1-4. Rather than risk the failure of a blade with the CT in service the Authority decided to replace the compressor section blades during the major inspection blade. During the outage the Authority overhauled the combustion turbine; the turbine rotor and compressor rotor were sent to mainland shops for refurbishment. After starting the inspection the Authority suspended work on CT 2-4 for three months in order to focus on the completion of major inspections on CT 1-1 and CT 1-4. In April work resumed on CT 2-4 as the Authroity completed the replacement of the exhaust diverter, the filter house, and of repairs to the exhaust gas plenum. The installation of the components providing dual fuel firing capability is scheduled for completion during the first quarter of fiscal year 2010. CT 2-4 was in service 719 hours, which was 47.2% of its available hours during fiscal year 2009.

ST-2 was available for service and capable of generating 60 MW. ST-2 began a major inspection in April 2008 from which it was scheduled to return in late August. During the inspection the generator rotor and the turbine's HP and LP rotor were sent to the mainland for cleaning, inspection and refurbishment. Replacement blades were installed in the HP and LP turbines, journals and bearings were machined and the rotor balanced. New bearings and generator casing seals were manufactured. Condenser tubes were hydroblasted; a vacuum pump was replaced; work on the main cooling tower and other mechanical components was completed. ST-2 returned to available status at the end of October. Three weeks after returning to available status ST-2 was forced from service by a failure in a condenser cooling water piping. Before returning the steam turbine generator to service in late February the Authority replaced 90' of the large diameter concrete protected fiber reinforced pipe. The unit was scheduled from service for four days in May while the Authority replaced a unit control module and completed repairs to electrical equipment in the switchyard. ST-2 was in service 250 hours, which was 7.3% of its available hours during fiscal year 2009.

Combustion-Turbine Power

Total Generating Capacity 846 MW

Cambalache Combustion-Turbine Power Blocks

These units were designed to provide rapid response spinning reserve, which helps to ensure System stability in the event of the unanticipated loss of a large generating unit and thereby improve the reliability of service to the Authority's clients. To provide this reserve the Authority typically dispatches at least one of the units at 60% of capacity. Following the loss of the Palo Seco Steam Plant's generation the Authority typically dispatched two of the Cambalache units in base load and held the third in ready reserve. During fiscal year 2009 all three CTs had high availability factors, however, the high cost of distillate fuel, the additional lower cost steam generating capacity made available with the return to service of the Palo Seco units, and the reduced demand on the System, all combined to limit the service hours for each of the CTs during the past fiscal year. The plant's air permit allows 780 unit starts per year, the equivalent of five starts per unit per week. During fiscal year 2009 there were 301 unit starts.

During fiscal year 2008 the Authority decided to defer the conversion of the Cambalache plant to combined cycle. The Authority withdrew the application for a PSD and other permits that had been submitted to regulatory authorities for the combined cycle conversion. The proposal to upgrade the combustion turbines from model GT11N1 to GT11NM technology will be reevaluated during fiscal year 2010. The upgrade will increase the power output of each CT by approximately 16 MW and will necessitate the reissuance of certain environmental permits.

During fiscal year 2009 Authority personnel completed planned inspections on each of the combustion-turbines. The Authority has entered into a technical services contract with the station's original equipment supplier that remains in effect through 2011. It obligates the supplier to provide a technical advisor on a full-time basis at the station and to provide the replacement parts needed in the hot gas path during class C inspections of the combustion turbine. Refer to the *Maintenance* section for a description of the scope of a class C inspection. The Authority's employees are responsible for the installation of the replacement parts. The service agreement also covers the provision of additional technical assistance as required for scheduled maintenance.

Since initial operation each of the Cambalache units has experienced at least one compressor section blade failure. Blade failure analyses concluded that the corrosive effects of airborne contaminants caused the failures. The Authority has taken steps to reduce the intake of airborne contaminants into the compressor section and they implemented a program of online compressor section washings performed on each shift and off line compressor section washings performed at two-week intervals. Additionally the original equipment manufacturer, OEM, tested a number of different sacrificial coatings to determine which coating would provide up to 100,000 hours of protective service to the blade. Following analysis the OEM, recommended a blade coating which has since been applied to the blades in the first ten rows of the compressor section. The coated replacement blades are installed on a rotor in the OEM's mainland shop and shipped to Puerto Rico for installation during a class C inspection. The last of the three CTs to receive a rotor with coated blades did so during a class C inspection early in fiscal year 2009. All compressor section cleanings are now done with the unit off line.

The station's air permit established the maximum firing rate of distillate fuel oil at 104 gallons per minute (gpm) per unit. Adherence to this fuel oil consumption rate impacts the capacity of these units. The amount of the limitation is subject to ambient air temperature. Higher air temperatures decrease a unit's power output while cooler temperatures, only rarely experienced in Puerto Rico, increase power output.

The work described in this paragraph was budgeted in the CIP and completed during fiscal year 2009. The Authority performed a class C inspection of unit 3 and the installation of a replacement once through steam generators (OTSG) in the CT. The replacement of the OTSGs will improve the CTs response to load changes. During fiscal year 2009 the Authority completed the installation of a new turbine generator control system, P-400, with its installation during Unit 3's class C inspection. The P-400 control system is capable of controlling the demineralized water plant and balance of plant (BOP) systems. During fiscal year 2009 the Authority purchased replacement tube bundles for the station's air fan heat exchangers. The tube bundles will be installed during upcoming scheduled inspections. The upgrade of the fire detection and suppression system in the administration building and control room was in progress at the end of the fiscal year.

Please refer to the *Maintenance* section above for a full description of what constitutes a class "A", "B", and "C" inspection referred to in this section.

CCTP Unit No. 1 was available for service and capable of generating 82.5 MW on June 30, 2009. During fiscal year 2009 the unit was scheduled out of service six times for a total of 16 days; one of these outages was for a class B inspection and the other five were maintenance outages. There were also ten forced outages, which kept the unit from available status for a total of almost four days.

During October the Authority completed a six-day class B inspection of this unit. In December the unit was scheduled from service for eight days while insulators on the line transmitting power from the transformer to the switchyard were replaced. During the other maintenance outages the Authority sealed a gas leak at a turbine flange, washed the compressor section, and scheduled the unit out twice for the repair of a pressure switch on the main power transformer. These last two repairs were completed in less than 12 hours.

On three occasions the unit was forced from service by gas leaks at a turbine flange. Each time the Authority was able to reseal the flange and return the unit to available status in less than one day. Electrical trips accounted for three forced outages during September. The three repairs that followed were completed in a total of less than two days. During June the unit was forced from service by a leak in the lube oil system. The failures that caused the two other forced outages were repaired in less than five hours and the unit returned to available status.

For the second consecutive year Unit 1 had the best heat rate of the three Cambalache units. This CT's next class A inspection is scheduled for December 2009 and its next class C inspection is scheduled during fiscal year 2011. For fiscal year 2009 this CT had an availability factor of 94%. Unit 1 had 105 starts, was in service 2,183 hours, generated an average of 63.7 MW, and had a gross capacity factor of 19% for the fiscal year.

CCTP Unit No. 2 was available for service and capable of full output on June 30, 2009. During fiscal year 2009 the unit was scheduled out of service seven times for a total of nine days: once for a scheduled inspection and six times for maintenance. There were two forced outages, which kept the unit from available status for a total of 37 days.

The scheduled inspection, a class A inspection, was completed in two days during July. Three maintenance outages were scheduled in the first half of the fiscal year, these maintenance outages kept the unit from available status for slightly more than one day. Two of the outages were for the repair of a fuel valve, during the third the Authority repaired a pump. In April the unit was unavailable for service for approximately three days while a fuel oil leak was corrected. The Authority scheduled the CT from available status twice during June, each time the maintenance was completed in less than two days. The Authority performed maintenance on the unit's opacity monitors and completed inspection and repair of the lube oil system during the second of the outages.

This model combustion turbine has five stages in the turbine section. In September a third stage blade failed, damaging the blades and vanes in stages three, four, and five. The damaged sections of the turbine were replaced and the CT returned to available status 37 days after being forced out. The blade that failed had been in service approximately 4,000 hours. The OEM conducted an initial analysis of the failed blade and found no evidence of foreign object damage. The report concluded that the failure was the result of the unit being cycled. The Authority disputed this finding. At the end of the fiscal year the OEM had reimbursed the Authority for part of the cost of the repair. The Authority is pursuing additional payment from the OEM. In January the CT was forced from service for several hours by a fault in the 230 kV line to the switchyard.

Unit 2 is scheduled for a class B inspection early in fiscal year 2010. It returned from a class C inspection in November 2007. For fiscal year 2009 this CT had an availability factor of 88%; it had 92 starts, and was in service for 1,678 hours. It generated an average of 63.5 MW when in service. Unit 2 had a gross capacity factor of 15% for the fiscal year.

CCTP Unit No. 3 was available for service and capable of full output on June 30, 2009. During fiscal year 2009 the unit was scheduled out of service eight times for a total of approximately 49 days: twice for planned outages and six times for maintenance outages. There were six very brief forced outages, which kept the unit from available status for a total of less than 24 hours.

The CT returned to available status on completion of a 43-day programmed class C inspection in mid August. In addition to the normal scope of work in a class C inspection the Authority replaced the OTSG and installed the P-400 control system, the P-400 had previously been installed in the other two units. The air filtering system was replaced with a static filtering system installed in an air intake house designed with rain hoods and a mist eliminator. The compressor was washed with the unit off line during November and returned to available status the same day. Routine maintenance, completed in less than 24 hours was performed during four of the maintenance outages. An inspection of the continuous emission monitoring system, CEMS, was made in June and kept the unit from available status for less than three hours. The only maintenance outage that kept the unit from available status for more than 24 hours involved the repair of the unit's static frequency converter. The unit returned to available status 36 hours following the start of the maintenance outage.

The unit was forced from service six times and accrued a total of 23 forced outage hours as a result of these events. The causes of forced outages, four during June, were each different and each was quickly remedied.

Unit 3 is scheduled for a class A inspection early in August 2009. For all of fiscal year 2009 this CT had an availability factor of 87%; had 104 starts, and was in service for 1,248 hours. It generated an average of 68.4 MW when in service. Unit 3 had a gross capacity factor of 12% for the fiscal year.

Other Combustion-Turbine Power

The Authority has nine Combustion-Turbine Power Blocks, each with two simple cycle machines. In the discussion that follows, combustion turbine and gas turbine as synonymous and they will be identified as GT, in accordance with the Authority's convention. The eighteen gas turbine units are located at seven sites and have an aggregate capacity of 378 MW; the GTs went into service between 1971 and 1973. They are distillate-fired Frame 5 gas turbines, each capable of generating 21 MW. During fiscal year 2009 the Authority also brought eight new combustion turbines into service at Mayagüez. These aero-derivative units provide the Authority 220 MW of capacity at Mayagüez and a System total of 598 MW of simple cycle combustion turbines. For fiscal year 2009 the GTs had a combined equivalent availability of 88%. The net generation of the GTs during fiscal year 2009 was 31% of the prior fiscal year's net generation with the decline due to the return to service of several of the Palo Seco steam electric generating units, the relatively high cost of distillate fuel, and lower system demand. During fiscal year 2009, the

eight combustion turbines at Mayagüez accounted for 26% of the net generation of all GTs. Their generation was almost matched by the six GTs at Palo Seco; combined these two GT sites accounted for more than half of the gas turbine's generation during the fiscal year. Twenty-two of these units were available for service at the end of the fiscal year.

The Authority continues its program of replacing the fire suppression systems at each of its GT sites with CO_2 systems. The CO_2 systems provide fire suppression capability in each of the GT's compartments. At the end of fiscal year 2009 these systems had been installed at Palo Seco, Costa Sur, Aguirre, and Jobos GT sites. The combustion turbines at Mayagüez are protected by a similar system. The Authority will complete the installation CO_2 fire suppression at the three remaining GT sites in fiscal year 2011. Engineers in this division have been trained to perform thermographic inspections of electrical systems and do so at regular intervals.

The eight aero-derivative gas turbines that entered service during fiscal year 2009 are capable of generating 220 MW. These units replace four of the Frame 5 GTs that went into service at Mayagüez in 1972. The new units have a heat rate approximately 30% lower than the average heat rate of the older Frame 5 GTs.

Scheduled inspections were performed on 11 of the Authority's 22 GTs during the fiscal year. The service hours of many of the gas turbines were lower during fiscal year 2009 than during fiscal year 2008. As the GTs accrued fewer service hours the months between scheduled inspections increased. The following paragraphs describe what was completed during several of the more extensive inspections conducted during the fiscal year. Also discussed is the status of gas turbines that were not available for service at the end of the fiscal year.

Yabucoa's GT 1-1 returned to service in August on completion of a major inspection of six months duration. During the inspection the Authority replaced the turbine compressor section and the generator's rotor. A Mark Vl control system and a universal fuel system were installed. The ratchet and torque converter and clutch were replaced as was the exhaust plenum. The air inlet house was refurbished. Compartment doors were replaced and the unit was painted before returning to available status.

Daguao GT 1-1 was unavailable and undergoing an intermediate inspection from November until June. During the inspection the Authority installed a Mark Vl control system and replaced the ratchet, torque converter, and clutch. The site's diesel motor was inspected and routine maintenance completed. The generator was opened, the rotor removed cleaned and inspected. The excitor was inspected and the voltage regulator was replaced. Combustors were inspected; before returning to service the unit was painted.

Jobos GT 1-2 was scheduled to return to service in August on completion of a major inspection that began in late March 2009. Before returning to service the generator rotor will be replaced, the stator cleaned and inspected, and a Mark Vl turbine control system will be installed. The voltage regulator will be replaced as will the ratchet and torque converter. A universal fuel system will be installed and the starter motor will be rebuilt.

With the connection of Palo Seco 3-1 & 3-2 to the 115 kV GIS substation, all three of the Palo Seco GT power blocks were connected to the newly constructed substation.

At the end of fiscal year 2009 two of the Mayagüez units were unavailable as particulate had been found in the lubricating oil. The units came out of service in late June and their return was pending at the end of the fiscal year. Jobos 1-1 was also unavailable after being forced from service in early June. The Authority was replacing switchgear and had scheduled its return to available status during the first week of fiscal year 2010.

Hydro Production Plant

Total Generating Capacity 100 MW

The Authority has 21 hydroelectric generating units at eleven locations. They have an aggregate capacity of 100 MW. The Authority reported that for fiscal year 2009 the hydroelectric generating units had an aggregate equivalent availability of 92%, generated 170,331 MWh or 39% more than they generated during the previous fiscal year and had an annualized service factor of 23%. On June 30, 2009 the hydroelectric system was capable of generating 79 MW. The status of the units that were unavailable or limited on that date is described below. Briefly, at the end of fiscal year 2009 two units, each at a different location were unavailable for service. During fiscal year 2010 the Authority will begin a three year program of upgrading the fire suppression systems at hydroelectric stations. During fiscal year 2010 the Authority is scheduled to award a contract for the installation of fire suppression systems at the Dos Bocas Station. Specifications and bid packages will

be prepared for the supply and installation of fire suppression systems for the Rio Blanco, Toro Negro, Garzas and Yauco hydroelectric units during fiscal years 2011 and 2012. Other multi-year capital projects include the replacement of control systems, breakers, and the replacement of the penstock valve at Garzas. More than 13,000 hours were expended during the fiscal year completing scheduled inspections and maintenance on the 21 units during the fiscal year. A representative description of the repairs and replacements completed following scheduled and unscheduled outages follows:

Yauco 2-1 was in testing on June 30, 2009 following completion of repairs to its commutator. The 4.5 MW unit was forced from service in mid-December; the date for its return to available status was extended several times. Yauco 1 with a design capability of 25 MW is the Authority's largest hydroelectric unit; its output was limited throughout the fiscal year, however, due to damage to its nozzles, other mechanical components, and reduced water flow due to obstructions in its tunnels. The replacement of nozzles and other components will be a part of the unit's overhaul. Before the overhaul can begin the Authority must complete a bypass piping system that would enable water to flow around the station to consumers in the valley below Yauco 1. The Authority plans to complete the installation of the bypass system during fiscal year 2010. On June 30, 2009 Yauco 1 was capable of generating 12 MW.

The 3.6 MW of capacity at Caonillas Unit 2-1 continues to be unavailable due to the sedimentation in Lake Vivi. The unit has not been available since September 1998 when Hurricane Georges struck Puerto Rico.

There are five generators in the two Toro Negro hydroelectric stations; they have a combined capacity of 10.5 MW. Unit 2-1 with a 2 MW capacity was unavailable for service for three months while breakers were changed and the generator repaired.

Garzas Unit 2-1 with 5 MW of capacity was unavailable for service from mid October until mid December while control cables were replaced and for four months starting in February while penstock repairs were completed. Units 1-1 and 1-2 were forced from service for penstock repairs during May 2009.

Dos Bocas Unit 1-3 with 5.0 MW of capacity returned to available status on completion of a two month-long scheduled inspection during which the Authority replaced the unit's excitation system and completed other repairs.

Diesel Generators

The diesel generators installed by the Authority on the islands of Vieques and Culebra provide backup power in the event of interruption of the power delivered by submarine cables to these islands. At the end of the fiscal year the seven diesel generators were available for service. During fiscal year 2009 the four diesel generators on Culebra, with a combined capacity of approximately 2.0 MW, generated 67 MWh. These four diesel generators were in service a total of 319 hours. On Vieques the Authority's two 3 MW diesel generators and single 1 MW diesel generator were in service a total of 121 hours during the fiscal year and generated a total of 120 MWh.

FUELS

Since March 2007 the Authority has been burning a residual fuel oil with a sulfur content not exceeding 0.5% by weight in all of its large steam electric generating stations. In that month the large steam electric generating stations at Aguirre and Costa Sur went from burning a fuel with 0.75% sulfur content to a residual fuel oil not exceeding 0.5% sulfur by weight. Four years earlier in compliance with an agreement with the EPA the Authority began burning this residual fuel oil with low sulfur content at its steam electric generating stations at San Juan and Palo Seco on the north coast of Puerto Rico. Following the switch to the low sulfur fuel, the two stations on the south side of the island discontinued the use of fuel additives. Also all new contracts for the purchase of the distillate fuel oil that is burned in the Authority's simple and combined cycle units will specify that the sulfur content not exceed 0.05% by weight, to realize better pricing and supply options.

The Authority's current practice for fuel procurement has been to solicit bids for the supply of fuel on the basis of a one-year contract with the option of extending the contract for an additional year. Extension of the contract for the option year is discretionary for either party to the contract. If one party elects not to exercise the option year provision that party must notify the other party to the contract four months prior to the end of the first year. This provides either party the time to pursue contracts elsewhere. The Authority's experience is that the parties agree to extend the contract through the option year approximately 80% of the time.

In January 2009 the Authority awarded a contract for the supply of the residual fuel oil for the Aguirre Steam Plant. In February 2009 the Authority took delivery of residual fuel oil per this contract. The

second year, an option year, if exercised would extend this supply contract through January 2011. At the end of the fiscal year the Authority had requested bids for the supply of residual fuel oil for the Costa Sur Steam Plant. The contract was scheduled for award during July 2009. The residual fuel for Palo Seco and San Juan Steam Plants is supplied per a single contract that was awarded in April 2008. This contract was extended through its option year; it will be put out for rebid in March 2010.

The Authority's contract for the supply of distillate fuel oil for the San Juan Units 5 & 6 was awarded in February 2009. This contract, if extended through an option year would terminate in fiscal year 2011. The San Juan units burn a distillate with sulfur content of not more than 0.05% by weight.

The contract for the supply of distillate for the Cambalache units has been extended through the June 2009. The distillate supplied under the expiring contract contained not more than 0.15% sulfur by weight. The supply contract being bid at the end of fiscal year 2009 specified a distillate with a sulfur content not exceeding 0.05% by weight. This contract would also cover the supply of distillate for the units at the Aguirre Combined Cycle Plant.

The contract the Authority awarded in May 2008 for the supply of distillate with sulfur content not to exceed 0.05% has been extended through April 2010. This distillate will be burned in the Authority's eighteen Frame 5 combustion turbines each having a 21 MW capacity and in the four 55 MW aero-derivative simple cycle combustion turbine units which entered service at Mayagüez during fiscal year 2009. The 55 MW aero-derivative units replace four Frame 5 combustion turbines that were taken out of service at the end of fiscal year 2008.

BATTERY ENERGY STORAGE SYSTEM

The 20 MW Battery Energy Storage System, BESS, at Sabana Llana was commissioned in August 2004. The plant consists of two units designated 1A and 1B. More than 3,000 batteries powered each unit. The plant was designed to provide ready reserve capacity in response to a System disturbance and power factor correction when needed. Early in fiscal year 2006 one of the units was forced from service by a fire. Following the fire the Authority determined there were a number of design issues that would prevent the batteries from providing safe and reliable service. The Brazilian manufacturer of the batteries disputes the Authority's position and has been unwilling to replace the batteries. The Authority and the manufacturer have been unable to reach a settlement. The Authority has filed suit; at the end of fiscal year 2009 the case continued in the discovery stage.

SPARE COMPONENTS

To reduce the unscheduled outages of various units, the Authority has purchased a number of critical spare components (see the following list). Using such spare components during an emergency outage can greatly expedite the unit's return to service. Once the damaged component is repaired, it becomes the spare. This practice has significantly reduced the downtime of some of the Authority's large units thereby helping to maintain both unit and System availability. The following is a list of major spare components:

- HP/IP and LP turbine rotors for Aguirre Unit Nos. 1 & 2
- HP/IP and LP turbine rotors for Costa Sur Unit Nos. 5 & 6
- Motors for FD, ID, & GRF for Costa Sur Units Nos. 5 & 6 and Aguirre Unit Nos.1 & 2
- Power transformer adaptable to Costa Sur Units Nos. 5 & 6 and Aguirre Unit Nos.1 & 2
- Emergency station service transformer for Aguirre Steam Station
- Generator rotor for Aguirre Unit Nos. 1 & 2
- LP turbine rotor for Palo Seco Unit Nos. 3 & 4
- Generator rotor for Palo Seco Unit Nos. 1 & 2
- Power transformer for Palo Seco Unit Nos. 3 & 4
- CT generator for the Aguirre Combined-Cycle Plant
- CT turbine rotor for the Aguirre Combined-Cycle Plant
- Power transformer for Aguirre Combined Cycle Station
- Two generator rotors for the 21 gas turbines
- Compressor rotor assembly for a 21 MW gas turbine
- Service transformer for San Juan Station Units
- Replacement motors for all large pumps
- Replacement rotors for FD, ID, & GRF fans
- Large pumps and vacuum equipment for combined cycle & steam-electric units
- Burners, soot blowers, air heater components for steam-electric units

PRODUCTION PLANT CAPITAL EXPENDITURES

Production plant capital expenditures in millions of dollars are forecasted to be $128.0, $104.0, $90.3, $115.0, and $161.5 in fiscal years 2010 through 2014 respectively. Actual production capital expenditures in fiscal year 2009 amounted to $246.6 million as shown in *Appendix VI, Capital Expenditures.* Details by Budget Item Number for fiscal years 2010 through 2014 are shown in *Appendix X, Details of Capital Improvement Program.*

ENVIRONMENTAL

The Environmental Protection and Quality Assurance Division is responsible for assisting the Authority's operating Directorates to comply with all applicable Federal and Commonwealth environmental laws and regulations. The Environmental Protection Division's responsibilities include the development of comprehensive programs to achieve the Authority's environmental performance goals. They have primary responsibility for obtaining the permits required to add Authority owned capacity to the System or to modify existing capacity. These responsibilities include defining the measures necessary to remain in compliance with new regulatory requirements and responding to alleged instances of noncompliance cited by federal or local environmental agencies.

During fiscal year 2009 the Authority performed environmental protection or environmental remediation projects at each of its major generating stations. Environmental projects were budgeted at $11.9 million and actual 2009 expenditures totaled slightly more at $12.2 million. The Authority's five-year Capital Improvement Program (CIP) for fiscal year 2010 through 2014 identifies environmental projects valued at $78.9 million. During fiscal year 2010 these projects are budgeted at $10.3 million.

In February 1992 the EPA conducted a multimedia inspection of the Authority's four steam electric power plants (Aguirre, Costa Sur, Palo Seco, and San Juan) and the Monacillos Transmission Center. In December 1992, the EPA identified several instances of noncompliance related to air emissions, water discharges, and to the Spill Prevention Control and Countermeasure (SPCC) compliance program at the Authority's four major steam electric generating stations and at the Monacillos Transmission Center. These findings led in March 1999 to an agreement between the agencies of the federal government and the Authority, which became the basis for the court approved Consent Decree which is still in effect, although subsequently revised and amended. The Authority agreed that starting in March 2003 the residual fuel oil burned in the steam electric generating stations at Palo Seco and San Juan on the north coast of the island would have a sulfur content not exceeding 0.5% by weight. Since March 2007 the Authority has been burning a fuel oil with a sulfur content not exceeding 0.5% by weight at its south coast steam electric generating stations at Aguirre and Costa Sur. For more discussion on this refer to the *Fuels* section of *System's Operations*. During fiscal year 2007 the Authority completed projects to reduce NOx emissions at steam electric generating stations at Palo Seco, Aguirre, and Costa Sur. As a condition of receiving certain permits the units at San Juan Station had previously been modified to reduce NOx emissions. The Authority and the EPA monitor compliance with the lower NOx emissions requirements.

The Authority has selected environmental consultants to assist them on air emission compliance strategies and projects, as well as compliance issues arising under sections 316 (a) & (b) of the Clean Water Act. The largest of the multi-year environmental projects budgeted in the CIP are related to the Clean Water Act's Section 316 and entail the refurbishment of the cooling water intake system at the Costa Sur steam electric generating station and the rerouting of that station's cooling water, thermal effluent, discharge system. Work associated with these two projects is budgeted through fiscal year 2014 at $8 million and $37.5 million respectively. The Authority prepared a Detailed Engineering and Environmental Review (DEER) of several options for reducing the temperature of Costa Sur's thermal effluent. Following review the EPA approved a plan for an offshore submerged discharge of the station's thermal effluent. Additional impact studies are being prepared for submission to the US Corps of Engineers. Construction of the replacement thermal effluent discharge system at the Costa Sur Steam Plant will continue beyond fiscal year 2014 and is estimated to cost approximately $60 million.

To comply with the Puerto Rico Environmental Quality Board's Underground Injection Control regulations the Authority has completed the closure of septic systems at steam electric generating stations at Aguirre, San Juan, and Palo Seco. Sanitary systems at these stations have been connected to the Puerto Rico Aqueduct and Sewer Authority's treatment systems. During fiscal year 2010 the Authority will

complete the tie-ins to the sanitary sewer systems at the Costa Sur Steam Plant. Costa Sur is the last of the major stations at which septic system tie-ins remain to be completed. Remediation of closed septic systems will continue during fiscal year 2010.

The Authority maintains an asbestos abatement program through which it is reducing exposures to asbestos containing materials through encapsulization and removal.

In 2003 the EPA approved the Authority's plan to achieve compliance with the Spill Prevention Control and Countermeasures (SPCC), provisions of the Oil Pollution Control Act of 1990. Through fiscal year 2012 the Authority has budgeted $8.8 million for the inspection, testing, and repair of fuel oil tanks, the refurbishment of tank dikes and the installation of secondary containment around fuel oil tanks; these projects have been ongoing since 2004 at electric generating stations. This budget allocates funds for contamination control projects at the Authority's hydroelectric and combustion turbine plants and for the replacement of a distillate line to the Palo Seco generating station. More than half of the Authority's substations contain quantities of oil in transformers and other electrical equipment that trigger the inspections and control measures mandated by these standards. The Authority has budgeted $5.1 million through fiscal year 2012 for SPCC compliance projects at substations and transmission centers. The Authority will meet with the EPA during fiscal year 2010 to discuss the schedule for the completion of Facility Response Plans (FRP), and for the inspection and modification of these facilities.

As of March 2009 the Authority reported achieving compliance in excess of 99% with its in-stack opacity requirements and with its Air Quality Compliance Program and also achieving the same high level of compliance with Clean Water Act regulations. At the end of fiscal year 2009 none of the Authority's generating stations was on probation with the EPA.

COGENERATORS

The Authority has entered into long-term Power Purchase Agreements (PPAs) with the owners of two cogeneration plants in Puerto Rico. These plants, one fueled by natural gas (vaporized LNG) and the other by coal, bring fuel diversity to the island's generation mix. The Authority's PPAs with the cogenerators establish the method for calculating the cost of the fuel component of the cogenerators' energy charge for a twelve-month period at the start of each calendar year. The plants incorporate emission control technologies enabling them to comply with stringent environmental standards; both plants are highly efficient. The Authority controls the dispatch of the cogenerators' power. During fiscal year 2009 the cogenerators accounted for 30.6% of the System's net generation. During fiscal year 2008 the cogenerators had generated 31.8% of the System's net generation. (For further discussion of these power producers see the *Capacity Planning* section.)

The Authority is treating its purchased power costs as an operating expense in its various financial schedules and it is recovering them from its clients utilizing a purchased power charge similar to its fuel charge. As previously noted, both of these charges are combined and appear on the client's bill as the adjustment charge. The Authority's purchased power costs, as shown in *Appendix III, Detail of Operating and Maintenance Expenses,* for fiscal year 2009 totaled $671.8 million; in fiscal year 2008 the total was $661.1 million. For fiscal years 2010 through 2014 the Authority projects purchased power costs in millions of dollars to be, $711.7, $716.0, $734.8, $755.9, and $727.6, respectively.

In the following narratives a scheduled outage will be noted regardless of duration and unscheduled outages or limitations of a unit's output of one or more days duration will be noted. Also an event that removed more than one of a plant's units from the system is noted below regardless of duration.

EcoEléctrica, L.P.

On March 21, 2000, the Authority began buying 507 MW of power from EcoEléctrica, L.P. in accordance with a 22-year PPA. The plant consists of two combustion-turbines (CTs) each with a heat recovery steam generator (HRSG), i.e., boiler, combining to power a single steam turbine-generator, STG. Each of the CTs is capable of generating 167 MW; the steam turbine-generator is capable of generating 173 MW. The plant's waste heat is used in a desalinization plant capable of producing 2 million gallons of fresh water a day. The water is for its own use and for sale to the Puerto Rico Aqueduct and Sewer Authority. The EcoEléctrica, L.P. complex also includes an LNG unloading dock, an LNG storage tank, an LNG vaporizer, and associated facilities.

For fiscal year 2009 EcoEléctrica achieved an equivalent availability of 89.6%, significantly below the equivalent availability of 93.9% achieved during fiscal year 2008, but only slightly below the fiscal year 2009 target of 90%. Due to the number and exten-

sive scope of the maintenance inspections scheduled for the EcoElectrica units during fiscal year 2009 the Authority lowered the target equivalent availability from 93% to 90% for the current fiscal year. A provision allowing for this reduction is contained in the PPA. The plant had a capacity factor of 75.9% while generating 9.8% less energy in fiscal year 2009 than in the prior fiscal year. Each of the plant's three units was in service and capable of full output on June 30, 2009. CT 1 was unavailable for service a total of 42 days during the fiscal year, the major inspection of the combustion turbine-generator that began in February accounted for 36 of the 42 days. This CT was forced from service for repairs seven times during the fiscal year. Two of these one-day outages were for the repair of a turbine bearing and the third was for the installation of blinds to isolate the CT from the steam turbine-generator. High turbine vibration in CT 1 forced from it from service for a day and a half during April. In January an operator error led to a boiler feed pump being shutdown, tripping the unit and causing the Authority to shed load. Service was restored to affected clients within 15 minutes.

CT 2 was unavailable for service for 25 days during fiscal year 2009. In January the CT was scheduled from service for a 12-day combustion inspection that was extended an additional ten days for the replacement of blades in the turbine and compressor section. Shortly after returning to available status CT 2 was scheduled from service for maintenance and returned to available status two days later. CT 2 was forced from service twice during the fiscal year and returned to service in less than four hours after each trip. CT 2 was generating 270 MW when the second of these trips occurred forcing the Authority to shed load. The Authority was able to restore service to affected clients within 25 minutes; EcoEléctrica returned the unit to available status in less than two hours.

EcoEléctrica's steam turbine-generator capacity was limited during the 67 days during fiscal year 2009 that one of CTs with which it was combined was unavailable for service. When a CT tripped so too did the STG. Additionally the STG was scheduled from service for 29 days for a major inspection. During the inspection blades in the HP and IP sections of the turbine were replaced. Turbine seals were replaced. The generator was cleaned and inspected, and nozzles were sandblasted. The STG returned to available status in early March. The STG was forced from service three times, once following the failure of a system controlling the handling of LNG, another time during April by the loss of the instrument air system, and the third time by a malfunction in a relay protecting the generator. When this last event occurred the Authority shed load but returned power to all of the affected clients within 18 minutes. The STG returned to available status after each of these trips in less than one day.

The Authority had forecast that EcoEléctrica would generate 14.4% of the System's energy during fiscal year 2009. For fiscal year 2009 EcoEléctrica provided 15.1% of the System's energy. The Authority forecasts that EcoEléctrica, L.P. will generate 15.8% of the energy sold by the Authority during fiscal year 2010.

AES-PR

AES-PR's coal-fired steam-electric cogeneration station began commercial operation in November 2002. The owners of the facility have entered into a PPA with the Authority to provide 454 MW of power for a period of 25 years. The station is comprised of two circulating fluidized bed steam generators employing clean coal burning technology and two steam turbine-generators each capable of generating 227 MW. During fiscal year 2009 AES-PR accounted for 15.7% of the energy sold by the Authority. Although this was more than the 14.6% of the System's net generation that the Authority had forecast that AES-PR would provide, its net generation during fiscal year 2009 was 7.5% less than in fiscal year 2008. For the remaining years of the PPA's term, the plant has a target equivalent availability of 90%, a target it has achieved in prior years. During fiscal year 2009 AES completed major overhauls of both units and achieved an equivalent availability of 88.2%. The plant realized a capacity factor of 82.7%. Three times during the first half of fiscal year 2009 the station's capacity was limited as coal fuel became too wet to maintain the stations capacity. While limitations due to heavy rains lasted six days they accrued less than two equivalent outage days for the station.

Unit 1- at the end of fiscal year 2009 this unit was online and capable of generating 227 MW. During fiscal year 2009 there were two scheduled and three forced outages. These outages kept the unit from available status for a total of 55 days, additionally the unit's capacity was limited on six occasions, however, the limitations were relatively small and brief, totaling less than one equivalent outage day. In November the unit came out of service for 15 days while scheduled maintenance was performed. In late June Unit 1 returned to service on completion of a 25-day major overhaul during which the precipita-

tor's collector plates were replaced, boiler and refractory repairs were completed. In September a component within the UPS failed and the unit tripped while generating 254 MW; the trip caused the Authority to shed load. Power was restored to affected clients within six minutes and the unit returned to service six hours later. In April tube failures in the fluidized bed heat exchanger (FBHE) forced the unit from service. Fifteen tubes in the FBHE were repaired and the unit returned to service approximately nine days later. In May the unit was again forced from service while broken tubes in a finishing heat exchanger were repaired during a five-day outage.

Unit 2 – was in service and capable of generating 227 MW on June 30, 2009. The unit was undergoing a scheduled outage for the overhaul of the unit at the start of the fiscal year. It returned to available status in mid-July on completion of its only scheduled outage. The unit was unavailable for service for 39 days in fiscal year 2009; 35 of these days were caused by eight forced outages. The Authority had to shed load at the onset of three of the eight forced outages. The longest that any of Authority's clients were without service following one of these trips was nine minutes. The unit's output was limited three times, each time for a different reason; the sum of the equivalent outage hours associated with these limitations was less than one day.

During the major overhaul from which the unit returned to service early in fiscal year 2009 AES-PR completed the replacement of the collector plates in the unit's precipitator, cleaned and inspected the boiler, repaired refractory, completed maintenance on electrical equipment, mechanical components, and fuel and ash handling and conveying systems. The unit was forced from service for five days during November for the repair of broken tubes in the FBHE. In February the unit was forced from service by opacity issues. During the outage the ID fans control system was reset and a malfunctioning turbine valve was cleaned and repaired. These repairs kept Unit 2 from available status for eight days. During an eight-day forced outage in March, seventeen tubes in a high-pressure feedwater heat exchanger were repaired. In mid-April the unit tripped from service following the failure of the fluidizing air blower. The unit tripped following the failure of the ash control valve forcing the Authority to shed load. The unit returned to service approximately 35 hours later following completion of repairs. The three other forced outages were caused by failures in instruments that monitored the secondary air fan and the generator; replacements were installed and each time the unit returned to service in three or fewer hours.

TRANSMISSION AND DISTRIBUTION SYSTEMS

The Authority's transmission and distribution systems is comprised of an island-wide network of power lines, switchyards, substations and electrical equipment that carry the electrical power from the production plants to serve the Authority's clients.

On an annual basis the Consulting Engineer's personnel visit and note the condition of approximately one-third of the Authority's 333 distribution substations and 45 transmission centers (TCs). In order to observe a representative sample, we select substations from among the 78 municipalities in the 26 districts served by the Authority. The scope of the inspections include a representative portion of the Authority's 230/115 kV transmission lines.

TRANSMISSION

The Authority's transmission system consists of high voltage power lines, switchyards and electrical equipment that carry the electrical power from the production plants to the dispersed substations, both the Authority's and privately owned substations, which serve the System load. The backbone of the transmission system is the 230/115 kV network that moves bulk power. The balance of the transmission system is the 38 kV lines and equipment that serve the whole island and also provide the submarine service to the islands of Vieques and Culebra. For reference when reading this section, a map of the Authority's 230 kVand115 kV transmission systems precedes the *Appendices*. The map shows the existing transmission system with the planned modifications to the systems through fiscal year 2014.

230 kV System

The existing 230 kV system is comprised of 364 circuit miles of transmission lines that encircle and sectionalize the island. The 230 kV system has two north-south corridors which divide the system into three principal loops—the western loop, the central loop and the eastern loop. Each north-south transmission line originates at a major production facility in the south and carries power to the load centers in the north.

The central loop has been in operation for many years. It was the first 230 kV transmission line to tie

the generating plants located on the island's south coast to the load concentrated in the San Juan metropolitan area via the Aguas Buenas TC south of the city. A parallel 230 kV line in the center of the island connects the Costa Sur and EcoEléctrica production units in the south with the Manatí TC located between San Juan and the Cambalache combustion turbine station on the north coast. The central loop is joined by east-west transmission lines connecting the Costa Sur units with the Aguirre plants in the south and a line on the north side of the island connecting Manatí to Aguas Buenas via Bayamón.

The western loop connects the Costa Sur and EcoEléctrica production units in the south with the Mayagüez switchyard and production units, on the west coast of the island, and from there to the northern cities of Aguadilla, Hatillo, and Arecibo. The western loop was completed in fiscal year 2002 following the construction of the segment connecting Mayagüez and the Cambalache TC. The loop increased the transmission system's capacity and reliability and improved the quality of electric service in the north-western municipalities.

The most recent expansion to the transmission system was the eastern loop that went into service during fiscal year 2006. The eastern loop was installed to support the load growth in the northeastern area of the island, complete the encirclement of the island by the 230 kV system, and improve the transmission system reliability and capacity by increasing the available transmission lines to move electrical power from the complex of generating plants in the south to major load centers in the north. The eastern loop runs from the large power production units in the southern plain at the Aguirre units in Salinas and the AES plant in Guayama to the eastern part of the island through Yabucoa and Río Blanco and terminating in Sabana Llana, southeast of the San Juan metropolitan area. Large sections of the new 230 kV eastern transmission line run along existing 115 kV rights-of-way. The project required the relocation of 16 miles of existing 115 kV lines between Río Blanco and Quebrada Negrito. The scope of the eastern loop project also included the expansion of the 230 kV facilities at the Sabana Llana and Yabucoa TCs.

The Authority is presently installing two new projects to expand the 230 kV transmission system These projects will improve the capacity and reliability of the transmission system, particularly in moving power from the generating plants in the south to the load centers in the north and enhancing voltage stability at the load centers. During most of fiscal year 2009 the Authority imposed operational constraints on the transmission system because all the Palo Seco units and the new San Juan Units 5 & 6 were not in full and reliable operation. Consequently new work adjacent to critical existing lines was deferred or rescheduled to periods of low demand, however, some work along new rights of way proceeded.

The first priority 230 kV transmission line project for the Authority will connect the Costa Sur Steam Plant and the EcoEléctrica, L.P. Cogeneration Plant, both of which are on the south side of the island, with the Cambalache combustion-turbine station near Arecibo, which is on the north side of the island. The total length of the line will be 38 miles, however, more than half of its length consists of upgrading existing 115 kV line to 230 kV, which will accelerate the construction schedule of the 230 kV line. The 115 kV line will be subsequently reestablished, as discussed below. The Authority plans to complete the 230 kV project in four years, beginning in fiscal year 2010. The Authority's current CIP shows spending on this project in the fiscal years of 2010 through 2013 will be $3.2 million, $8 million, $8 million, and $6 million, respectively. Presently, the line is scheduled for completion in fiscal year 2013.

The second priority 230 kV transmission line project is a new 50 mile long line being constructed between the Costa Sur Steam Plant in Guayanilla and the Aguas Buenas TC, located near the San Juan urban area load center. Construction of the line began in fiscal year 2003 and is scheduled to be completed in fiscal year 2015 at an estimated cost of $99 million. The expenditures for this project during fiscal year 2009 were $19.0 million, bringing the project to approximately 60% completion. Expenditures are estimated to be $8 million in fiscal year 2010, plus an additional $20.5 million through fiscal year 2014.

During fiscal year 2009 the Authority continued engineering and procurement for a new 230/115 kV transmission center in Ponce; construction is scheduled to start in fiscal year 2010. The project is forecasted to cost $6.0 million and has a target completion during fiscal year 2011. The new 450 MVA transmission center will be located in an existing 115/38 kV transmission center along the high capacity transmission line corridor east of the Costa Sur production units; this location will enhance the reliability and operational flexibility in the high voltage system for moving bulk power from the large generating units on the south side of the island. The

Authority plans to start work on the next new 230/115 kV transmission center in Mora, located in the northwest portion of the island, during fiscal year 2014.

115 kV System

The 115 kV system is comprised of 691 circuit miles of transmission lines that encircle and cross the interior of the island. The 115 kV system was the first high voltage transmission system put into operation on the island to improve the efficiency and reliability of the distribution of bulk power. The 115 kV lines and substations serve all the major load centers on the island. Many of the 115 kV transmission line corridors were subsequently used as rights of way for the 230 kV system lines as that system grew.

In its plans for the long term expansion and improvements to the 115 kV system, the Authority has prioritized a number of new and rehabilitation projects for 115 kV transmission lines, transmission centers and other components of the system. Given the scope, complexity, and cost of these projects, their execution typically spans many years between initial work and placement into service.

In fiscal year 2009 the Authority completed construction of a new $18.4 million 115 kV line project that provides an inter-connection between the transmission center at Juncos, which is presently fed from Humacao TC to its south, and the existing transmission line to its north that connects transmission centers at Rio Blanco and Monacillos. The Authority plans to start construction on two new 115 kV lines in fiscal year 2012. The first line is scheduled for completion in fiscal year 2014 and will feed the new, planned 115/38 kV Bairoa TC, north of Caguas. The next new line is scheduled for completion in fiscal year 2016 and will provide a second feed to the Hato Tejas 115/38 kV TC that is under construction; the line will run from the Palo Seco plants to the Hato Tejas TC in Bayamón.

The Authority's two priority projects for 115 kV transmission line work in fiscal year 2010 involve improvements to existing transmission lines. During fiscal years 2010 and 2011 the Authority has budgeted $18 million to upgrade an existing 115 kV transmission line between Caguas and Cayey to support the operation of the new transmission center under construction at Las Cruces, which is discussed below. The second project is the replacement of an existing 115 kV line between the Costa Sur plant and the Dos Boscas TC, located south of Arecibo. The initial phase of the work is the installation of the new 230 kV line discussed above, which is located along most of the same right of way. The replacement 115 kV line will be located in the existing right of way, but will have greater capacity; this project is scheduled to be in operation in fiscal year 2016.

In addition to the GIS substation in construction in the 115 kV San Juan urban loop discussed below, the Authority currently has identified eight priority projects associated with new or expansions to existing 115/38 kV transmission centers. The Authority has four projects for the construction of new 115/38 kV transmission centers and four projects to expand the capacity of existing transmission centers. Each of these transmission centers is close to an area of high or growing load, where it is necessary to reinforce the 38 kV system capacity and reliability by providing for additional operational contingencies in supporting the 38 kV system in those areas.

In fiscal year 2008 work began on a new 115/38 kV transmission center to be located in Hato Tejas, in the region of Bayamón. Work on the second new transmission center began late in fiscal year 2009. This transmission center will be in Las Cruces, located in Cidra south of Caguas. Both projects are targeted for completion in fiscal year 2011. The third new transmission center will be in Venezuela, near Rio Piedras in San Juan. The project work is scheduled to start in fiscal year 2011 and be completed in fiscal year 2014. The fourth new transmission center project will be in Bairoa, part of Caguas. This project is scheduled to start in fiscal year 2012 and be completed in fiscal year 2014. All four projects are rated at 150 MVA.

The Authority is presently working on two projects to increase the capacity of existing 115/38 kV transmission centers by extending the switchyard and installing a second 150 MVA transformer. These projects are at the Victoria TC, in Aguadilla, and the Canovanas TC, in the Carolina region; both are scheduled for operation in fiscal year 2010.

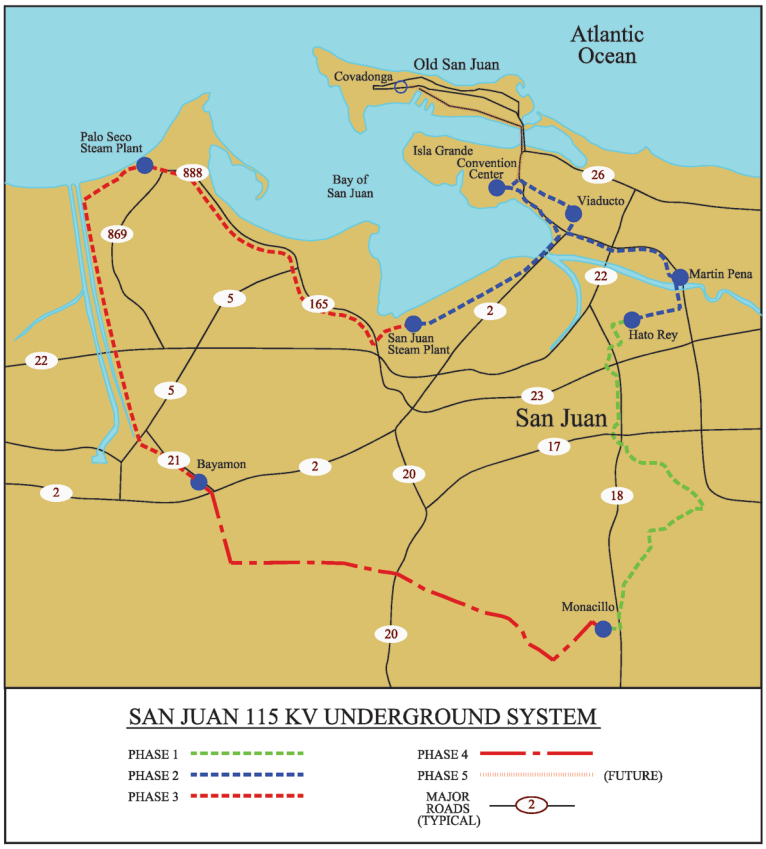
Concurrent with the new 450 MVA 230/115 kV Ponce TC project discussed above, the Authority will expand the capacity of the existing 115/38 kV Ponce TC by 150 MVA; construction is scheduled to start in fiscal year 2010 and be completed the following year. In fiscal year 2012 the Authority plans to begin installation of a second 150 MVA transformer at its Maunabo TC near the southeast corner of the island; completion is scheduled for the following year.

To protect the integrity of the transmission system in the San Juan urban area during and following extreme weather events, the Authority is installing four new 115 kV substations and a 30-mile underground loop of 115 kV transmission cables that will link the major components of its System in the metropolitan area. As shown on the 115 kV underground system map, the system can be fed through any of the four existing transmission centers and two steam plants which are interconnected by the new transmission loop. The principal function of the underground cable is to provide a robust measure of redundancy so that the Authority will be able to maintain continuity of service in San Juan's central business district, perhaps at partial load, in the event overhead lines are lost during a hurricane or other disaster. In addition, the cable will be available for back up service to the Authority's existing overhead transmission lines under normal circumstances. The scope of this project was prompted by the devastation caused by Hurricane Georges in fiscal year 1999. The Federal Emergency Management Agency (FEMA) reimbursed the Authority a total of $73 million of the project's cost of $195.8 million for the underground cable and ductbank scope of work.

The 115 kV underground work was installed in four major phases between fiscal years 2002 and 2008. All the underground 115 kV cable was fabricated using cross-linked polyethylene (XLPE) cable. While the XLPE cable was more expensive than cable insulated by oil or other chemical compounds it eliminated the possibility of environmental contamination if such compounds were to leak into the surrounding terrain.

The Authority incorporated provisions in the completed work for a future extension of the 115 kV underground system from the Isla Grande substation to the Covadonga substation in Old San Juan. This underground cable could provide increased load flow under normal and emergency conditions to the government buildings located in the Old San Juan area. The Covadonga 38 kV gas insulated switchgear distribution substation was constructed in a dedicated building that includes space for future 115kV equipment fed by an under ground duct bank.

The 115 kV underground system includes four new substations incorporating gas-insulated switchgear (GIS), providing for compact and enclosed substations. The first two new substations at Isla Grande and Martín Peña have been in service since fiscal year 2008. These substations were designed to support existing and anticipated load growth in their respective areas. The third and fourth substations are located at the San Juan and Palo Seco Steam Plants. These GIS switchyards will replace the old, existing switchyards that have been in operation since the plants went online in the late 1950's and 1960's. In conjunction with the 115 kV underground cable project, a new GIS switchyard will be constructed at each site for the terminations of the new 115 kV cable.



The new San Juan Steam Plant GIS switchyard has been designed to accommodate 850 MW, the existing units as well as the additional capacity of Units 5 and 6, which were placed in operation during fiscal year 2009. The switchyard GIS equipment has been purchased for this project and delivered to the island, but the original substation construction design was found to be too expensive. The Authority subsequently revised the scope of the San Juan Steam Plant GIS project to reduce the project cost. The revised project is budgeted at $62.5 million. Construction began in the third quarter of fiscal year 2009, with operation targeted for fiscal year 2013. In order to support initial operation of the new Units 5 and 6, the Authority installed a new, compact switchyard dedicated for Units 5 & 6; this switchyard is electrically tied into

the existing overhead 115 kV and 38 kV transmission systems.

The Palo Seco Steam Plant 115 kV GIS substation project completed construction in fiscal year 2009 at a cost of $65.7 million. Construction for this project began in fiscal year 2006, but subsequently the schedule for initial operation was revised to support the return to service of Palo Seco Units 3 & 4. The Palo Seco steam plant units suffered extensive damage to the electrical and control system during two fires in December 2006, and were already scheduled for major overhaul work. In view of the large scope of electrical work involved with the restoration of the Palo Seco units and the congested site, the Authority chose to realign construction work on the GIS project to coordinate with the repair and restoration work being performed on the steam plant units at the station. Operation of the GIS substation project coincided with the return to service of Palo Seco Unit 4 during fiscal year 2009, with Unit 3 scheduled shortly thereafter. Palo Seco Units 1 & 2 returned to service during fiscal year 2008 using a new 38 kV GIS substation adjacent to the new 115 kV GIS substation.

38 kV System

More than half of the Authority's transmission system circuit miles operate at 38 kV, which is considered its "sub-transmission" level. While most of the sub-transmission system is near load centers, it is also the primary transmission system to some of the island's most inaccessible interior regions.

The 38 kV system feeds two thirds of the Authority's distribution substation capacity and almost all of the private substations on the island. Given that the 38 kV system is an essential component in the Authority's transmission network, for many years the Authority has been pursuing a system wide rehabilitation program to upgrade the reliability and capacity of the 38 kV system. In addition, the Authority continues to invest in new 38 kV system lines, switchyards and expansions.

The scope of the rehabilitation work includes replacing old conductors with new, replacing aging wooden poles with steel poles and upgrading the system for forecasted local load growth. In some areas, certain sections of the rehabilitated 38 kV lines have been installed along new rights of way to facilitate the present work as well as future maintenance.

In fiscal year 2009 the Authority expended $17.0 million on 26 projects of 38 kV rehabilitation work; the five largest projects constituted approximately 70% of the total expenditures. These projects are located throughout the island and reflect the extent of the 38 kV system. The Authority has budgeted $21.3 million and plans to work on 40 rehabilitation projects in the 38 kV system during fiscal year 2010. The largest project in 2010, however, accounts for approximately one-quarter of the fiscal year's 38 kV rehabilitation budget. This project involves upgrading the 38 kV lines in the north-western area of the island that are served by the Victoria TC, which increased its transformer capacity and the new additional generation at the Mayagüez plant.

The Authority expended $1.8 million during fiscal year 2009 on new aerial 38 kV lines, which is similar to the budget for fiscal year 2010 for these expansions. There were 14 active projects during fiscal year 2009; the Authority's budget has funds for seven projects in fiscal year 2010.

The 38 kV system also includes more than 50 miles of underground cable in mostly urban areas. In response to civic and business leaders requests, the Authority is expanding the scope of the underground cable in urban and industrial areas. During fiscal year 2009 the Authority expended $1.6 million on new and expansion underground 38 kV projects. The largest underground project in fiscal year 2009 was the new underground line between two key substations in the Guaynabo district, in San Juan. The underground line connecting the Caparra and Cachete sectionalizers in Guaynabo is the highest priority underground 38 kV line and is scheduled to be completed in fiscal year 2011 at a total cost of $7.6 million. Work continued during fiscal year 2009 on an underground line from the Sabana Llana TC feeding an existing substation located approximately two miles away in the urban area of Carolina; the project is scheduled for completion in fiscal year 2010. The third project is the underground feeders in the new Parque Tecnológico Las Américas (Technology Park of America) southwest of Arecibo; approximately one half of the cost of the 38 kV work is being underwritten by the public and private project developers. The Authority plans on expending $7.0 million on this project during the coming fiscal year and an additional $3.0 million in the following two fiscal years.

The submarine cables feeding the islands of Vieques and Culebra are part of the 38 kV system. Recent severe erosion of the beach on Vieques where the

submarine cable makes landfall has forced the Authority to extend the cable and relocate the termination structure. This is a priority project for the Authority that is budgeted at $1.5 million and is scheduled for completion in fiscal year 2010.

During fiscal year 2009 the Authority expended $2.0 million on continuing work on a new 38 kV GIS substation at the Parque Tecnológico Las Américas. As discussed above the substation will support a new industrial complex now under development. The Authority has budgeted $3.7 million to complete this project in fiscal year 2010.

In fiscal year 2009 the Authority expended $1.3 and $1.6 million respectively on two new, ongoing 38 kV sectionalizer projects. The first sectionalizer is in Aguadilla and the second is part of the expansion of the substation at Factor, discussed below. Both are scheduled for completion in fiscal year 2010.

Transmission Plant Capital Improvements

The transmission plant funding forecasts in the Authority's current CIP address a wide range of improvements covering the entire transmission system. Transmission capital expenditures in fiscal year 2009 amounted to $91.5 million. The Authority is planning to spend $117.2 million on capital improvements to its transmission system in fiscal year 2010: $79.8 million for expansion projects and $37.4 million for rehabilitation projects. The Authority plans to spend $469.1 million on its transmission system over the next five fiscal years. Details of these expenditures are discussed in the *Capital Improvement* Program section and are itemized in *Appendix X, Details of Capital Improvement Program* and summarized in *Appendix VI, Capital Expenditures.*

DISTRIBUTION

The Distribution System is the final link between the Authority's production plants and Transmission System and its clients, with the exception of the small number of commercial and industrial clients who purchase power at the transmission level. The Distribution System includes Authority owned substations that reduce the power from transmission voltage to the level at which it is locally distributed. The lines, poles, transformers, and appurtenances of the Authority's distribution system are installed along both city streets and country roads as well as along the Authority's rights-of-way. Service drops from the distribution lines and meters complete the connection to clients' premises.

Selected 13.2 kV Projects

The Authority has a long-standing program in place to upgrade its primary distribution level to 13.2 kV. The higher voltage is a cost effective method that enables the existing conductors to carry more load, while updating older distribution equipment such as transformers, switches, capacitors and reclosers. In addition, operating at 13.2 kV reduces line losses and allows for longer circuits runs, thereby providing more flexibility in making system interconnections.

The Authority makes on-going investments in new distribution substations to support new and increasing load, such as in areas with increasing residential construction, and to improve system performance. The Authority has standardized on two sizes of permanent substations based on the transmission system supply voltage. This standardization expedites the engineering, procurement, and construction cycle, increases flexibility in potentially utilizing equipment as spares, and provides a cost effective installed capacity margin for load growth. In situations where the Authority needs additional substation capacity on an interim basis or with short lead times, the Authority installs temporary substations that are standardized unitized metal clad equipment, which can be relocated as required.

During fiscal year 2009 the Authority placed into service a new 13.2 kV substation at Mora in Isabela. Work continued on a second new 13.2 kV substation at Factor in Arecibo which is scheduled to be completed early in fiscal year 2010; the scope of work includes a new 38 kV sectionalizer which will be placed in service concurrently with the substation. The Authority plans to begin work on four new permanent 13.2 kV distribution substations in fiscal year 2010. The first project is a new substation at Yabucoa in the Caguas region that is scheduled for completion in fiscal year 2011. The following year the Authority plans to complete the new substations at Rio Bayamón II and Hato Tejas both in the Bayamón region and Santa Isabel in the Ponce region. In fiscal year 2013 the Authority plans to complete one new substation, with three more scheduled for completion in fiscal year 2014. The total amount budgeted for the construction of these substations is $37.4 million for the five years through fiscal year 2014.

In addition to expansions and new distribution substations, during fiscal year 2010 the Authority plans to replace the transformer in the Buen Pastor substa-

tion in the San Juan region to increase the capacity from 22.4 MVA to 44 MVA.

The Authority owns 18 portable distribution substations that enable them to perform substation maintenance with minimal or no interruption of service, to speed recovery after a substation failure, and for enhanced operation during line clearance constraints. The portable equipment ranges in size from 1.5 MVA to 45 MVA at 38 kV and 115 kV, and includes two capacitor banks at 38 kV 18 MVAR.

In compliance with a settlement with the municipality of Ponce, the Authority is improving the distribution system in the historic district of Ponce. The project involves upgrading the existing overhead 4.16 kV system to a 13.2 kV underground distribution system. The underground work in the historic district is being coordinated with the telephone company and the water and sewer utility who are also concurrently relocating buried utilities in the same district. The scope of the entire project will be executed in four sequential phases to minimize disruptions to the neighborhoods and local traffic. The first phase of the work was completed and placed in service in fiscal year 2007 at a total cost of $21.1 million, of which $12 million was born by the Authority. The second phase of the work is budgeted at $18 million, with $10 million being the responsibility of the Authority. This phase began work in fiscal year 2008 and completion is scheduled in fiscal year 2010. Design for the third phase began last fiscal year, construction is scheduled to start early in fiscal year 2010, with completion in fiscal year 2012. Work on the fourth phase is targeted to begin following completion of the third; the final phase is targeted for completion in fiscal year 2012. The total cost for all the work is estimated to be $56 million, with the Authority's portion costing approximately $33 million.

Distribution Plant Capital Improvements

The Authority's capital expenditures on the distribution system amounted to $105.0 million in fiscal year 2009. The Authority is planning to spend $75.3 million on capital improvements for its distribution system in fiscal year 2010: $17.0 million for expansion projects, $58.3 million for rehabilitation projects and other distribution expenses, such as remote automated meters, line transformers, breakers, sectionalizers, and reclosers. The remote automated client meters discussed below have been a long term capital commitment by the Authority and they account for 19% of the Distribution CIP budget for fiscal year 2010. The Authority plans to spend $397 million on its distribution system capital improvements over the next five fiscal years.

AUTOMATED SYSTEMS

The Authority uses an integrated computerized system that provides information management tools to improve the effectiveness and efficiency of its operation and maintenance of the transmission and distribution systems. The Authority's data management system integrates a Work Management System, a Geographic Information System and an Outage Management System into an Integrated Resource Management System that is known by its Spanish acronym of AIRe (Administracion Integrada de Recursos).

The AIRe system is structured to maintain its databases as well as interface with existing computerized systems in other Authority divisions such as finance, human resources, and payroll. Some of the benefits of the AIRe system are: improved client service; reduced O&M expenses; improved emergency response; better planning; improved and consistent engineering/design and estimating practices; archived maintenance records; and, real-time system status reporting.

To develop and implement the AIRe system the Authority worked with leading suppliers of asset management system software. The expenditures on the contract for the lead software development were $30.2 million through initial installation. Since then the Authority has established maintenance contracts with the firms involved in the AIRe system to provide continuity and upgrades. The total cost of the maintenance contracts has averaged less than $1 million per year.

The Work Management System (WMS) component of the AIRe system has been in service in all of the Authority's districts since 2001. During fiscal year 2009 the Authority began implementing a major upgrade to the software system, scheduled to be completed in two years. Concurrently the WMS will include the integration of the GIS, discussed below. The WMS tracks the progress of all construction and maintenance work from start to completion in real time. The functions of the system include estimating, engineering, scheduling, required approvals, the generation of bills of material of approved equipment in accordance with Authority standard designs, and the accumulation of labor and material costs for each project. Engineers using mobile laptop computers with Authority design standards can start local project work in the field. When the proj-

ect is completed the system provides for incorporating any differences between the design and as-built installation and updates both the Authority's existing inventories and its Continuing Property Record (CPR), which is a detailed list of the Authority's Plant-in-Service.

The Geographical Information System (GIS) component of the AIRe system is a comprehensive geospatial model of the entire transmission and distribution systems including an inventory of all components. The GIS database is designed to interface with the WMS and the Outage Management System, as well as providing an engineering tool for modifications, new work and circuit analyses. Completing the GIS was a major task since the Global Positioning System (GPS) coordinates of every pole on the island had to be plotted and all the associated equipment physically inventoried. The Authority has recently expanded the scope of the GIS to include validating the location of client meters to improve the precision of the Outage Management System discussed below. The Authority estimates the client meter validation activity will be completed in fiscal year 2011. The GPS coordinate data are utilized with a one-meter resolution satellite map database of the entire Commonwealth that was developed by a Puerto Rican interagency governmental group.

The Outage Management System (OMS) component of the AIRe system has been in island-wide operation since the end of fiscal year 2008. The OMS is designed to improve the Authority's recovery efforts following a hurricane or tropical storm by generating: a damage assessment report based on data received from various system transponders and the Customer Information System; a complete inventory of equipment needing replacement; maps of all areas affected by the outage(s); and, an up-to-the-minute report of the System's status. When the restoration work is underway, the AIRe system monitors and records all of the labor and material costs. The installation of replaced equipment will then be used to update the Authority's CPR.

In conjunction with the OMS system the Authority expanded the use of an Automatic Vehicle Location (AVL) system to approximately 120 repair vehicles during the past fiscal year. The AVL system is capable of providing the real-time location of any Authority vehicle fitted with the GPS receiver and communication link to the Authority's local dispatch center. Vehicle location information has been useful for the local dispatch in reducing travel time to problems and routing assistance to work crews if required. The AVL also enhances the safety of the crews by providing their location whenever it may be needed, such as during wide area power restoration work. The initial experience with the AVL system has been favorable and the Authority is evaluating deployment in all emergency vehicles.

In addition to the AIRe system, in fiscal year 2000 the Authority began the island-wide installation of an Automated Meter Reading (AMR) system. When it is fully installed, the AMR will enable the Authority to remotely status all residential client meters, in addition to all other clients served at 13.2 kV and below. The target cost for the AMR system is approximately $200 million for the initial installation at all designated clients. The program consists of installing new design digital meters for all new clients as well as actively replacing old and defective meters. As of June 30, 2009, automated meters had been installed in approximately 90 percent of the target total of more than 1.4 million meters. The AMR system digital meters are significantly more accurate than the analog meters they replaced. The system being installed utilizes a proprietary technology, which communicates between meters and remote controllers by superimposing a frequency modulated signal on the Authority's existing distribution lines between the client meter and the Authority's substation. Because it uses the electric power wires, this technology's performance is not impaired by the island's varied terrain.

Communication between the AMR system central processor and the individual installed meters is through dedicated transformers and communication equipment installed in the substation serving the associated client's meter. The processed signals from the AMR substation equipment are routed to the central processor via the Authority's existing fiberoptic or microwave systems. The project calls for the installation of AMR communication equipment at all the Authority's substations throughout the island by the end of fiscal year 2011. As of the end of fiscal year 2009, the Authority had installed this AMR equipment at more than 94% of its substations.

The Authority's early experience with the AMR meters exposed weaknesses in the meter's resistance to tampering. In response the Authority toughened its meter specifications and began thermally spot sealing the digital meter's plastic case to deter tampering, or at the very least leave evidence of tampering if the meter were inspected. In addition, the Authority formed a multi-discipline technical group

to identify features to enhance the tamper resistance of the AMR meters. Although the Authority now buys meters with the most robust anti-tampering specifications commercially available, even the newest meters have proven susceptible to tampering with powerful magnets. In the second half of fiscal year 2009 the Authority significantly increased its theft detection and prevention program. Amongst other detection techniques, the program utilizes the comparison of local/temporary meters on the distribution lines versus the aggregate of the individual served meters, a comparison of a client's present electricity usage versus historical data, and a toll free hot line for anonymous reporting of suspect electricity theft. Based on experience in fiscal year 2009, the Authority anticipates the theft recovery program will generate considerable additional revenues and help deter further theft. As discussed in the *Legal Affairs* section the Authority has established legally binding administrative processes to recover contested billings for theft from responsible clients.

Although they are not among the AMR system features now being installed, the AMR has the capacity to incorporate at a later date the ability for the Authority to simultaneously monitor and control the performance of key components of its distribution system. By controlling such devices from a central location, the Authority would be able to enhance its capability to control load flow, manage restoration of service from an outage, and improve operational power factor. If added, this type of control could reduce operating costs, improve client satisfaction, and facilitate Demand-Side Management & Energy Conservation (DSM & EC) programs by allowing the utility to control its clients' energy use. The AMR system can also be expanded to provide real time electrical power consumption data to support analyses of operational performance and time based pricing structures that may be evaluated in the future.

Now that the Authority has completed the installation of the Work Management System in each district and implemented the interface with the Customer Information System, Customer Services operators can now switch between their billing system and the Work Management System while speaking with clients. During emergencies, all the commercial offices located across the island are integrated into the Work Management System, allowing trouble orders to be immediately generated electronically.

The implementation of these automated systems has allowed the Authority to consolidate many of its Customer Service centers. The new consolidated offices improve operational efficiency and are a way to improve client satisfaction since the new service centers are staffed 24 hours a day seven days a week.

MAINTENANCE

The Authority generally maintains its transmission and distribution equipment using a time-based system. In some cases the maintenance intervals have been modified to meet the challenging tropical environment or relevant operating experience. As an example of routine periodic inspections, the Authority performs infrared inspections of all substations and switchyards twice a year. The infrared inspections are used to identify "hotspots" which are faulty connections that are overheating and are likely candidates for failure. In addition to performing electrical and mechanical testing, the equipment is painted on a periodic basis to help prevent corrosion.

The Authority's inspection and maintenance program for high voltage electrical equipment is based on the criticality of the equipment's service, with the scope and frequency of the inspections and maintenance guided by the manufacturer's standard recommendations. Main power and transmission transformers are inspected on a two year cycle, while substation transformers follow a four year interval. The Authority takes oil samples annually from all high voltage transformers in an effort to identify internal deterioration before it leads to failure. The Authority's oil analysis program relies on a recognized industry consultant's recommendations, coupled with its own operating and maintenance experience, to perform more frequent monitoring or eventually repair. As many major transformers approach their design service life this program has become increasingly important in maintaining the system operating reliability.

The inspection and testing frequency for other high voltage equipment in the maintenance program include: gas circuit breakers—six years; oil circuit and vacuum circuit breakers—four years; and protective relays—no more than three years for calibration and testing, with relays protecting major equipment such as transmission transformers tested more frequently based on when the equipment is out of service.

Recently the Authority's transmission towers have been subject to sporadic vandalism and the theft of aluminum structural bracing members for their scrap metal value. On one occasion removal of these components precipitated a transmission tower collapse, transmission line damage and subsequent loss of service in the surrounding area. While police

apprehended the thieves involved in the tower collapse, the Authority has increased inspections of all transmission towers using both the helicopter patrols and inspections from the ground. Any deficiencies identified in these inspections are repaired on a priority basis.

Transmission system maintenance expenses, shown in *Appendix III, Detail of Operating Expenses,* totaled $33.0 million in fiscal year 2009. For fiscal years 2010 through 2014 the Authority has forecasted expenditures in millions of dollars of $34.5, $30.9, $30.9, $30.8, and $30.7, respectively. Among these expenditures are funding for tower maintenance, tree trimming, insulator replacement, helicopter patrolling of transmission lines, and right of way management. The costs associated with the transmission system portion of substation maintenance are also included in these budgeted expenditures.

Distribution system maintenance expenses, also shown in *Appendix III, Detail of Operating Expenses,* totaled $67.3 million in fiscal year 2009. The budget for fiscal year 2010 includes $70.3 million for distribution system maintenance expense. For fiscal years 2011 through 2014 the Authority has forecasted expenditures in millions of dollars of $66.3, $66.1, $66.0, and $65.9, respectively. These expenditures include distribution system related expenditures similar to those described under transmission system maintenance expenses.

The Consulting Engineers believe the planned expenditures for maintaining the Transmission and Distribution Systems are adequate.

TRANSMISSION AND DISTRIBUTION SYSTEMS RELIABILITY

The principal guideline in the operation of a utility electric system is to continuously balance the real time demand for electricity (the load) and the simultaneous production of power while maintaining regulation of the system's voltage and frequency. The electric system is designed to meet this requirement across a wide range of operating conditions, which include loss of an operating transmission line or other key system component. Analyses of these design conditions establish the required redundancies in the system and operating criteria. Consistent with industry practice, the Authority has designed the entire transmission system to maintain continuous operation with at least one contingency event (loss of an operating component) and two contingencies for critical lines that move power from the central production plants.

Reliability Indices

Reliability standards have been in place within the North American electric utility industry for many decades. Following recent wide spread power losses in America, such as the Northeast blackout in August 2003, the electric power industry and its regulators have reaffirmed the importance of reliable service to support the balance of the economy. This was reinforced in the Energy Policy Act of 2005, which called for mandatory reliability standards for the interstate bulk power systems. The Authority's experience is consistent with the industry in that while the notorious blackouts are caused by the transmission systems, most interruptions to client service are caused by problems in the local distribution system.

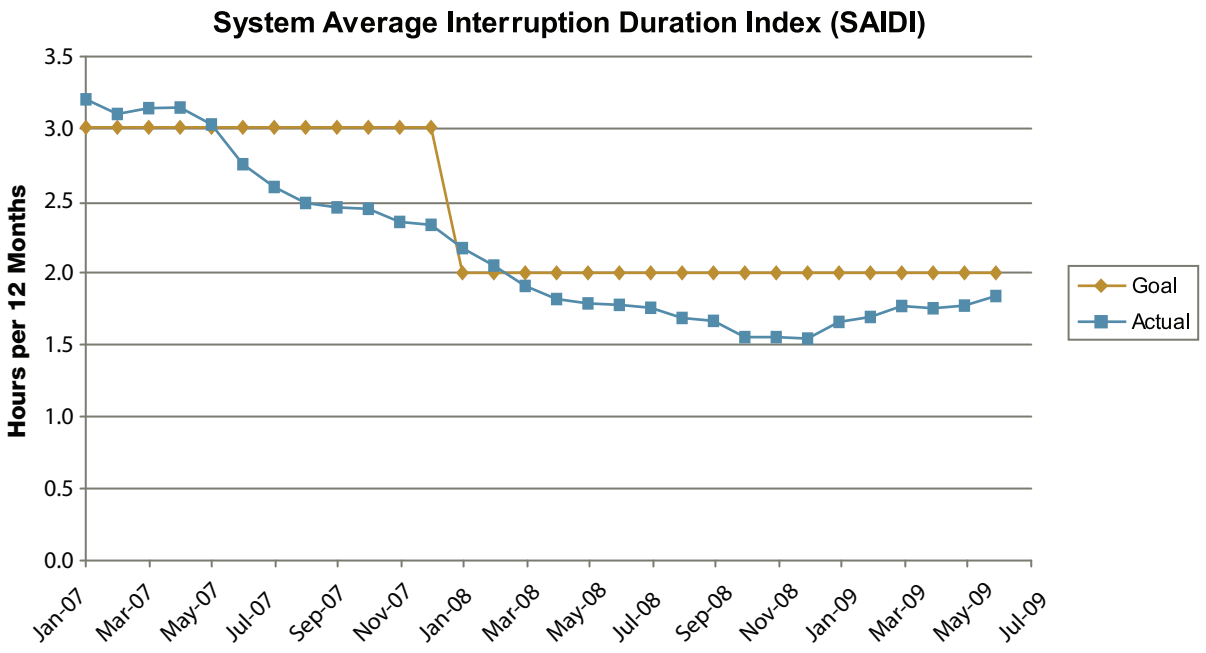
Two industry criteria generally accepted for measuring an electric system's reliability of service to its clients are the following:

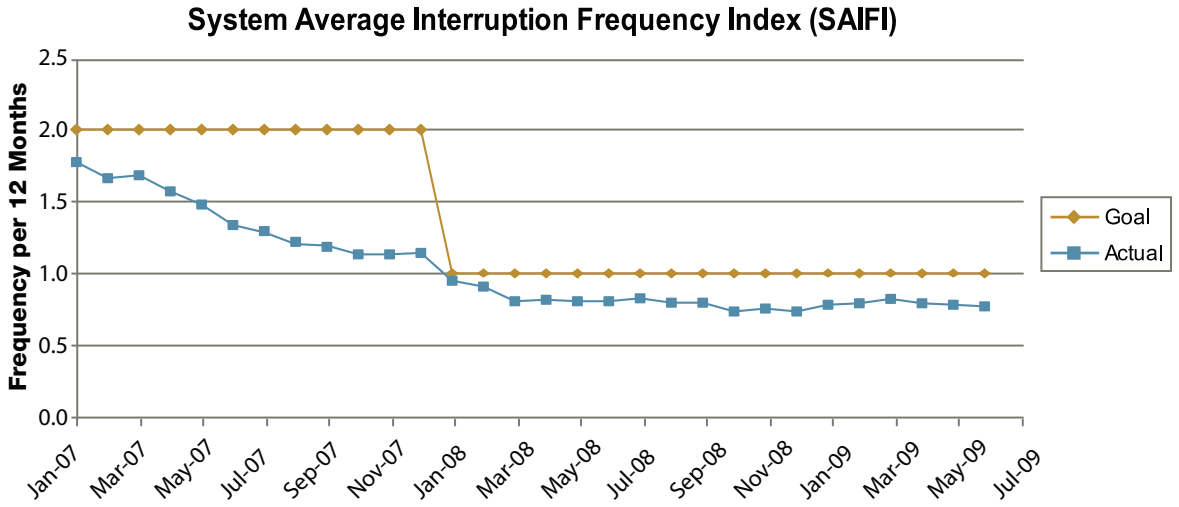
System Average Interruption Duration Index (SAIDI) – The average duration of sustained service interruptions per client occurring during the preceding twelve-month period. It is the average time a typical client was without power over a rolling twelve-month period. The average is determined by dividing the sum of the durations of all sustained client interruptions by the total number of clients served. The Authority reports its SAIDI duration statistics in hours.

System Average Interruption Frequency Index (SAIFI) – The average frequency of sustained interruptions per client occurring during the preceding twelve-month period. It is calculated by dividing the total number of sustained client interruptions by the total number of clients served.

SAIDI and SAIFI indices take into account only sustained outages; they do not reflect momentary interruptions or voltage irregularities, which can affect sensitive electronic equipment. For both SAIDI and SAIFI, lower index values indicate better client service, i.e. shorter and fewer service interruptions.

Throughout the electric power industry the general procedure for calculating reliability indices has been implemented by most utilities with their own specific adjustments to reflect their service conditions. The Authority's SAIDI and SAIFI data include only outages longer than fifteen (15) minutes and exclude major events, such as the effects of tropical storms/hurricanes and disruptions from multiple contingencies.





The graphs above show the Authority's SAIDI and SAIFI data over the 30 month period ending on June 30, 2009 to provide some perspective on the short term trend of these indices. Starting in January 2007 and again in January 2008, the Authority lowered its goals for both SAIDI and SAIFI to reflect the Authority's objectives in continuing to improve client service. The SAIDI goal for calendar year 2007 was 40% less than previously, while the SAIFI goal was one-third less than previously. The SAIDI goal for calendar year 2008 was lowered an additional 33% and the concurrent SAIFI goal was cut in half. These new performance targets coincided with the Authority's reinvigorated tree trimming and vegetation control programs that specifically address a major cause of service interruptions. The scope of the Authority's program includes both transmission and distribution lines, as well as public education of appropriate plantings located under overhead power lines. The Authority had previously lowered its reliability goals in January 2002.

The Authority's current SAIDI and SAIFI goals are only 40% and 33%, respectively, of what they were in calendar year 2006. These lower goals are more challenging to achieve and maintain, consequently the margin between the goals and actual performance has shrunk.

The average total duration of a client's sustained interruptions during the past fiscal year, as shown above in the Authority's 12-month rolling average of SAIDI, was consistently below the Authority's current goals and tended to remain in a relatively narrow range. This past fiscal year, however, may have marked the end of a nearly steady decrease in SAIDI statistics over the preceding six years during which the average interruption duration dropped by two-thirds.

During fiscal year 2009 the twelve-month rolling average of the number of sustained outages per client was stable and below the Authority's SAIFI goals for the year. In the eight years following fiscal year 2001, the frequency of service interruptions measured by SAIFI statistics peaked in the second quarter of fiscal year 2005. The SAIFI values in the past fiscal year were approximately one-fourth those in fiscal year 2005. Similar to the SAIDI statistics discussed above, fiscal year 2009 may have marked the end of the almost constant decrease in the frequency of interruption over the last four years.

As the Authority reduces the outages caused by trees and vegetation, one key to further improving the Authority's reliability performance will be the identification of the cause of service interruptions. The potential integration of the Customer Information System, AIRe and Automated Meter Reading systems may allow more detailed analysis of reliability data. In addition, it would be possible to acquire data on an individual client's actual experience rather than relying on composite averages.

GENERAL FACILITIES

The budget for capital improvements for the General Plant encompasses General Land and Buildings and Equipment. The budget for General Plant capital improvements during fiscal year 2009 amounted to $71.0 million; actual expenditures during the past fiscal year were $37.5 million. The largest reductions in capital expenditures during fiscal year 2009, compared to the budget, were in expenditures for land and rights of way, information technology equipment and systems for client services and other miscellaneous equipment. As shown on *Appendix X Details of Capital Improvement Program,* the expenditures for General Plant for fiscal years 2010 through 2014 are forecasted to be $24.2 million, $35.2 million, $44.0 million, $59.6 million, and $45.5 million, respectively.

The extensions and improvements planned for fiscal year 2010 include $7.8 million for General Land and Buildings. Expenditures within this category are for the acquisition of transmission rights of way, land for planned expansions, improvements to the Authority's warehouses, workshops, offices, buildings, and grounds. The budgets for new technical buildings and warehouses in the Capital Improvement Program have been deferred until fiscal years 2012 and 2013 respectively.

The total expenditures for Equipment in fiscal year 2009 were $15.2 million, in comparison to a budget of $26.4 million. For fiscal year 2010 the total Equipment budget is $16.4 million; this is comprised of four budget subgroups, as follows: The Computer Equipment budget for fiscal year 2010 is $5.4 million—$3.1 million is allocated to the Customer Service systems and $1.2 million for improvements to the fiberoptic system. The Transportation Equipment budget is for repairs or improvements to the Authority's aircraft and purchase and replacement of the Authority's vehicles; the budget for fiscal year 2010 is $6.6 million. The Communication Equipment budget is $970,000 for fiscal year 2010. The last Equipment subgroup is Other Equipment, which has a budget of $3.5 million for fiscal year 2010. The scope of this subgroup spans a wide range of equipment including specialized power quality monitoring equipment, vehicle repairs tools, small construction tools and miscellaneous tools used for the installation of distribution lines.

CONDITION OF THE SYSTEM'S PROPERTIES

The Consulting Engineers visited and noted the condition of each of the Authority's steam-electric generating facilities three or more times during fiscal year 2009 and also visited the other production facilities at least once during the fiscal year. In addition, we also visited and noted the condition of approximately one-third of the Authority's more than three hundred and seventy transmission centers and distribution substations. In the course of these visits we observed other property in the production, transmission, distribution, and general plant functional groups.

In conjunction with our field activities, we have reviewed various maintenance reports of the Authority, specific maintenance activities, and the planned actions for the next fiscal year. We have also reviewed reports submitted by manufacturers' representatives.

In the opinion of the Consulting Engineers, the properties of the System are in good repair and sound operating condition. The Consulting Engineer notes that Palo Seco Steam Plant Units 1 & 2 returned to service in fiscal year 2008 following a serious fire in December 2006. Palo Seco Unit 4 returned to service during fiscal year 2009, however it developed performance issues following its return to service and its output was limited at the end of fiscal year 2009. Unit 3 was scheduled to return to service early in fiscal year 2010.

CURRENT FORECAST

During the last third of every fiscal year the Authority develops a forecast entitled *Presupuesto de Ingresos* (Revenue Budget) that contains detailed short-to-intermediate-term projections of energy sales revenues, number of clients, fuel prices based on Energy Information Agency (EIA) projections; the forecast also includes long-term generation and long-term peak demand. This annual report references the Authority's forecast dated April 2009 as the "Current Forecast." The remainder of this section will describe the results of these forecasts and the methodologies used in their preparation.

The preparation of the Current Forecast is timed so that its projections may be used to develop short-term (1-2 years), intermediate-term (3-5 years) and long-term projections (6 years and beyond) of various financial and operational parameters. The short-term financial projection is used for the Authority's Annual Budget of Current Expenses (Annual Budget) for the ensuing fiscal year that begins on July 1st. The intermediate-term revenue projection is utilized to establish the Authority's needs for capital improvements and the projected sales revenues, which are used to evaluate its ability to meet the necessary covenants of its Trust Agreement regarding forecast revenue to projected debt coverage. The long-term projection of peak demand and available capacity through 2030 is used to plan for the addition of generating capacity in the future. (See *Capacity Planning.*)

Since the Current Forecast was prepared before the end of the fiscal year, it was based on actual kWh sales from July 2008 through February 2009. Energy sales for the balance of fiscal year 2009 were estimated by service class based on extrapolations of kWh sales for the three-year period of 2006 to 2008 and year-to-date data in fiscal year 2009. Generation requirements are derived from sales projections, adjusted to reflect system operating losses. The forecast methodology reduces data to a daily basis to allow adjustment for leap years.

The short-term and intermediate-term forecasts project estimated sales, revenues, number of clients, generation, and maximum demand on a monthly basis for the remainder of fiscal year 2009 and for all of fiscal year 2010 and on an annual basis thereafter through fiscal year 2014. Projections of fuel costs are also provided through fiscal year 2014. The long-range forecast projects annual generation (in GWh) and peak demand (in MW) is projected through fiscal year 2030.

The projected revenues in the Current Forecast are derived from the forecast energy sales by classification using existing base rates and the appropriate adjustment charges for the cost of purchased power and fuel. The revenue projections also take into account the residential subsidies but do not include the industrial and hotel subsidies. The Authority's forecasted revenues and payment obligations are discussed in the *Financial* section.

In the preparation of the Current Forecast the Authority typically reviews analyses of the Puerto Rico economy that are prepared each year by three independent economic consultants. The three consultants are Econometrica, Inc. (ECO); the Inter-American University – IHS Global Insight (IAU-GI); and the Commonwealth of Puerto Rico's Planning Board (Planning Board). The Authority uses the economic indicators projected by these economic consultants in these analyses in the preparation of its Current Forecast. In view of the uncertainties in the economic forecasts, the Authority generally uses the least optimistic five-year intermediate term energy sales projections for financial planning purposes and the most expansive projections for long-range capacity and operational planning. This year, however, the Authority selected the Planning Board projections because they were the least expansive for the budget year 2009-10 and effectively match the least expensive projections for the following two fiscal years. (See *Econometric Factors* section below.)

For the last two decades the short-term energy sales projections in the Authority's Current Forecasts have typically been conservatively close to actual performance; these were during a period of almost continuous electric sales growth only interrupted by the impact of hurricanes. Since fiscal year 2006, however, short-term consumption forecasts have understated the actual decline in consumption. To improve the accuracy of their projections, last year the Authority revised the modeling of residential and industrial class consumption to reflect the clients' sensitivity to the price of electricity.

Although the least expansive forecast was used to project the electric energy consumption in each of service class for fiscal year 2009, electric sales were actually 5.5% less than the previous year, compared to a projected decline of 1.3%. Additional discussion of fiscal year 2009 performance can be found in the *Short-to-Intermediate Term Energy Sales Forecast* section.

ECONOMY OF PUERTO RICO

Since the present depressed state of the economy of Puerto Rico is unprecedented in recent decades, economic forecasting for the island is currently difficult and more uncertain. The demand for electric energy in Puerto Rico has historically tracked the island's evolving economy and its attendant economic development. Puerto Rico's economy has evolved from primarily an agriculture economy in the early 1900s to one dominated by manufacturing in the 1940s through the 1970s and, finally, moving to a mixed economy largely comprised of the manufacturing and service sectors over the past three decades.

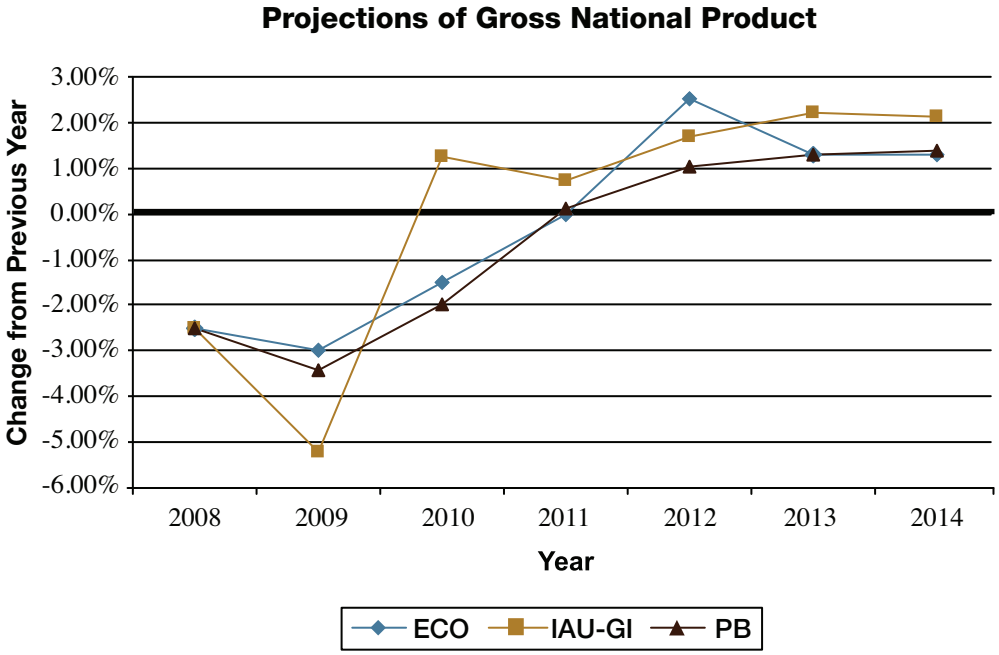
The Planning Board is the official Commonwealth agency that collects and reports the principal macroeconomic indicators utilized in the Current Forecast, which are the Gross Domestic Product (GDP), and the Gross National Product (GNP), of the Puerto Rico economy. The Planning Board's macroeconomic indicators depicted in the Current Forecast for fiscal year 2006 and 2007 were revised and fiscal year 2008 is preliminary. As measured by the GNP the Puerto Rican economy was robust in the three fiscal years ending in 2005, subsequently the economy grew marginally by 0.5% in fiscal year 2006 and contracted by 1.9% in fiscal year 2007 and 2.5% in fiscal year 2008. The Planning Board's preliminary estimate for the GNP is that it contracted by 3.4% during fiscal year 2009. For fiscal year 2010 the Planning Board initially projected a contraction in the GNP of 2.0%, however, with the implementation of the Federal Economic Stimulus Plan and economic measures, such as the Employment Reduction Plan and the Economic Stimulus Plan, to be implemented by the Commonwealth Government of Puerto Rico, the Planning Board revised its projection that the GNP would grow marginally by 0.1% in fiscal year 2010, 0.9% in 2011 and 1.0% in 2012. The chart below reflects the earlier Planning Board projections that were utilized in the Current Forecast.

The following chart shows the projections of the Gross National Product for Puerto Rico by the Authority's three economic consultants for fiscal years 2009 through 2014.

ECONOMETRIC FACTORS

The Current Forecast is based on econometric models, which attempt to correlate the future consumption of electricity with recent consumption data, industrial class power costs and selected economic indicators. This year, as in most years, the Authority used three economic consultants to provide forecasts of these macroeconomic indicators. As mentioned earlier, the three consultants were Econometrica, Inc. (ECO); the Inter-American University–Global Insight (IAU-GI); and the Commonwealth of Puerto Rico's Planning Board (Planning Board).

To establish the sales forecasts in the Current Forecast for the base fiscal year of 2009, the



Authority's model used actual data through February 2009 and estimated data for the balance of the fiscal year based on correlations with year-to-date data and extrapolation of data from the prior three years.

The projected energy sales by client classification data were developed using historical data since 1983 and selected economic indicators to March 2009. These macroeconomic indicators are:

- Gross Domestic Product (GDP), used in part to forecast residential and commercial kWh sales.
- Gross National Product (GNP) used as a factor in forecasting industrial kWh sales.

In developing the Current Forecast the Authority uniformly employs the economic indicators from each economic consultant. The resulting power sales over the five-year intermediate term forecast period are summarized below (CAGR is the compound annual growth rate):

PROJECTIONS OF TOTAL GWH SALES

Fiscal Year	ECO	Percent Change	IAU-GI	Percent Change	Planning Board	Percent Change
2008	19,601.6		19,601.6		19,601.6	
2009	18,574.3	-5.24%	18,574.3	-5.24%	18,574.3	-5.24%
2010	18,087.2	-2.62%	18,115.1	-2.47%	17,929.0	-3.47%
2011	17,729.2	-1.98%	17,938.8	-0.97%	17,739.2	-1.06%
2012	17,612.7	-0.66%	17,908.7	-0.17%	17,667.1	-0.41%
2013	17,468.3	-0.82%	18,036.1	0.71%	17,700.5	0.19%
2014	17,314.1	-0.88%	18,279.7	1.35%	17,826.8	0.71%
5-year CAGR		-1.40%		-0.32%		-0.81%

Generally the Authority would have used the ECO projections in its Current Forecast since these produced the lowest growth rate, negative 1.40%, in total energy sales over the future five year period 2010-2014. This year, however, the Planning Board's forecast was used because it was least expansive in total energy sales for the 2010 budget year with negative 3.47%. In addition, the sales projections based on the Planning Board were within 0.05% and 0.3% of projections based on ECO for fiscal years 2011 and 2012 respectively.

For reference, the Planning Board used the following assumptions while developing its economic forecast dated April 2009 over the forecast period:

The U.S. Economy

1. Contraction of the U.S. economy of -1.4% in 2009 and a marginal growth rate of 0.5% in 2010.
2. The average price of petroleum in fiscal year 2009 was $65.33 per barrel and $47.25 per barrel in 2010.
3. A reduction of 43.3% and 14.4% in interest rates for fiscal years 2009 and 2010 respectively.

The Puerto Rico Economy

An additional $385 million in Federal transfers for 2010.

CONSUMPTION OF ELECTRICITY

Over the twenty years from the mid-1980's through 2006, the annualized rate of growth in the consumption of electricity in Puerto Rico was generally greater than that of the U.S. mainland. Interruptions in this pattern were principally caused by major weather events. The event with the greatest impact occurred in 1998 when Hurricane Georges devastated the island, causing severe damage to the Authority's system and a dramatic, short-term curtailment in power sales. By fiscal year 2000, however, the annual growth rate in the Authority's energy sales rebounded back to a robust 6.8%. The growth rates for energy sales in fiscal years 2001, 2002, and 2003, were moderate at 3.2%, 2.2% and 4.0% respectively. For fiscal years 2004 through 2007 the decline in the annualized growth rate for energy sales continued with marginal growth rates of 1.9%, 1.2%, 0.6% and 0.3%, respectively. For fiscal years 2008 and 2009 energy sales declined sharply resulting with negative growth rates of 5.2% and 5.5%, respectively

The five-year power sales projection in the Current Forecast shows continued annual declines of 3.5%, 1.1%, 0.4%, for fiscal years 2010 through 2012, respectively and incremental positive growth of 0.2% and 0.7% in fiscal years 2013 and 2014, respectively. As shown on the comparative chart below, Electric Retail Sales-All Sectors US & PR, the rate of growth in electric sales have gradually decreased over the past five years in Puerto Rico as it has on the U.S. mainland. Looking forward, energy sales in Puerto Rico are projected to rebound and reach positive growth in fiscal years 2013 and 2014. U.S. energy sales dropped 5.2% in calendar year 2008, are forecast to contract for a second consecutive year in 2009

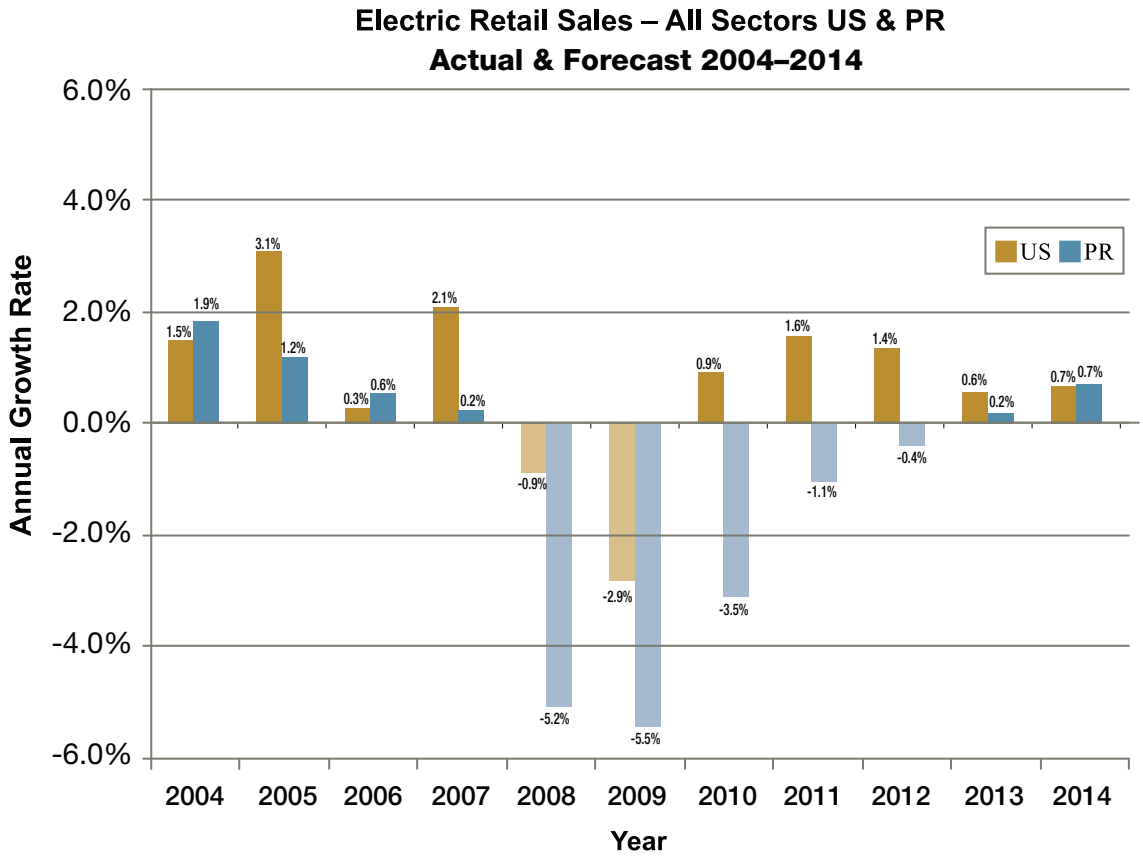
and then grow marginally in the calendar years 2011-2014. The data for the U.S. are derived from two EIA sources. The first EIA source is the Short-Term Energy Outlook, which is published on a monthly basis and is therefore current, was referenced for the historic data and the forecast for the calendar years 2009 and 2010. The EIA's Annual Energy Outlook was the source for the forecast data in calendar years 2010 through 2014. Data for 2010 were taken from the August 2009 Short-Term Energy Outlook, which reflected scaled back energy sales projections in comparison to the projections for 2011 and later, which were taken from the Annual Energy Outlook prepared in December 2008.

DEMAND AND ENERGY FORECAST

GENERATION FORECAST

The total net generation for fiscal year 2009, including purchased power and hydro-power, was 21,763 GWh, which was a 5.4% decline from the amount generated in the previous year. Over the five-year period from fiscal year 2004 through 2009, the compound annual growth rate (CAGR) in net generation was negative 1.1%. The Current Forecast of electric generation over the next five fiscal years, through 2014, has a CAGR of negative 0.8%. The long-term generation forecast for the next ten years through fiscal year 2024 project small but steady annual increases with a CAGR of 0.7% in that ten year period.

The Current Forecast develops generation data using the gross generation of the Authority's plants plus the amount of purchased power, which is the net output of the two cogenerators. As discussed above the generation projection in the Current Forecast was based on actual generation data through February 2009, preliminary generation data for March, and a projection for the balance of the fiscal year. The annual



generation for fiscal year 2009 in the Current Forecast predicted a decline of 5.4% compared to 2008, which closely matched the observed decline in net generation for the same period. The annual generation for the forecast period was determined utilizing a system efficiency that was the System's 12-month system average to February 2009, based on the sales and generation data methodology in the Current Forecast.

PEAK DEMAND FORECAST

Consistent with the Authority's conservative approach to expansion of generation capacity the Current Forecast used the projections of IAU-GI for the development of the peak demand forecast because it was the most expansive of the three economic consultants forecasts.

For the third consecutive year the System did not reach a new peak demand. The current historic system peak of 3,685 MW was established in September 2005, in fiscal year 2006. From fiscal years 2004 to 2009 the five-year CAGR in actual peak demand contracted by 0.9%. The peak demand for fiscal year 2009 was 3,351 MW which was 5.5% less that the peak demand reached during fiscal year 2008 and 9.1% less than the historic system peak demand.

The Current Forecast utilized a system load factor of 78.19% to project peak demand for the duration of the generation forecast to fiscal year 2030. The system load factor is the ratio of the average demand in kilowatts supplied during a designated period, in this case the 12 months through February 2009, to the peak or maximum demand also measured in kilowatts.

The most expansive model in the Current Forecast predicts that the 3,685 MW peak demand established during fiscal year 2006 will not be exceeded over the twenty-one year duration of the forecast. The forecast peak demand projects a 0.6% contraction in the CAGR during the five-year period from fiscal year 2009 through 2014 and 0.1% over the ten years from fiscal year 2009 through 2019. For comparison, the 2008 peak demand forecast showed a 0.9% CAGR for the five-year period through fiscal year 2013 and 0.8% for the ten-year period through fiscal year 2018.

Since 1993 the Authority has included explicit recognition of the potential effects of its DSM & EC programs in its peak demand forecasts. These programs are discussed below.

The *Peak Demand Forecast Comparison* graph below shows the degree in which the peak demand forecast has changed over the last several years.

DEMAND-SIDE MANAGEMENT AND ENERGY CONSERVATION PROGRAMS

Electric utilities offer programs to encourage clients to modify their levels and patterns of electric consumption. The implementation of such programs, known collectively as Demand-Side Management & Energy Conservation (DSM & EC), achieve two objectives; energy efficiency and load management. DSM initiatives such as load management programs are designed to achieve load shifting from peak hours to non-peak periods. Energy efficiency measures reduce the energy consumption of end-use devices and systems by promoting high-efficiency equipment and energy-efficient building design. Successful DSM & EC programs promote energy efficiency and achieve cost-effectiveness for utilities and clients thereby delaying the need for new capacity. DSM & EC programs help to conserve fossil fuel resources, reduce air pollution, and lower a utility's need for capital and its carrying costs.

As part of its Load Management Program the Authority promotes: Time-of-Use (TOU) rates to improve or smooth out its load curve; the purchase of energy-efficient motors and air conditioners; and the use of more efficient lighting. TOU rates offer economic incentives to Industrial and Commercial clients who modify their patterns of energy consumption, i.e., adding load to off peak hours and reducing load during peak hours. (For more information on TOU rates see the *Rates* section.) The Authority, with a limited staff, also offers clients advice on power factor improvement that benefits both the client and the Authority.

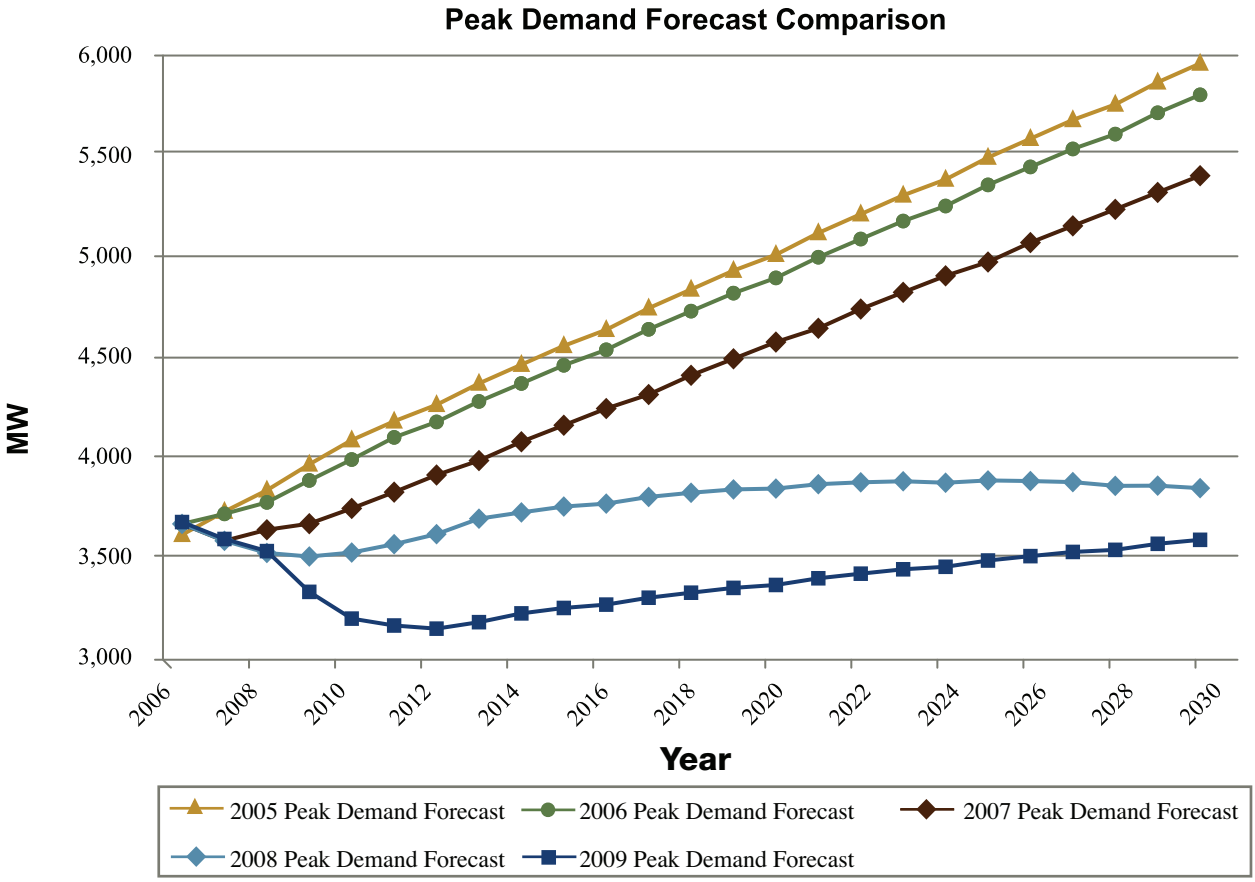
As part of its energy conservation program, the Commonwealth government promoted in September 2008 an energy efficiency program that offered a $5 discount coupon for the purchase of four or more compact fluorescent light bulbs. The coupons were inserted into approximately 1.3 million residential electric bills during the monthly billing cycle starting on September 8, 2008 and were valid until the end of the calendar year. The Department of Consumer Affairs froze the price of the light bulbs as of August 15, 2008. The coupons could be redeemed at many authorized retailers through out the island. The estimated cost of this program was $6.6 million.

The Authority, as it has for the past several years, projects that the savings from its DSM & EC program will lower peak demand by 1 MW per year. Its load reduction program might be even greater if the

optional energy management system (EMS) component were added to the automated meter reading system that is being installed throughout the system. Employing the EMS would allow the Authority to control clients' equipment, such as air conditioners, for periods when load management is desirable. The Authority continues to analyze the potential for load control among its small commercial clients.

CAPACITY PLANNING

The Authority periodically updates its Capacity Expansion Plan (CEP) as part of its efforts to ensure its ability to meet expected long term electric load growth, to provide reliable, cost-effective electric service to its clients, and to reduce its dependence on fuel oil. The CEP is updated using system-planning software that is widely accepted throughout the electric utility industry. The software employs multiple factors to determine the least cost system operation and expansion over the forecast period. Amongst other inputs, the computer simulation accounts for the unique cost and operational attributes of each existing and potential new production unit in the System. In addition, the model reflects that the Authority has no neighboring utilities with which to interconnect, that each of its large units supply a relatively high percent of the system load and that its load is fairly constant throughout the year. These last three characteristics significantly increase the reserve generating capacity



that the Authority must maintain in order to be able to provide reliable service to its clients.

The Consulting Engineers regularly reviews the Authority's capacity planning and believes that the Authority's Capacity Expansion Plan discussed in this section provides a reasonable basis for its capacity planning at this time.

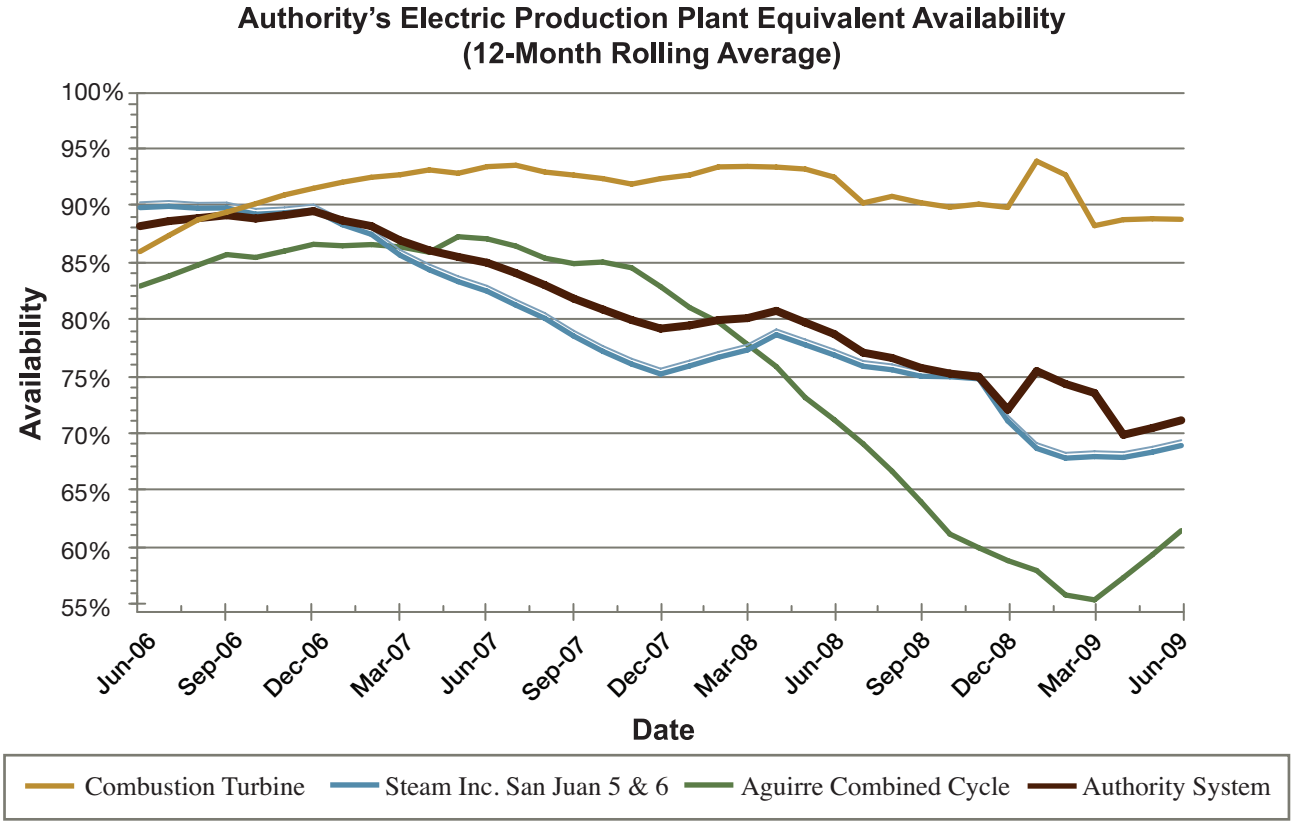
OVERVIEW

AVAILABILITY

The Authority has directed considerable resources over almost two decades towards improving the availability of its electric production plant. With these significant capital expenditures, the Authority has been able to extend the life of its generating facilities, reduce the need for extended scheduled outages, and lower the frequency of forced outages, thereby increasing the percentage of time its generating units are available for service. During the last decade the Authority's total System annual production plant availability increased from being consistently in the range of 80% up to 2003, to more than 84% by the end of calendar year 2005, and as high as 88% in December 2006.

On December 29 and 30, 2006, the Palo Seco Steam Plant was forced out of service as the result of two separate fires. The extended loss of the 602 MW steam plant from the island's load center severely tested electric production plant reserve capacity and the transmission system ability to move large quantities of power from the large generating units in the south to the load centers on the northern side of the island. Total system availability dropped from 88% just prior to the fires to 71% at the close of the fiscal year 2009. Restoration of the first two units at Palo Seco placed 170 MW back into the System; Unit 2 returned to service in November 2007 and Unit 1 returned in April 2008. The two larger 216 MW units required extensive overhaul with Unit 4 returning to service in March 2009, and Unit 3 scheduled for return in the first quarter of fiscal year 2010. The Authority anticipates recovery to previously demonstrated high levels of availability by fiscal year 2013, following completion of the scheduled major overhauls of certain larger steam units. As discussed in the *System's Operations* section some of these major overhauls were deferred pending restoration of the Palo Seco Steam Plant units.

The Authority's overall production plant equivalent availability for the three-year period ending June 30, 2009 is shown with performance by the three major kinds of generation—steam, combustion turbine, and combined cycle.



NEW CAPACITY

During fiscal year 2009 the Authority accepted for commercial operation two combined cycle units at the San Juan Steam Plant and eight combustion turbines at the Mayagüez facility.

The San Juan project, San Juan Units 5 & 6 went commercial in October 2008, and adds 464 MW of efficient combined-cycle capacity to the Authority's System. The addition is comprised of two combined-cycle units each consisting of one combustion-turbine rated at 165 MW with a heat recovery steam generator (HRSG) feeding a single 67 MW steam turbine-generator. The new combined cycle units are currently the most efficient of the Authority's production units.

The Mayagüez combustion turbine project replaced four older less efficient 21 MW combustion turbines with eight 27.5 MW dual fuel aero-derivative combustion turbines making four 55 MW units; each unit is comprised of two combustion turbines driving one generator. The first two units started operation in the third quarter of fiscal year 2009, operation of the last two units was accepted in the fourth quarter of the past fiscal year. The replacement combustion turbines incorporate newer technology that significantly improves the overall efficiency of the facility and adds 136 MW of new capacity.

Both the San Juan and Mayagüez units will initially operate on distillate fuel, with the provision for switching to natural gas when gas becomes available at the facility.

PURCHASED POWER

In parallel with the internal program to improve production plant performance, the Authority entered into long-term purchased power agreements with the owners of two privately owned and operated cogeneration facilities. These new plants were selected to aid the Authority in providing for electric load growth, reduce the island's dependence on fuel oil, and continue to improve the System reliability.

In accordance with a 22-year power purchase agreement (PPA) that commenced on March 21, 2000, the Authority began purchasing 507 MW of power produced by EcoEléctrica, L.P.'s gas-fired combined-cycle cogeneration facility. The PPA outlines capacity and energy charges to be paid by the Authority based on the performance and electrical output of the facility. A principal condition of the agreement is a progressive reduction in the monthly capacity charge, paid by the Authority, subject to the facility meeting a minimum 93% availability on a 12-month rolling average. EcoEléctrica's target availability for fiscal year 2009 was reduced to 90% because of scheduled maintenance work; the actual availability was 89.6% for the period. The target availability during fiscal year 2010 will return to 93%.

The Authority has also entered into an agreement with AES-PR to purchase 454 MW of power from its coal-fired steam-electric plant. The plant, which consists of two identical fluidized-bed boilers and two steam turbines, uses clean-burning coal technology. The facility commenced commercial operation on November 29, 2002. The 25-year PPA with AES-PR is similar to EcoEléctrica, L.P.'s. The minimum guaranteed availability for AES-PR is 90%, slightly lower than EcoEléctrica, L.P.'s, but typical of coal-fired electric generating plants. Actual availability for the 12 months ended June 30, 2009 was 88.2%.

These PPA's have allowed the Authority to reduce its dependency on fuel oil, mitigate the economic risk of its electric system operation, and to schedule the retirement of some of its older, less efficient generating units. For further discussion on EcoEléctrica and AES-PR, refer to the *Cogenerators* in the *System's Operations* section.

Prior to the Authority purchasing power from the cogenerators, nearly 99% of the energy sold by the Authority was produced by its oil-fired units. During the current period of depressed energy sales, it is estimated that up to 37% of the Authority's annual energy sales could be derived from fuels other than oil, when both the EcoEléctrica, L.P. and AES-PR plants are operating at base load. In fiscal year 2009 actual cogenerator generation was 30.6% of the system total. Subject to dispatch and actual availability, the combined generation of EcoEléctrica, L.P. and AES-PR is forecasted to be 31.8% of the total System generation in fiscal year 2010.

Other benefits of the cogeneration contracts include fixing the cost of fuel used to generate electricity for each year of the contract at the beginning of such year. Annually, the fuel portion of the energy charge per kWh is set based on actual fuel-related energy charges for the preceding year, adjusted using inflation and other indices. The fixed nature of the fuel cost reduces short-term variations in the Authority's energy costs by bringing purchased power costs out of step with price changes in other components of the Authority's fuel mix. The fixed fuel costs also affords the Authority the opportunity to better dispatch its electric production plant.

FUTURE CAPACITY PLANNING

The Authority's current capacity expansion plan is based on the Authority's most recent Current Forecast dated April 2009. As discussed in the *Demand and Energy Forecast* section, the Current Forecast shows declining peak demand through fiscal year 2013 with only modest annual increases afterwards. The previous system peak of 3,685 MW, established in fiscal year 2006, is not currently forecasted be exceeded until beyond the horizon of the Authority's capacity planning.

The reduction in forecasted peak demand allows the Authority to focus on reducing and stabilizing future electric power costs by decreasing its dependence on oil while improving the overall efficiency of its electric production plant. The first step in this process is to expand the use of natural gas for electric generation by utilizing it in modern efficient generating units. The price structure of LNG also tends to provide stable electric energy prices in comparison to oil. The Authority plans to initially utilize the excess storage capacity at the existing LNG facility located in Guayanilla at the EcoEléctrica cogeneration plant.

The first project to use the available gas at EcoEléctrica was intended to be the two existing 296 MW combined cycle units at the Aguirre plant, which were converted to dual fuel capability. The pipeline project from Guayanilla to Aguirre was canceled in April 2009, however, in response to community opposition to the pipeline.

The Authority is currently evaluating the utilization of the surplus gas storage at EcoEléctrica for a new combined cycle facility to be located at the Costa Sur Steam Plant. The combination of modern combined cycle efficiencies and the reduction in equivalent gas pricing over distillate could provide electric energy savings of more than 35% over any of the Authority's existing oil-fired generating units based on current forecasts of fuel pricing.

The Authority's strategic plan is to expand the use of gas for electric generation across the island. As gas becomes available, the next candidate for gas firing will be the San Juan Units 5 & 6, which have dual firing capability and are currently the most efficient Authority owned generating units.

To further reduce its dependence on oil, the Authority is studying the construction of a new coal-fired plant at a former refinery in Guayama, on the island's southeast coast. The Authority is also studying the possible conversion of one or more of its steam generating units to coal firing. The conversion would require the construction of a new boiler to maintain steam cycle capacity and efficiency.

As stated above, the gas and coal fueled projects described are not required for load growth, and as such, are not presently included in the Capacity Expansion Plan while the Authority considers the economics of ownership and long term power purchase agreements.

The first six years of the current CEP are excerpted in the Capacity Expansion Plan table. Details of existing generating capacity of the System and the anticipated changes through fiscal year 2014 are shown in *Appendix VIII, System Capability.*

ALTERNATIVE ENERGY SOURCES

The Authority's policy is to review all valid proposals submitted by developers for power projects on the island. The basic economic criterion used to evaluate these proposals is that the cost of the power must be at or below the Authority's avoided cost for that power, which is the cost the Authority would incur if it were to build and operate the new capacity itself.

CAPACITY EXPANSION PLAN
(In MW)

Fiscal Year Ending	Peak Demand[1]	DSM Savings	Peak Demand Less DSM	System Capacity End of Year	Installed New Capacity	Retirements	Reserve Margin	Reserve Margin%
2009	3,351	0	3,351	5,864	684	84	2,513	75%
2010	3,224	1	3,223	5,864	0	0	2,641	82%
2011	3,192	2	3,190	5,864	0	0	2,674	84%
2012	3,178	3	3,175	5,864	0	0	2,689	85%
2013	3,210	4	3,206	5,864	0	0	2,573	80%
2014	3,253	5	3,248	5,779	0	85	2,531	78%

[1] 2009 Actual; 2010-2014 Based on IAU-GI projections in the Current Forecast dated April 2009.

At the end of fiscal year 2009 there were no firm alternative energy sources in the Authority's CEP because of uncertain project viability and timing.

To promote the use of renewable resources for the production of electric energy and further expand its energy diversification, the Authority created two subsidiaries to facilitate its participation in alternative power projects. The first wholly owned subsidiary is PREPA Oil & Gas, which was established to provide a mechanism for the Authority to participate in gas infrastructure projects or arranging fuel supplies for private power generators. The other new subsidiary is PREPA Renewables. This subsidiary was formed for the Authority to assist in funding renewable energy projects or to establish a joint venture with developers of renewable energy projects. Both subsidiaries currently hold no assets.

The Authority has entered into Power Purchase Agreements (PPA) with developers to purchase electric energy from three different wind energy projects and a waste-to-energy project. The wind projects, while not yet permitted, are 39 MW, 40 MW and 50 MW each. The largest 50 MW farm is to be located in Guayanilla on the southern side of the island.

The PPA with the waste-to-energy project is for 50 MW. This project is still in the permitting stage. Discussions related to a second waste-to-energy project continued during the past fiscal year, with no conclusion. While these facilities could help solve the waste disposal problems on the island, these projects have historically been uneconomic on the island and none are presently in operation.

To encourage more efficient and renewable on-site generation technologies such as photovoltaic panels, the Commonwealth legislature enacted the Economic Incentives Act in 2008 that sets out the basis under which the Authority would buy the excess power self-generated by a client. The scope of the Economic Incentives Act is discussed the *Financial* section. At this time the energy from distributed generation sources are not included in the CEP.

FUEL MIX

For information on the types of fuel used in the Authority's various generating units see the *Fuels* section under *System's Operations*.

The Authority purchases all its fuel oil under one-year contracts that include an option for a second year. These contracts are structured to reflect physical clearing prices, and avoid speculation in the market. In addition, the pricing structures of the two cogenerators are based in part on annual indices to provide stable pricing for purchased power. These strategies, however, do not isolate the Authority from changes in energy costs that have been occurring over the last few years; all production related fuel expenses are currently recovered through the fuel component of the adjustment charge.

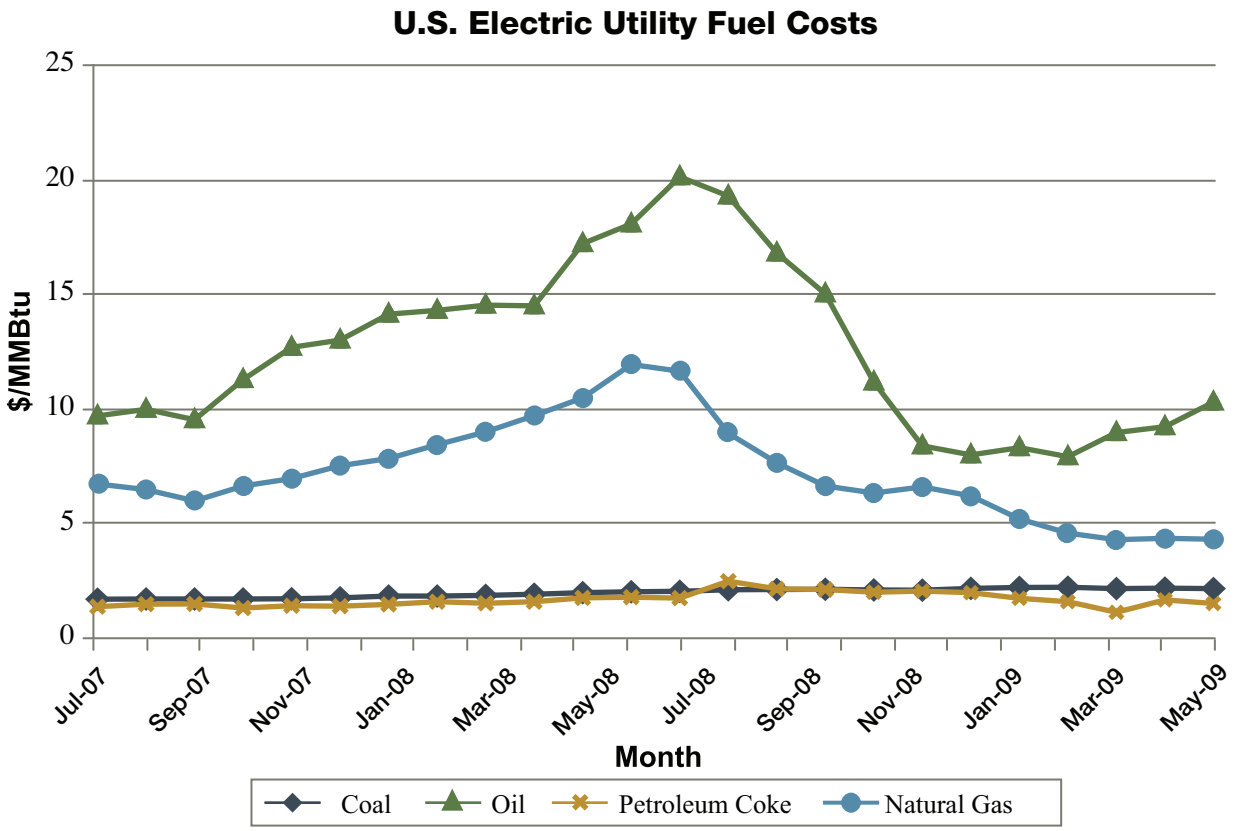
The total projected use of each type of fuel is based on generation required to meet the demand forecasts developed in the Current Forecast. The Authority utilizes an economic dispatch simulation of all generating sources in the System to determine the lowest cost generation plan. The dispatch simulation takes into account the heat rate, operational characteristics and fuel costs specifically for each plant. As discussed in the *Current Forecast* section, this information was developed for the remaining months of fiscal year 2009 and summarized annually for the five-year intermediate-term forecast. The actual annual results of generation, fuel use and costs for fiscal year 2009 and those forecasted over the five-year period are presented in *Appendix IV, Annual Generation, Fuel Consumption, and Fuel Costs for Thermal Stations.*

Although the data in the chart below is based on mainland facilities, the chart shows the volatility from July 2007 to June 2009 in the price of most fossil fuels used at electric generating plants as reported to the Energy Information Administration's (EIA), the reporting arm for the Department of Energy. It should be noted that the natural gas data in the chart reflect pipeline gas, while the only natural gas available in Puerto Rico is liquefied natural gas (LNG), which has a different pricing basis.

FUEL OIL

The Authority's average cost of fuel oil, including transportation and fuel-handling costs in fiscal year 2009 was $76.23 per barrel. The total costs of fuel for fiscal year 2009 and the five-year forecast period are shown in *Appendix III, Detail of Operating and Maintenance Expenses.*

The Authority's projected cost of fuel per barrel including handling charges for fiscal year 2010 is $65.99 and is forecasted to be $80.38, $94.04, $100.22, and $104.40 in 2011 through 2014, respectively. As discussed in the *Annual Budget* section, these fuel costs were utilized in the Authority's amended Annual Budget that was developed in January 2010. The forecasted prices of fuel are based on EIA indices for the types of fuel oil the Authority burns adjusted for the Authority's location and inci-



dental charges. The composite barrel cost is based specifically on the mix the Authority has forecast to be utilized in the generating units. For its short-term projection the Authority used the EIA's *Short-term Energy Outlook* dated August 2009. For its intermediate-term projections the EIA's *Preliminary Annual Energy Outlook 2009* dated December 2008 was used.

These projected fuel costs were used to develop the annual costs of fuel and the fuel adjustment revenues in the Authority's Current Forecast (See *Appendix I, Intermediate-Term Financial Planning Forecast*).

The Authority's oil fired units generated 69.8% of the System total energy in fiscal year 2009. Its total fuel oil storage capacity is 4.7 million barrels, including rented storage. This maximum capacity would be sufficient for the Authority to operate more than 50 days; however, the Authority typically maintains a 30 day inventory of fuel oil. It is worthwhile to note that the Authority has never had to curtail electric service from fuel oil shortages or from problems delivering fuel to its generating facilities.

NATURAL GAS AND COAL

Natural Gas

In March 2000 the Authority entered into a 22-year contract with EcoEléctrica, L.P. to purchase all the power produced by the first natural gas fired facility on the island. In fiscal year 2009, EcoEléctrica, L.P. represented 8.6% of the System's capacity and provided 15.1% of the Authority's dispatchable energy. For fiscal year 2010 the energy provided to the Authority's system is forecast to be 15.8% of the total.

As discussed above, part of the Authority's long-term fuel strategy has been to increase the use of natural gas in new and selected existing units. While the excess liquefied natural gas (LNG) storage capacity at the EcoEléctrica facility could be sufficient to supply a nominal 500 MW gas-fired combined cycle plant; any subsequent increased utilization of gas will require new LNG infrastructure for handling, storage, and gasification.

To establish the forecast cost of LNG, exclusive of EcoEléctrica, the Authority uses the EIA's projected price for imported LNG and applies an adjustment factor for transportation costs and re-gasification costs in Puerto Rico.

Coal Fueled AES-PR

The AES-PR plant began commercial operation in November 2002. The plant uses fluidized bed boilers, which are considered a clean coal-burning technology The Authority has entered into a 25-year PPA to purchase all the power produced by the facility. Although AES-PR comprises 7.7% of the System's capacity, this co-generator also provided 15.5% of the Authority's dispatchable energy during fiscal year 2009. It is anticipated that the plant will provide 16% of the system's total generation in fiscal year 2010.

To establish the forecast cost of energy from the AES-PR coal plant, AES provides the Authority with the annual forecast costs from its supplier.

ENERGY SALES FORECAST

The Authority's annual Current Forecast contains detailed projections of short-to-intermediate-term sales and revenues. The methodology and results of the Current Forecast are discussed in the *Current Forecast* section above. As is usually the case, this year three economic consultant's projections of the economy of Puerto Rico were examined in the Current Forecast. The consultants forecast two key macroeconomic indicators Gross Domestic Product and Gross National Product, which are used with other variables to project the intermediate-term electric sales and revenues.

To account for the uncertainty inherent in economic forecasting the Authority generally chooses the least optimistic economic consultant's projections over the intermediate five-year period for its financial forecast. In this year's Current Forecast an exception was made to utilize the least expansive for the first two years of the forecast period, as discussed in the Current Forecast section.

SHORT-TO-INTERMEDIATE TERM ENERGY SALES FORECAST

As discussed in the *Current Forecast* section, the growth rate in the Authority's total kWh sales has been steadily slowing over the last several years and actually contracted over the past two years. The actual total kWh sales in fiscal year 2009 decreased 5.5% from the previous year and the three largest sectors experienced a decline as they did in fiscal year 2008 when total kWh sales experienced a decrease of 5.2%. The projection from last year's Current Forecast was a 1.3% decrease in energy sales for fiscal year 2009.

As shown in the table below, total sales for fiscal year 2010 are projected to decrease by 3.5%. The annual decrease in total energy sales is projected to continue to fiscal year 2012 and increase marginally during the final two years of the five-year forecast. The Current Forecast projects annual kWh sales for fiscal years 2011 through 2014 to be -1.1%, -0.4%, 0.2%, and 0.7%, respectively.

Last year's Current Forecast projected that energy sales would decrease at a CAGR of 0.3% over the five-year period ending in fiscal year 2013. This year's Current Forecast for fiscal years 2009 through 2014 projects an annual decrease of 0.8% over the five-year period. For comparative purposes the EIA projects that the CAGR for U.S. mainland electric sales for the five calendar years ending in 2014 will be 1.6%.

The projected energy sales through fiscal year 2014, taken from the Authority's Current Forecast, are summarized in *Appendix I, Intermediate-Term Financial Planning Forecast*.

The table below, Short-term Energy Sales Forecast, shows actual kilowatt-hour sales and percent change from the prior year by major client classifications for fiscal years 2008 and 2009. It also shows the projected kilowatt-hour sales and percent change from the prior year by major client classifications for fiscal years 2009 and 2010 taken from the Authority's Current Forecast.

SHORT-TERM ENERGY SALES FORECAST
(GWh)

	FY 2008	FY 2009		FY 2010
	Actual[1]	4/09 Estimate	Actual[1]	4/09 Forecast[2]
Residential Sales	6,757.2	6,346.5	6,367.6	6,038.3
Annual Increase (Decrease)	*(6.7%)*	*(6.1%)*	*(5.8%)*	*(4.9%)*
Commercial Sales	8,743.5	8,511.5	8,498.1	8,340.9
Annual Increase (Decrease)	*(1.9%)*	*(2.7%)*	*(2.8%)*	*(2.0%)*
Industrial Sales	3,742.5	3,354.7	3,288.6	3,188.3
Annual Increase (Decrease)	*(9.5%)*	*(10.4%)*	*(12.1%)*	*(5.0%)*
Other Sales[3]	358.3	361.5	361.5	361.5
Annual Increase (Decrease)	*(6.2%)*	*0.9%*	*0.9%*	*0.0%*
Total Sales	19,601.6	18,574.3	18,515.8	17,929.0
Annual Increase (Decrease)	(5.2%)	(5.2%)	(5.5%)	(3.5%)

1. As reported in the Authority's Preliminary June 2009 Governing Board Report.
2. Percentage is calculated on forecast sales for fiscal year 2009
3. Other Sales are comprised of Agricultural, Other Public Authorities, and Public Lighting.

The kWh sales statistics for the U.S. cited in the following discussions are taken from EIA reports: *Annual Energy Outlook 2009 with Projections to 2030* dated March 2009, and *Short-term Energy Outlook—August 2009*. The U.S. 2008 calendar year energy sales are preliminary and 2009 are estimated.

RESIDENTIAL KWH SALES

Fiscal year 2009 marks the forth consecutive year that there has been a decline in residential energy sales. During fiscal year 2009 residential energy sales were 6,367.6 GWh or 5.8% less than fiscal year 2008, which in turn had experienced residential energy sales that were 6.7% below the previous year. The continuing economic recession and the increased cost of living has played a large part in the decline in energy sales to this sector. In the Authority's Current Forecast, residential kWh sales for fiscal year 2010 are estimated to decrease by 4.9%.

Actual residential kWh sales for the five-year period ended June 30, 2009 decreased at a CAGR of 2.8%. The Current Forecast projects the residential sector consumption to decrease at a CAGR of 2.5% through fiscal year 2014.

The average number of residential clients the Authority served during fiscal year 2009 was 1,324,752—an increase of 0.8% from the previous year. In the past five-year period the number of residential clients increased at a CAGR of 0.6%. For fiscal year 2010 the number of residential customers is projected to increase by 0.2% and the forecasted CAGR five-year period ending in 2014 in the number of residential clients is forecast to increase by 0.2%.

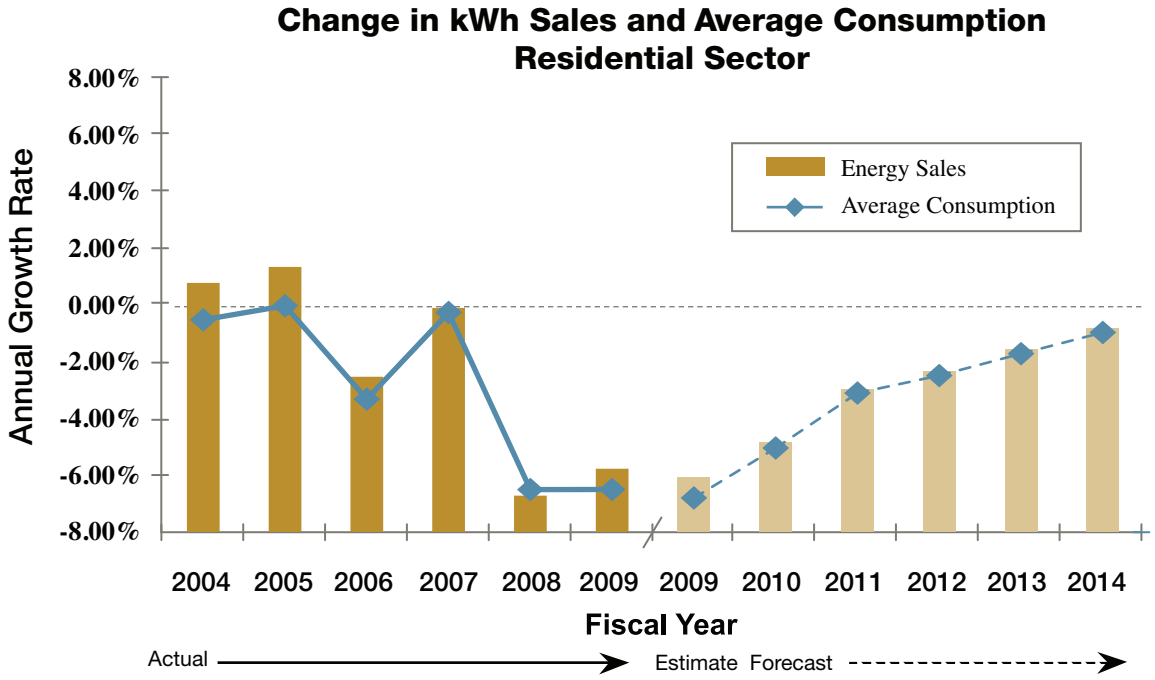
In fiscal year 2009 the average annual electric consumption per residential client was 4,806.6 kWh, which was 6.8% less than the previous fiscal year; this continued a trend of decreased consumption over the last six years. In fiscal year 2010 the average residential energy consumption is forecast to decrease by 5.0%, with a slowly improving negative trend continuing throughout the five-year period. The past five year CAGR of average residential consumption contracted by 3.4%. The future five-year CAGR in average residential consumption is forecast to be negative 2.7%.

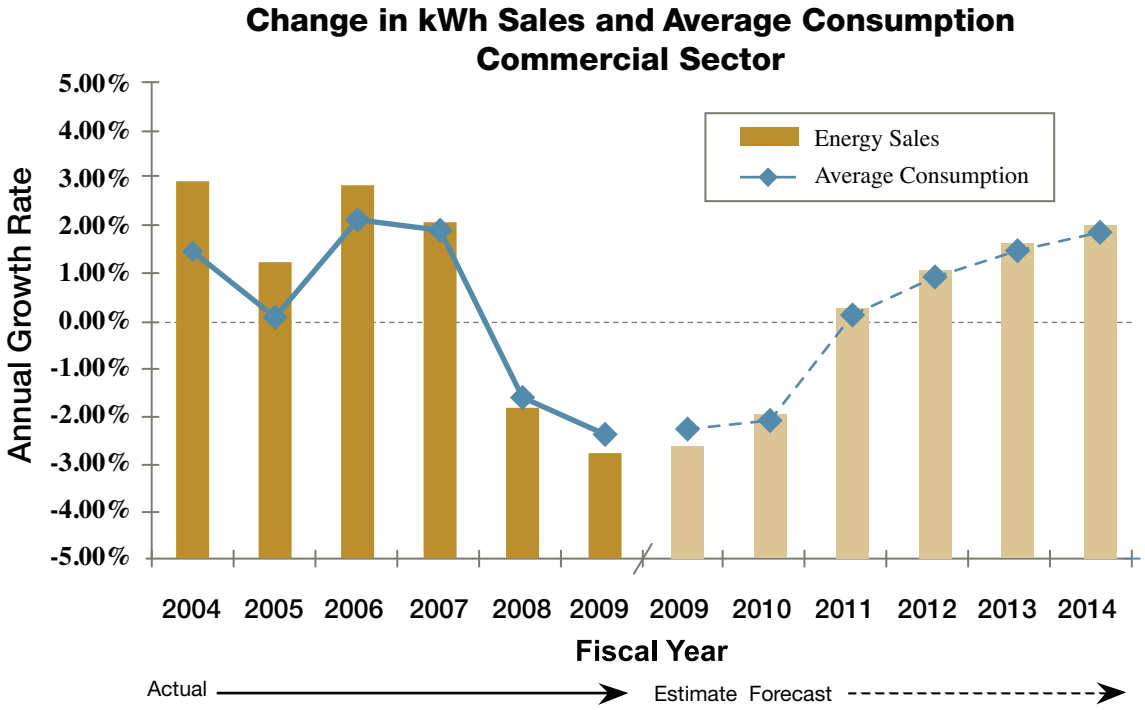
EIA data for recent performance of the U.S. electric sales are preliminary. These data show that U.S. residential energy sales decreased 1.2% in calendar year 2008 and are estimated to increase by 0.3% in calendar year 2009. The preliminary five-year CAGR in U.S. residential kWh sales for calendar years 2004 through 2009 is 1.3%. The projected five-year compound growth rate in U.S. residential kWh sales for calendar years 2009 through 2014 is 0.3%.

According to EIA statistics, the average electric consumption of the Authority's residential clients is approximately 46% of the average electric consumption of residential clients of the U.S. South Atlantic Census Division.

COMMERCIAL KWH SALES

Commercial kWh sales declined for the second consecutive year in fiscal year 2009, with a decrease of 2.8% from the previous fiscal year. In fiscal year 2008 commercial kWh sales decreased 1.9% from those of the previous fiscal year. The Current Forecast projects that commercial power sales will decrease by 2.0% in fiscal year 2010.





The five-year CAGR of commercial sales from 2004 through 2009 was 0.2%, however, the Current Forecast projects a future five-year CAGR from 2009 through 2014 of 0.5%. This year's Current Forecast contrasts with last year's forecast which projected a 0.1% contraction in the CAGR in commercial energy sales over the five-year period ending 2013.

The average number of commercial clients during fiscal year 2009 was 129,492, a decrease of 0.4% from the previous fiscal year. The CAGR in the commercial client base for the five years through fiscal year 2009 was 0.3%. In fiscal year 2010 the average number of commercial clients is projected to increase by 0.1% and uniformly continue that rate of expansion for the future five years through 2014.

The average annual consumption per commercial client during fiscal year 2009 was 65,627 kWh for a decrease of 2.4% from the previous year. The

Authority's actual five-year CAGR in consumption per commercial client through the end of fiscal year 2009 was negligible. For fiscal year 2010 the average kWh consumption per commercial client is projected to decrease by 2.1%. The Current Forecast projects a CAGR of 0.4% in electric consumption per commercial client over the next five fiscal years.

Based on preliminary EIA data, U.S. commercial kWh sales grew 0.6% in calendar year 2008 and are estimated to decrease by 1.1% in calendar year 2009. The preliminary five-year CAGR in U.S. commercial kWh sales for calendar years 2004 through 2009 is 1.7%. The projected five-year CAGR in U.S. commercial kWh sales for calendar years 2009 through 2014 is 2.1%.

According to EIA statistics, the average kWh consumption of the Authority's commercial clients is approximately 74% of commercial clients of the South Atlantic Census Division of the U.S.

INDUSTRIAL KWH SALES

Industrial kWh sales for the fiscal year 2009 decreased 12.1% compared to the previous year during which industrial kWh sales decreased 9.5%. Actual industrial kWh sales for the five-year period ending in fiscal year 2009 decreased at a CAGR of 4.2%.

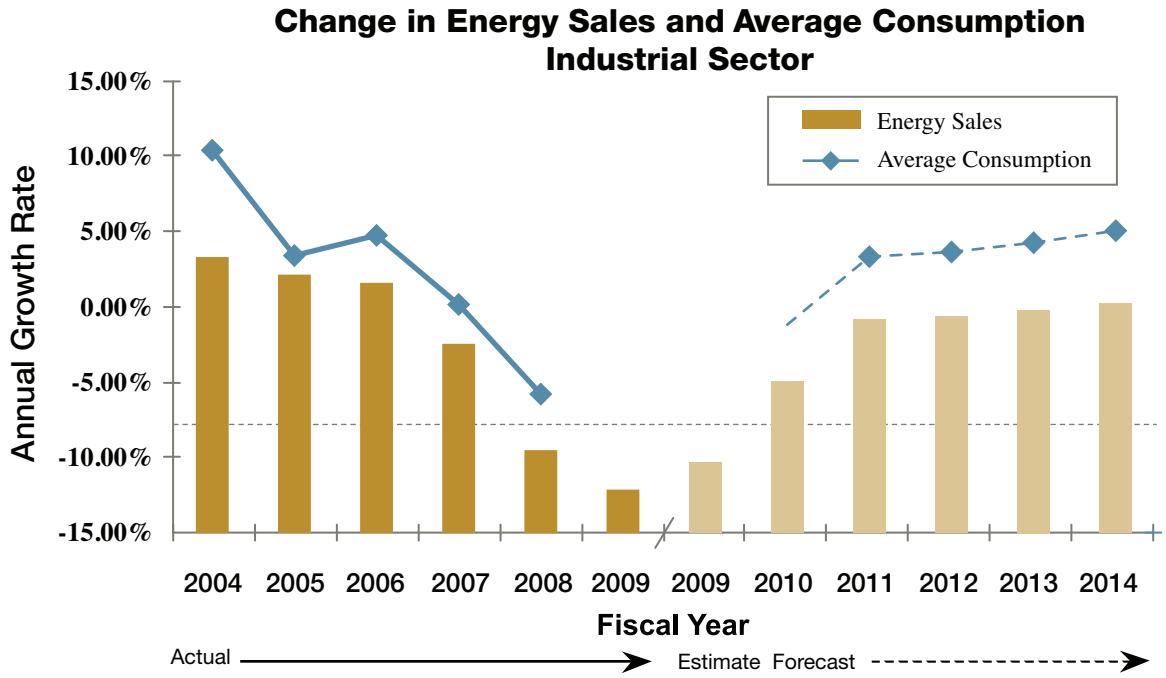
The Current Forecast projects that in fiscal year 2010 industrial energy sales will decrease by 5.0% followed by marginal annual contractions of less than 1.0% to 2013 and a 0.2% increase in 2014. This sector is forecasted to contract at a CAGR of 1.3% for the five-year period through fiscal year 2014.

During fiscal year 2009 the Authority reclassified 612 government industrial clients from the industrial General Service at Secondary Voltage tariff to the corresponding commercial tariff, to lower these clients' rates. The transfer of these clients from the industrial to commercial base reduced the size of the industrial sector by more than 40%. At the end of fiscal year 2009 the Authority served 898 industrial clients. The average annual consumption of those clients at the end of fiscal 2009 was 3,662.1 MWh. The Current Forecast projects the number of industrial clients to decrease by approximately 34 clients per year over the next five years. The average consumption per Industrial client is omitted form the graph below for fiscal years 2009 and 2010 because of the reclassification.

The CAGR for the future five-year period ending in 2014 in energy use per client is projected at 2.9%.

Preliminary EIA data show total industrial U.S. kWh sales decreased 2.8% in calendar year 2008 and are projected to decrease by 10.3% in calendar year 2009. The preliminary five-year CAGR in U.S. industrial kWh sales for calendar years 2004 through 2009 is negative 2.9%. The projected CAGR in U.S. industrial kWh sales for calendar years 2009 through 2014 is 2.7%.

According to EIA statistics, the average kWh consumption of the Authority's industrial clients is approximately 100% more than those of the South Atlantic Census Division of the U.S.



OTHER CLASSES KWH SALES

The sum of the kWh sales in fiscal year 2009 to clients in the public lighting, agricultural and other public agency classes, known as the "Other" sector, represented less than 2% of the Authority's total energy sales. In 2009 the group's kWh sales were 0.9% more than for the previous year. In fiscal year 2008 the Other sector posted a decrease in kWh sales of 6.2%. The Authority's Current Forecast projects virtually no change in kWh sales to this group throughout the forecast period.

The number of clients in this group is projected to remain unchanged during the forecast period.

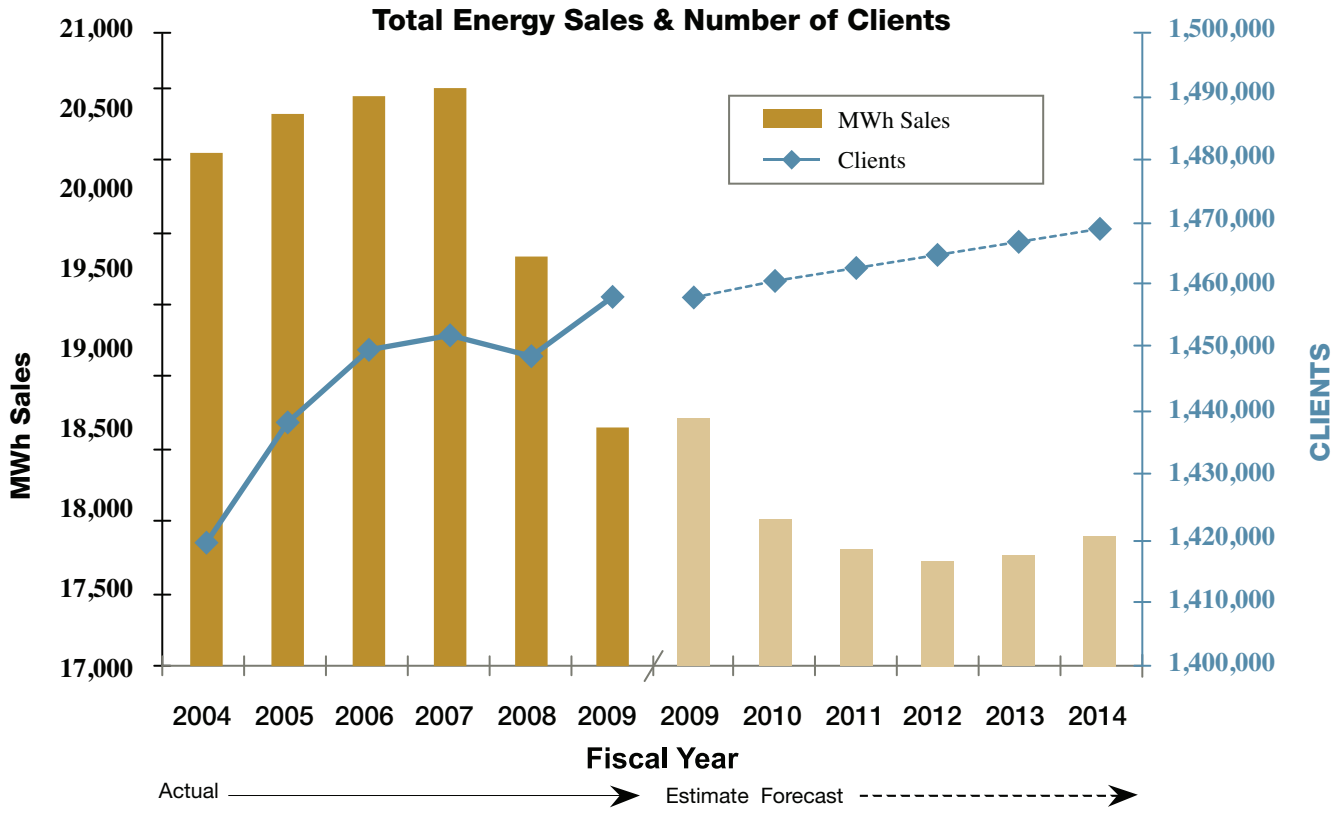
TOTAL KWH SALES

Total energy sales in fiscal year 2009 declined for the second consecutive year, with sales of 18,515.8 GWh, a decrease of 5.5% from those of the previous fiscal year. In fiscal year 2008 the total kWh sales decreased 5.2% over those of 2007. Actual total kWh sales for the five-year period ended June 30, 2009, decreased at a CAGR of 1.8%. In the Current Forecast total kWh sales are expected to decrease by 3.5% for fiscal year 2010 and to decrease at a CAGR of 0.8% per year over the five-year period ending in fiscal year 2014; this contrasts with the 0.3% growth in total kWh sales projected in last year's forecast for the five-year period ending in fiscal year 2013.

The average number of clients that the Authority served during fiscal year 2009 increased 0.7% from the previous fiscal year to 1,458,636. Over the five-year period ending in 2009 the CAGR in the number of clients was 0.5%. The total number of clients is projected to grow by 0.2% in fiscal year 2010. The total number of clients is projected to increase at a CAGR of 0.2% per year through the next five years of the forecast period ending in 2014.

The average electric consumption of the Authority's clients in fiscal year 2009 was 12,694 kWh, a decrease of 6.2% from the previous year. Over the past five-year period the CAGR was negative 2.3%. The Current Forecast projects the average consumption of the Authority's clients will continue to decrease in fiscal year 2010 by 3.7%, and the five-year CAGR is projected to decrease by 1.0% annually through fiscal year 2014.

The preliminary data for total U.S. kWh sales show a decrease of 0.9% in calendar year 2008. For calendar year 2009 total kWh sales in the U.S. are estimated to contract by 2.9%. The CAGR for the U.S. preliminary total kWh sales during the five-year period between calendar years 2004 and 2009 is 0.3% and is projected to be 1.6% for the five-year period ending in 2014.



RATES

Section 706 of the 1974 Agreement charges the Consulting Engineers to prepare each year a report setting forth their recommendations as to any necessary or advisable revisions of rates and charges.

Section 502 of the 1974 Agreement details the Authority's responsibilities with respect to rates as follows:

> *The Authority further covenants that it will at all times fix, charge and collect reasonable rates and charges for the use of the services and facilities furnished by the System and that from time to time, and as often as it shall appear necessary, it will adjust such rates and charges so that the Revenues will at all times be sufficient*

(B) after the outstanding 1947 Indenture Bonds have been paid or provision has been made for their payment and the release of the 1947 Indenture:

> *(a) to pay the Current Expenses of the System, and*
>
> *(b) to provide an amount at least equal to one hundred twenty per centum (120%) of the aggregate Principal and Interest Requirements for the next fiscal year on account of all the bonds then outstanding under this Agreement, reduced by any amount deposited to the credit of the Bond Service Account from the proceeds of bonds to pay interest to accrue thereon in such fiscal year.*

The revenues generated by the Authority's various rate schedules provide the moneys necessary for it to meet all of its obligations as detailed in the 1974 Agreement. Among its obligations are: paying the current expenses of the System; financing future growth by issuing Power Revenue Bonds; making deposits to specified funds; maintaining a minimum specified debt service ratio; and paying Contributions in Lieu of Taxes.

Typically, the client's bill consists of the appropriate base rate and an adjustment charge. The base rate encompasses current expenses, i.e. operation and maintenance (O & M) expenses (excluding the cost of fuel and purchased power), monies for funding requirements, Contributions in Lieu of Taxes associated with base rate revenue, depreciation and amortization, insurance, and debt service. The base rate has three components—a demand charge, a customer charge, and an energy charge, except for clients that receive electric service at secondary voltage. The base rate for clients served at secondary voltage is comprised of a customer charge and an energy-related charge. The adjustment charge has two components: the charge for purchased fuel and the charge for purchased power. (For a discussion of these charges see *Adjustment Charge* below.)

RATE SCHEDULES

CLASSIFICATIONS AND REVENUES

In order to serve different segments of its clientele, the Authority provides electric service in six client classifications. Ranking these classes in their order of revenue generated during fiscal year 2009, they are: Commercial, Residential, Industrial, Public Lighting, Public Authorities, and Agricultural. Three of these classifications—Commercial, Residential, and Industrial—represented 98.0% of the kilowatt-hour sales and contributed 97.2% of the Authority's revenues from the sale of electricity. The remaining three classifications—Public Lighting, Other Public Authorities, and Agricultural – collectively represented the balances of the Authority's kilowatt-hour sales and revenue from the sale of electricity.

Four rate schedules apply to the large majority of the Authority's client base. These four rate schedules are: GRS (General Residential Service), GSS (General Service at Secondary voltage), GSP (General Service at Primary voltage), and GST (General Service at Transmission voltage). These four rate schedules serve the majority of the Authority's clients because they were designed for wide applicability and they have few, if any, load characteristic requirements. To broaden their usage, the GSS, GSP, and GST rate schedules are available to both commercial and industrial clients. During fiscal year 2009 the core four rates accounted for 86.8% of the Authority's kilowatt-hour sales and 87.9% of its revenues from the sale of electricity.

The following table shows the major contribution of these four rate schedules to the Authority's electric sale and its total revenue. In each of the largest three classification there is dominant rate schedule. For example, although three rate schedules apply to the Residential classification, the GRS rate schedule serves 86.0% of the Residential clients and accounts for 91.1% of the Residential class revenue. Within the Commercial classification nine rate schedules apply, however, the GSP rate schedule, which serves 7.8% of the Commercial clients, accounts for 53.4% of the Commercial class revenue. The rate schedule that generates the second most revenue in the Commercial classification is the GSS rate that serves 91.8% of the Commercial clients and accounts for

30.3% of the Commercial class revenue. While thirteen rate schedules apply to the Industrial classification, the GST rate schedule which serves 28.6% of the Industrial clients, accounts for 51.3% of the Industrial class revenue.

SUMMARY OF CORE RATE SCHEDULES ALL CLASSES

	Per Cent of Total MWH Sold	Per Cent of Total Revenue	Price Range cents/kWh
General Residential Service	31.0%	31.4%	21.85
General Service Secondary Voltage	12.7%	14.5%	24.64 - 27.51
General Service Primary Voltage	25.6%	26.6%	22.36 - 23.03
General Service Transmission Voltage	17.6%	15.4%	18.80 - 18.84

In February 2006 the Authority prepared a new Rate Schedule booklet to include the Special Industrial Incentive Rates previously approved. The current rate schedules are comprised of more than 80 subcategories to accommodate various service levels and load profiles. As shown on the Rates Table, the Authority presently serves all clients under 39 of the subcategories. Seven of the rate schedules are common to both the commercial and the industrial classifications.

As shown on the Rates Table, the average revenue for all power sold by the Authority was 21.53 cents/kWh during fiscal year 2009. The lowest average cost among the four popular rate schedules was 18.80 cents/kWh for GST–Industrial, with the highest average cost being 27.51 cents/kWh for GSS–Industrial.

The Authority's ten largest industrial clients (25.0% of the classification's consumption) paid an average of 17.47 cents/kWh during fiscal year 2009. This was 4.8% less than the industrial class average.

The Rates Table below shows all the rate schedules in use during fiscal year 2009 by the Authority's clients, with the average number of clients, total annual sales and average pricing for each rate schedule.

PRICE COMPARISONS

The Authority's average price per kilowatt-hour varies significantly among its client classifications. The Public Lighting class paid the highest average cost of 34.78 cents/kWh while the Industrial class paid the lowest average cost of 18.31 cents/kWh. These price variations are attributable to the differences in the cost of providing public service and socioeconomic objectives of the Commonwealth government and the Authority.

The average prices in cents/kWh for the Authority, Hawaii, and the U.S. are shown in the following table for the year ended June 30, 2009. The data for the State of Hawaii are provided because its geographical characteristics and fuel mix are similar to Puerto Rico's. The U.S. Department of Energy—Energy Information Administration (EIA) data were used as a reference to derive the pricing for the State of Hawaii and the U.S. The U.S. data are comprised of all fifty states and Washington D.C.

2009 AVERAGE PRICE COMPARISON
(Cents/kWh)

	Authority	Hawaii	U.S.
Residential	21.58	24.06	11.47
Commercial	22.32	21.38	10.15
Industrial	18.31	17.73	6.93
All Classes	21.53	20.90	9.86

ADJUSTMENT CHARGE

Prior to October 1999 the Authority's electric service rates consisted primarily of a base charge and a fuel adjustment charge. During that period, the base charge was comprised of the client and energy charges, and in most cases the demand charge. The energy charge included a fuel charge of $2.00 per barrel. The fuel adjustment charge recovered the Authority's fuel oil costs in excess of the $2.00 in the base charge. The fuel adjustment clause also recovered all other fuel-related costs.

The Authority revised the fuel adjustment clause in November 1999 to recover the cost of purchasing power from EcoEléctrica, a cogeneration plant, during its test and start-up period. On March 28, 2000, following the required public hearing, a permanent revision of the Authority's rate structure was approved that incorporated a purchased power charge in the electric service rates to recover its cost of purchased power from the EcoEléctrica plant. Since then the purchased power charge has been applicable for purchases from both cogenerators—EcoEléctrica and, subsequently, AES-PR. The rate structure revision also removed the $2.00 per barrel fuel charge from the base charge and included all fuel related charges in the newly defined adjustment charge. The fuel charge and the purchased power charge, both of which became effective June 5, 2000, are collectively shown on the client's bill as the adjustment charge.

RATES TABLE

Rate Schedule	Average Number of Clients	Total MWh	Total Revenue ($000)[1]	Average Cost Cents/kWh[2]
Residential Class[2]				
103,104 (RH-3)	41,004	150,962	27,797	18.41
109,110 (LRS)	145,044	485,418	94,478	19.46
111,112 (GRS)	1,138,704	5,731,181	1,252,068	21.85
Total Residential Class	*1,324,752*	*6,367,561*	*1,374,344*	*21.58*
Commercial Class[2]				
060 Telephone Booth	59	11	3	25.60
070-080 Cable TV	3	12,747	3,054	23.95
082 Security Cameras	133	256	66	26.00
211 (GSS)	118,857	2,330,512	574,299	24.64
212 (GSP)	10,118	4,527,901	1,012,550	22.36
213 (GST)	321	1,616,749	304,675	18.84
282 (SBS-P)	0	8,943	2,048	22.90
283 (SBS-T)	0	(7,426)	(1,432)	19.29
862	1	8,426	1,758	20.87
Total Commercial Class	*129,492*	*8,498,118*	*1,897,022*	*22.32*
Industrial Class[2]				
311 (GSS)	215	16,108	4,432	27.51
312 (GSP)	379	207,540	47,804	23.03
313 (GST)	257	1,641,045	308,521	18.80
333 (LIS)	2	181,043	23,106	12.76
343 (PPBB)	2	1,425	2,128	149.33
363 (TOU-T)	10	356,902	64,550	18.09
393 (SBS-T-TOU)	1	37,332	8,062	21.59
603 (SR-GST)	13	257,949	43,301	16.79
613 (SR-GST)	12	323,261	54,360	16.82
633 (SR-TOU-T)	1	10,304	1,667	16.18
643 (SR-TOU-T)	3	95,047	15,502	16.31
Industrial Class[2] (continued)				
653 (SR-TOU-T)	1	102,782	17,419	16.95
673 (SR-LIS)	-	22,013	4,492	20.41
963 (TOU-T)	3	35,847	6,640	18.52
Total Industrial Class	*898*	*3,288,597*	*601,985*	*18.31*
Other Classifications[2]				
Public Lighting				
2-41 (Non Meter P/L)	162	238,256	87,562	36.75
72 (PLG Bus Shelter)	3	798	177	22.13
73 (PLG Police)	5	33	6	18.32
414 (LP-13)	10	4,140	1,049	25.33
421 (PLG)	78	1,633	383	23.45
422 (PLG)	85	1,570	322	20.53
423 (PLG)	632	4,567	998	21.85
424 (PLG)	1,195	19,520	4,006	20.52
050-056 (Dusk to Dawn)[3]	–	3,172	681	21.46
Total Public Lighting	*2,168*	*273,691*	*95,183*	*34.78*
Agricultural				
711 (GAS)	1,322	30,523	6,912	22.65
Total Agricultural	*1,322*	*30,523*	*6,912*	*22.65*
Public Authorities				
513 (GST-Public Authority)	4	57,285	10,735	18.74
Total Public Authorities	*4*	*57,285*	*10,735*	*18.74*
Total[4] Other Classifications	*3,494*	*361,499*	*112,830*	*31.21*
Total	*1,458,636*	*18,515,775*	*3,986,181*	*21.53*

[1] Includes the Adjustment Charge.
[2] Calculated differences are due to rounding.
[3] Includes the residential fuel subsidy.
[4] Includes Public Lighting, Agricultural and Public Authorities classes.

The Authority invoiced $2,914.2 million through the adjustment charge in fiscal year 2009: $2,161.6 million for fuel and $752.6 million for purchased power. The adjustment charge constituted 73.1% of the Authority's $3,986.2 million electric revenue.

SUBSIDIES AND CREDITS

In accordance with various Commonwealth laws and regulations, the Authority provides subsidies to low consumption residential clients, energy conserving hotels, charitable organizations, agricultural clients, low-income clients with life sustaining equipment and small water companies distributing potable water.

The Authority's subsidies benefited 494,099 clients in fiscal year 2009, which is approximately 34% of its client base. The total value to the Authority for the benefits credited to these clients during fiscal year 2009 was $78.7 million. In fiscal year 2008, approximately 33% of the Authority's clients benefited from $70.7 million in subsidies. Funds for these subsidies were drawn from the Set Aside moneys discussed in the *Contributions in Lieu of Taxes and Set Aside* section in the *Financial* section.

RESIDENTIAL FUEL SUBSIDY

Under provisions of Act No. 106 of the Legislature of Puerto Rico, approved on June 28, 1974, the

Commonwealth began to subsidize the fuel adjustment charge (now the fuel charge, a component of the adjustment charge). In 1991 the subsidy qualification criteria were made more restrictive, to focus the subsidy on those clients truly in need. The new criteria are still in place and apply to the Authority's residential clients who consume up to 425 kilowatt-hours of electricity monthly or 850 kilowatt-hours bimonthly and meet the following criteria: those on the "Lifeline" residential rate (LRS), the government-administered public housing rate (RH-3), full-time students, the handicapped, and those 65 years of age or older. Additionally, all fuel subsidy recipients must be permanent residents of the Commonwealth of Puerto Rico and may receive the subsidy on only one dwelling. The subsidy is provided in the form of a credit against the recipient's electric bill. As of the end of fiscal year 2009, there were 300,000 clients or 23% of the total residential classification who qualified for subsidization. The purchased power component of the adjustment charge is not subsidized.

During fiscal year 2009 the total residential fuel subsidy was $30.6 million; during the previous fiscal year this subsidy totaled $24.3 million. The Commonwealth's contribution to the fuel charge subsidy program is deducted from the electric energy sales set aside. (See *Contributions in Lieu of Taxes and Other* section).

Until the end of fiscal year 1992, the subsidy was paid by the Commonwealth and was recorded as a receivable by the Authority. On June 30, 1991, the Commonwealth owed the Authority $94.9 million on account of the fuel charge subsidy program. In October 1991, the Authority and the Commonwealth entered into a non-interest bearing, fifteen-year payment plan for payment of this past due amount. In June 2004, the Legislature of the Commonwealth of Puerto Rico superseded the 1991 agreement with a revised agreement containing an eight-year payment schedule that totaled $55.7 million. This amount includes an allocation for past due Commonwealth government account receivables and the unpaid balance of the fuel adjustment subsidy. As of the end of fiscal year 2009 the balance owed by the Commonwealth **was** $18.9 million.

The Authority pays the entire fuel subsidy for all residential rate classifications until the price of oil reaches $18.00 per barrel. Once the price of oil exceeds $18.00 per barrel, the Commonwealth pays (by means of the electric energy sales set aside) the incremental price until it reaches $30.00 per barrel. This subsidy amount can not exceed more than $100 million per year. The client pays the incremental amount over $30.00. For the other recipients of the residential fuel subsidy, the Commonwealth pays (once again, by means of the electric energy sales set aside) the entire subsidy up to $30.00 per barrel. The Authority's monthly average cost of fuel in fiscal year 2009 ranged from a low of $ 50.15 per barrel in March 2009 to a high of $128.29 per barrel in July 2008; the average fuel cost for the fiscal year 2009 was $ 76.23 per barrel.

The residential fuel subsidy applies to the fuel adjustment charge for service at secondary voltage. The subsidy for qualifying residential clients is a sliding scale percentage that corresponds to their monthly consumption level. As shown on the table below, the subsidy percentage decreases as monthly consumption increases. The subsidy is not cumulative through the incremental blocks of consumption; for example, a client with a monthly consumption of 325 kWh would receive a 55% subsidy of the fuel adjustment charge. There is no subsidy if the monthly consumption exceeds 425 kWh.

Monthly Consumption (kWh)	% of Total Fuel Component Subsidized
0-100	90
101-200	75
201-300	65
301-400	55
401-425	*
Over 425	0

*For the first 400 kWh of consumption, 55% of the fuel charge will be subsidized; over 400 kWh the client will be charged 100% of the fuel charge for each additional kilowatt-hour up to 25 kWh.

RESIDENTIAL RATE SUBSIDY

The Authority serves its residential clients using three rates—GRS, LRS (Lifeline), and RH-3 (Public Housing). In fiscal year 2009, 86% of its residential clients were served using the GRS rate. The remaining residential clients were served using the LRS and RH-3 rates that are reserved for those who qualify as low-income; these rates have lower customer and energy charge components as compared to the GRS Rate.

During fiscal year 2009 the Authority served an average of 186,048 residential clients under the LRS and RH-3 rates, which provided a total subsidy of $18.3 million.

HOTEL SUBSIDY PROGRAM

Under Act No. 101 of July 9, 1985, the Authority started providing an 11% discount on its monthly electric bills to hotels that are certified by the Puerto Rico Tourism Company. This subsidy is designed to help conserve energy and promote tourism. In order to qualify for this discount the hotels are obligated to: develop programs for conserving and using energy more efficiently; submit evidence annually to the Commonwealth's Energy Affairs Administration, which administers the program, showing that they are implementing their programs; and remain current in paying their electric bills. Small hotels are only required to demonstrate compliance every five years. If a participating hotel does not pay its bill within 60 days, the hotel can be dropped from the program.

Act No. 266 of November 16, 2002, amended several articles of Act No. 101. The most notable change was the reduction in the number of rooms required to qualify for the discount from fifteen to only two. This subsidy, like the residential fuel subsidy, takes the form of a credit on the client's bill. During fiscal year 2009, an average of 185 establishments benefited from the $6.5 million in hotel subsidies.

CHARITABLE ORGANIZATIONS SUBSIDY

This subsidy applies to charitable organizations, such as churches, which provide religious services to the community at no charge. The subsidy enables any qualifying charitable organization to use the GRS rate (average cost of 21.85 cents/kWh for 2009) in place of the other applicable commercial rates (24.64 cents/kWh for GSS or 22.36 for GSP). The usage of GRS rate over GSS rate saved 2.79 cents/kWh in fiscal year 2009; GRS rate over GSP rate saved only 0.51 cents/kWh.

The Authority subsidized $3.5 million to serve an average of 2,963 charitable organizations in fiscal year 2009.

LIFE PRESERVATION SUBSIDY

The Life Preservation subsidy is available to qualifying low-income clients who require electrically powered essential medical equipment. The subsidy provides full credit for the electrical consumption of the medical device, based on the certification of need and hours of operation established by a physician from the Department of Health of Puerto Rico.

This subsidy served an average of 3,572 clients and amounted to $3.6 million in fiscal year 2009.

AGRICULTURAL SUBSIDY

The Agricultural service rate (GAS) is available to farmers, animal breeders and rural irrigation water suppliers. This rate is available for the clients whose load is up to 50 kVA. If the Authority did not provide the GAS rate to these clients they would be served under the more expensive GSS rate. The average price differential between the GSS and GAS rates was 2.27 cents/kWh using the Rate Schedule booklet.

This subsidy served an average of 1,322 clients and amounted to $613 thousand in fiscal year 2009.

RURAL ELECTRIFICATION AND IRRIGATION SUBSIDY

The Authority originally was constituted as the Puerto Rico Water Resource Authority which generated power from hydro-electric facilities. It included dams and infrastructure that also provided most of the island's water. The Authority still maintains jurisdiction over all dams on the island, however the Puerto Rico Aqueducts and Sewers Authority (PRASA) is the current public agency that is responsible for the water system on the island.

As part of its legacy responsibilities the Authority provides certain technical and maintenance services for dams that supply PRASA and some irrigation users. During fiscal year 2009 the Authority valued the cost of providing these beneficial services at $5.0 million in uncompensated expenses.

OTHER SUBSIDIES & CREDITS

In 2004 a subsidy was established for cooperative water companies that provide potable water to rural communities which were either not served or inadequately served by PRASA. In order to qualify for the subsidy, the rural water company must be registered with the Commonwealth, its operation must meet Commonwealth health standards and the water quality must comply with US EPA criteria. During fiscal year 2009 an average of nine rural water companies took advantage of this subsidy and received a benefit of approximately $4,500.

Since July 1, 2007, the Authority has allowed a 10% credit on its residential clients' basic rate charge for those clients who are current in their payments and pay the Authority directly from their personal bank account. Approximately 4,250 residential clients took advantage of this credit and saved $156,950 during fiscal year 2009.

The Authority provides a 10% credit for power, up to a maximum of $40 per month, to small commer-

cial clients with less than seven employees on the weekly payroll. This credit applies for up to three years. In fiscal year 2009 the credit provided a total benefit of $3,204 to two dozen clients.

The manufacturing industrial credit is provided to all new manufacturing industry clients and to the clients who expand their business operation. During fiscal year 2009, the Authority provided its manufacturing industry users a credit of $10.2 million; a credit of $7.0 million was provided during the previous fiscal year. This credit is discussed below in *Special Rates*.

SELECTED RATES

Over the last decade the Authority has developed a number of specialized rates to address certain pricing and operational issues for some of its large commercial and industrial clients. By design, these rates have limited applications and are almost exclusively available to clients purchasing power at the transmission level.

SPECIAL RATES

In order to promote an increase in industrial development in Puerto Rico, the Authority instituted five new special rates. These special rates offer a discount for new industries and expansion of existing industrials on or after February 12, 2002. New industrial clients receive a discount of approximately 11% on their total electric bill. Also, existing industrial clients that expand their operations receive a discount of approximately 11% on the demand, energy, and adjustment charges associated with its expansion. Public hearings regarding these rates were held in December 2002. These rates were available for five years effective July 30, 2003. While these rates expired on July 30, 2008, they are available to existing users to complete the balance of their five year term. The Authority has identified savings to industry from these rates of $10.2 million during the course of the fiscal year ending June 30, 2009. The five special rates are designated as follows:

- General Service at Transmission Voltage-Special (SR-GST)
- Time of Use Rate at Transmission Voltage-Special (SR-TOU-T)
- Large Industrial Service 115 kV-Special (SR-LIS)
- Standby Service at Transmission Voltage-Special (SR-SBS) and
- Time of Use Rate-Cool Storage Air Conditioning Systems-Special (SR-TOU-C)

Three of these rates—SR-GST, SR-TOU-T, and SR-LIS—were used during fiscal year 2009, while only SR-GST and SR-LIS were used in the previous two years by eligible clients. The SR-GST rate was used by 25 clients with a combined average cost of 16.80 cents/kWh. The SR-TOU-T Rate served five clients at a combined average cost of 16.62 cents/kWh; the SR-LIS Rate, with an average cost of 20.41 cents/kWh, was used by one client for part of the year.

LARGE INDUSTRIAL SERVICE RATE

In September 1997, the Authority adopted the Large Industrial Service (LIS) rate in order to encourage large industrial clients to remain part of its client base. To be eligible for this rate clients must meet the following criteria: receive service at 115 kV; have a demand of 12,000 kW or greater; a minimum load factor of 80%; and an average monthly power factor of 95% or more. The Authority served only two clients for the past two fiscal years 2008 and 2009 using the LIS Rate. The average cost per kWh for this rate was 12.76 cents/kWh in fiscal year 2009, making it the lowest among all the existing rates offered by the Authority. Its average cost was 17.07 cents/kWh in fiscal year 2008.

TIME-OF-USE RATES

Time-of-Use (TOU) rates are a component of the Authority's Demand-Side Management (DSM) program. (For a discussion on the DSM program refer to *Demand-Side Management and Energy Conservation Programs* in the *Demand and Energy Forecast* section.) These rates are designed to encourage shifting consumption from on-peak hours to off-peak hours when the total system demand is otherwise lower. The Authority offers several TOU rates for commercial and industrial clients. Currently these rates are only offered to the Authority's commercial and industrial clients.

On May 28, 1996, the Authority's Governing Board adopted Resolution Number 2160, which approved revised load requirements, thereby increasing the number of clients eligible for TOU rates. As of June 30, 2009, a total of 19 clients were served under these rates, resulting in $113.8 million in revenues, approximately 19% of the total for the industrial classification. Ten clients were served using the TOU-T (time of use at transmission voltage) rate at an average cost of 18.09cents/kWh. The SBS-T-TOU (time of use at standby service at transmission voltage) rate served only one client at an average cost of 21.59 cents/kWh in fiscal year 2009.

Five clients were served under SR-TOU-T (Special time of use rate at transmission voltage) rate. The SR-TOU-T Rates are available under Special Rates to manufacturing clients who are either new or have added to their electric load during the past fiscal year. The combined average cost for these three SR-TOU-T rates serving these five clients was 16.62 cents/kWh for fiscal year 2009 .

The last TOU rate utilized in fiscal year 2009 was the TOU-T rate, which applies to industrial clients who have a load demand of 1,000 KVA to 3,000 KVA. During fiscal year 2009 this TOU-T rate served three clients with an average cost of 18.52 cents/kWh.

Another available TOU rate is the Cool Storage Air Conditioning Systems (TOU-A/C) commercial rate. Although this rate has been in existence for almost two decades, it has attracted few clients and the last one changed to a conventional rate effective the beginning of the past fiscal year.

POWER PRODUCERS AT BUS BAR RATE

On March 28, 2000, the Authority's Governing Board, under Resolution Number 2812 approved the Power Producers at Bus Bar (PPBB) rate. This rate, which became effective June 5, 2000, is only available to large power producers who are connected at 230 kV and have a power purchase agreement with the Authority for all its electrical output. In addition, the power producer must have at least an 85% equivalent availability. Under this rate a power producer can purchase power from the Authority for startup, scheduled maintenance, and for backup power.

Presently, only EcoEléctrica and AES-PR qualify for this rate. The black-start energy requirements for these two power producers are 12.0 MW and 38.7 MW, respectively.

The Authority generated $2.1 million in revenues from the sale of 1,425 MWh of power from the two cogenerators in fiscal year 2009.

STANDBY SERVICE RATE

The Standby Service Rate (SBS) is applicable to industrial or commercial clients who generate power for their own use and not for resale. This rate schedule provides four levels of service: supplementary, auxiliary, maintenance, and interruptible power. When the client's generator is unable to generate enough power needed to satisfy its load, whether because of a limitation or a scheduled or forced outage, then the client starts to receive its needed power automatically from the Authority. The demand, customer, and energy-related costs for this rate are the same as those in the corresponding service class that would apply, namely GSP, GST, TOU-P, or TOU-T rates.

The only standby rate in use at the end of fiscal year 2009 was for one industrial client utilizing the SBS-T-TOU rate. This was discussed above in *Time-of-Use Rates* above. The average cost of the SBS rate serving the industrial client was 21.59 cents/kWh. The Authority derived $8.1 million in revenue from the sale of 37,332 MWh from this rate.

SECURITY CAMERAS RATE

As part of an increased public safety program, security camera surveillance systems and wireless telecommunication equipment have been installed on the Authority's poles and structures.

The Authority instituted a temporary rate for unmetered small load service (USSL) in July 2007 and subsequently added this new rate in its rate structure in January 2008. The rate is applicable to all security cameras and communication equipment installed on the Authority's electric poles throughout the entire island of Puerto Rico. Before installation of these security devices, the client is required to provide all equipment specifications to the Authority's Director of Generation, Transmission and Distribution. The electric consumption for each installed security camera may not exceed 200 kWh per month.

During fiscal year 2009 an average of 133 clients used this rate and paid an average cost of 26.00 cents per kWh.

COST OF SERVICE

A cost of service study is an analytical tool that determines the proper allocation of capital investment and expenses associated with providing electric power. The results of the studies are used when designing various rate schedules.

In fiscal year 2008 the Authority performed a cost of service study based on fiscal year 2007 data. The study employed methodologies that are commonly accepted in the electric utility industry.

The revenues, expenses and surplus or deficiency data from the most recent cost of service study for major rate schedules and classes of service are summarized below:

2008 COST OF SERVICE RESULTS BASED ON 2007 DATA
($ millions)

Rate Schedule/Class	Collected Revenues	Cost to Serve	Recovered Cost Percentage
Residential	1,299.5	1,487.6	87.4
Commercial	1,701.8	1,609.5	105.7
Industrial	644.0	568.9	113.2
Other Classes	103.8	124.9	83.1

It should be noted that the results of a Cost of Service study are not the only criteria used to design rates. The Authority uses other important criteria including socioeconomic, energy conservation, and load management objectives.

CONSULTING ENGINEERS RECOMMENDATION

The 1974 Agreement stipulates that after payment of all current expenses, the remaining net revenue must equal or exceed 120 per centum of outstanding debt service. The Consulting Engineers monitors on an ongoing basis that the Authority's rate schedules will generate sufficient revenues to pay its current expenses and have adequate debt service coverage. The Authority's debt service coverage ratio for fiscal year 2009 was 1.45. The debt service coverage for fiscal year 2010 is forecasted to be 141% based on the Authority's amended Annual Budget discussed in the *Financial* section.

The Consulting Engineers has reviewed the Authority's rate schedules and other pertinent data and believes that the Authority will receive sufficient revenues in fiscal year 2010 to cover current expenses, to make all required deposits in accordance with the 1974 Agreement's dictates, and to exceed its 120% debt service coverage requirement. Refer to *Net Revenues* in the *Financial* section for further discussion of debt service coverage.

FINANCIAL

ANNUAL BUDGET

The Annual Budget, prepared in conformance with Section 504 of the Trust Agreement, consists of four statements and two exhibits. The four Statements are: a pro forma income statement for the ensuing fiscal year; a projection of capital expenditures also for the ensuing fiscal year; a summary of capital expenditures and the sources of construction funds to support the expenditures; and a schedule of funds to be provided by the Government Development Bank for Puerto Rico (GDB). The two exhibits are a five-year projection of debt service and Contractual Obligations and Contributions in Lieu of Taxes and Other.

In April 2009 an amendment to the 2008-09 Annual Budget of Current Expenses and Capital Expenditures was developed; it revised items such as the projected energy sales, fuel consumption and costs, purchased power costs, and projected net revenues. The amended Annual Budget was adopted by the Governing Board on April 21, 2009. The amended Annual Budget is the budget which applies in this Annual Report when reference is made to the 2008-09 Annual Budget.

The Proposed Annual Budget of Current Expenses and Capital Expenditures – Fiscal Year 2009-2010 was approved in May 2009 by the Consulting Engineers prior to the Governing Board's adoption in June 2009.

In July 2009 the Authority revised its Capital Improvement Program for fiscal years 2011 and 2012 by decreasing the total budget from $350 million for each year to $300 million and increasing the budget for fiscal year 2014 from $350 million to $400 million; the Governing Board adopted the revised Capital Improvement Program on July 21, 2009.

In January 2010 the Authority prepared an amended 2009-2010 Annual Budget to address higher fuel costs than had been projected. The amended Annual Budget incorporated higher revenues resulting from the increased fuel costs and from an energy theft recovery initiative, lower projected operating expenses, and modifications to debt financing. In view of the significant revisions in the amended budget and their affect on the Authority's financial status regarding Trust Agreement requirements, the Consulting Engineers have incorporated the amended budget in the discussions and evaluations within the *Financial* section and *Appendices* of this Annual Report.

REVENUES

Total revenues for fiscal year 2010 are forecasted to be $3,604,632,000 compared to the actual revenues in fiscal year 2009 of $4,007,267,000, a decline of 10%. The Authority's revenues for fiscal year 2009 include more than $8,400,000 for billings of power lost to theft as a result of a significant new initiative to recover these losses. Beginning in fiscal year 2010 the Authority has adjusted the forecasted total revenues from electricity to reflect recovery of sales lost to theft. This additional revenue is forecasted to be $16,955,000 in fiscal year 2010 and $50,000,000 per year for fiscal years 2011 through 2014. For fiscal years 2011 through 2014 total revenues are forecasted to be $3,944,854,000, $4,298,742,000, $4,470,276,000, and $4,597,297,000 respectively. *Appendix II, Income Statement,* presents the Authority's income statements (including interest income) for fiscal years 2009 through 2014.

As shown on *Appendix I, Intermediate-Term Revenue Planning Forecast,* base revenues from sales of electricity for fiscal year 2009, excluding fuel and purchased power included in the adjustment clause, were $1,071,966,000 and are forecasted to be $1,041,657,000 for fiscal year 2010 or a decrease of 2.8%. The projections for fiscal years 2011 through 2014 are $1,033,043,000—a decrease of 0.8%, $1,031,436,000 –a decrease of 0.2%, $1,035,536,000 —an increase of 0.4%, and $1,044,806,000—an increase of 0.9%, respectively.

ACCOUNTS RECEIVABLE

The Authority's accounts receivable balance for fiscal year 2009 was $1,028.9 million or approximately 3.1% less than the previous year. Of the $1,028.9 million balance, $471.4 million applied to government clients, an increase of 31.9% over the previous fiscal year, and $557.5 million applied to general clients, which is a decrease of 20.8% from the previous fiscal year.

The Auditor's Report for fiscal year 2009 shows the allowance for uncollectible accounts increased to $163.6 million in the past fiscal year; this was an increase of $19.8 million or 14% over the previous year.

At the end of fiscal year 2009 the following five government agencies accounted for approximately 48% of the total government amounts owed to the Authority:

Client	A/R Balance
Department of Education	$66.3 million
Aqueducts and Sewer Authority (AAA)	$63.3 million
Public Building Authority	$58.5 million
Port Authority	$33.2 million
Medical Services Administration	$14.0 million

The Authority has made a concerted effort to collect overdue accounts from general clients. The actions taken include meeting with political groups, disconnecting electrical service, referring clients to collection and credit rating agencies, and setting up a payment schedule.

COMPARISON OF BUDGETED EXPENSES TO ACTUAL EXPENSES FY 2009 AND FY 2010 PROJECTIONS

(in thousands)

Current Expenses	2009 Amended Budget	2009 Actual	2009 Difference	2010 Amended Budget	Change from Previous Year
Fuel Cost	$ 1,848,270	$ 1,919,789	$ 71,519	$ 1,529,493	$ (390,296)
Purchased Power	670,914	671,849	935	711,701	39,852
Other Expenses	59,674	62,271	2,597	57,119	(5,152)
Transmission & Distribution	140,215	162,334	22,119	146,601	(15,733)
Maintenance	246,879	225,107	(21,772)	237,727	12,620
Customer Actng & Collection	113,202	111,126	(2,076)	112,674	1,548
Administrative & General	201,410	222,477	21,067	142,428	(80,049)
Interest Charges	3,476	2,819	(657)	3,998	1,179
Total	**$ 3,284,040**	**$ 3,377,772**	**$ 93,732**	**$ 2,941,741**	**$ (436,031)**

EXPENSES

The Authority's budget for Current Expenses for fiscal year 2009 and the amounts actually expended, as well as those budgeted for fiscal year 2010 are shown below.

In fiscal year 2009 the Authority's current expenses were 3% or $93.7 million more than that budgeted. Extracting fuel and purchased power the remaining current expenses were also 3% more than that budgeted.

Current expenses less fuel oil, purchase power and interest charges are projected to decrease 11% in fiscal year 2010 as compared to actual expenses in fiscal year 2009; a reduction of 2% is forecasted in fiscal year 2011, with 0.2% annual decreases for fiscal years 2012 through 2014. The largest contribution to the reduction of current expenses less fuel oil, purchased power and interest between fiscal years 2009 and 2010 is the $80.0 million drop in administrative and general costs. This significant savings is based principally on two factors: more than 60% of the savings reflect the difference in the budgeted costs for retirees under a new health care plan, while most of the balance is attributed to savings associated with employees taking early retirement during fiscal year 2010.

OPERATING AND MAINTENANCE EXPENSES

In fiscal year 2009, total Operating and Maintenance (O&M) expenses were $3,377,772,000 and for fiscal years 2010 through 2014 are forecasted to be $2,941,741,000, $3,205,620,000, $3,520,599,000, $3,668,155,000 and $3,771,444,000. *Appendix III, Detail of Operating and Maintenance Expenses,* shows O&M expenses by category for fiscal years 2009 through 2014.

The cost of fuel oil is the largest component of O&M expenses. During fiscal year 2009 approximately 69% of the System's energy was generated by the Authority's oil-fired plants, with a total fuel cost of $1,920 million; this constituted 57% of the total O&M expenses for the year. The fuel prices forecasted in the Authority's amended budget, coupled with the forecasted decline in energy sales, result in the projected total cost of fuel decreasing substantially in fiscal year 2010, then rebounding the following year and increasing each year to 2014. The actual average cost of fuel in fiscal year 2009 and the forecasted costs during fiscal years 2010 through 2014 are discussed in the *Fuel Mix* section above. In addition, *Appendix IV, Annual Generation, Fuel Consumption, and Fuel Costs for Thermal Stations,* shows the cost of fuel and the generating efficiency (kWh generated per barrel) for each major generating facility. Actual data are shown for fiscal year 2009 and forecast data through 2014.

The ratio of O&M expenses to Total Operating Revenues in fiscal year 2009 was 84.3%. In fiscal years 2010 through 2014 it is projected to be 81.6%, 81.3%, 81.9%, 82.1% and 82.0%, respectively.

DEPRECIATION EXPENSE

Appendix IX, Depreciation Expense, shows the actual depreciation accrual for fiscal year 2009 as $304,468,833. The estimates for the ensuing five fiscal years are $343,245,000, $352,245,000, $361,245,00, $370,245,000, and $379,245,000, respectively. Depreciation Expense is excluded from statements required for Trust Agreement purposes.

The Consulting Engineers completed a comprehensive depreciation review of the Authority's Plant-in-Service in May 2000. The overall result was three-tenths of 1% increase in the Authority's composite annual depreciation accrual rate (expense).

The review confirmed statistically that the production plant's average service life is increasing. It also showed that net negative salvage (cost of removal less salvage) of retired capital equipment was escalating due to increased labor costs and the costs associated with the removal of hazardous materials. This increased cost of removal component contributes to an increase in the annual composite depreciation accrual rate.

The Authority's Governing Board reviewed and accepted the study's results and in fiscal year 2001 the Authority implemented the recommended depreciation accrual rates.

Data is presently being collected to update the depreciation requirements as of the end of fiscal year 2009.

NET REVENUES

Net Revenues, as defined under the Trust Agreement, are shown in *Appendix II, Income Statement,* as *Balance to Revenue Fund.* For fiscal year 2010 the Net Revenues are forecast to be $662,891,000 compared to $629,496,000 in fiscal year 2009. For fiscal years 2011 through 2014 net revenues are forecasted to be $739,234,000, $778,143,000, $802,121,000 and $825,853,000, respectively.

Based on the amounts shown in *Appendix II, Income Statement*, the ratio of Net Revenues to Principal and Interest Requirements (Debt Service Coverage) was

1.45 in fiscal year 2009. The Debt Service Coverage is projected to be 1.41, 1.61, 1.58, 1.49 and 1.44 for fiscal years 2010 through 2014, respectively. The Debt Service Coverage graph shows the five-year history and the five-year projection of the ratio of Net Revenues to Principal and Interest Requirements.

The Authority's total revenues include the Commonwealth Government's estimated annual fuel charge subsidy payments to the Authority, which are deducted from the electric energy sales set aside. (See *Contributions in Lieu of Taxes and Set Aside* section below). In fiscal year 2009 the Commonwealth's fuel charge subsidy amounted to $30,579,000. The subsidy is forecasted to be $21,297,000, $20,445,000, $19,957,000, $19,518,000, and $19,554,000, respectively, in fiscal years 2010 through 2014.

The forecasted net revenues for the next five years are sufficient to meet the 1974 Trust Agreement's coverage requirement for the outstanding Power Revenue Bonds as well as those expected to be issued in the interim. (See *Appendix II, Income Statement.*)

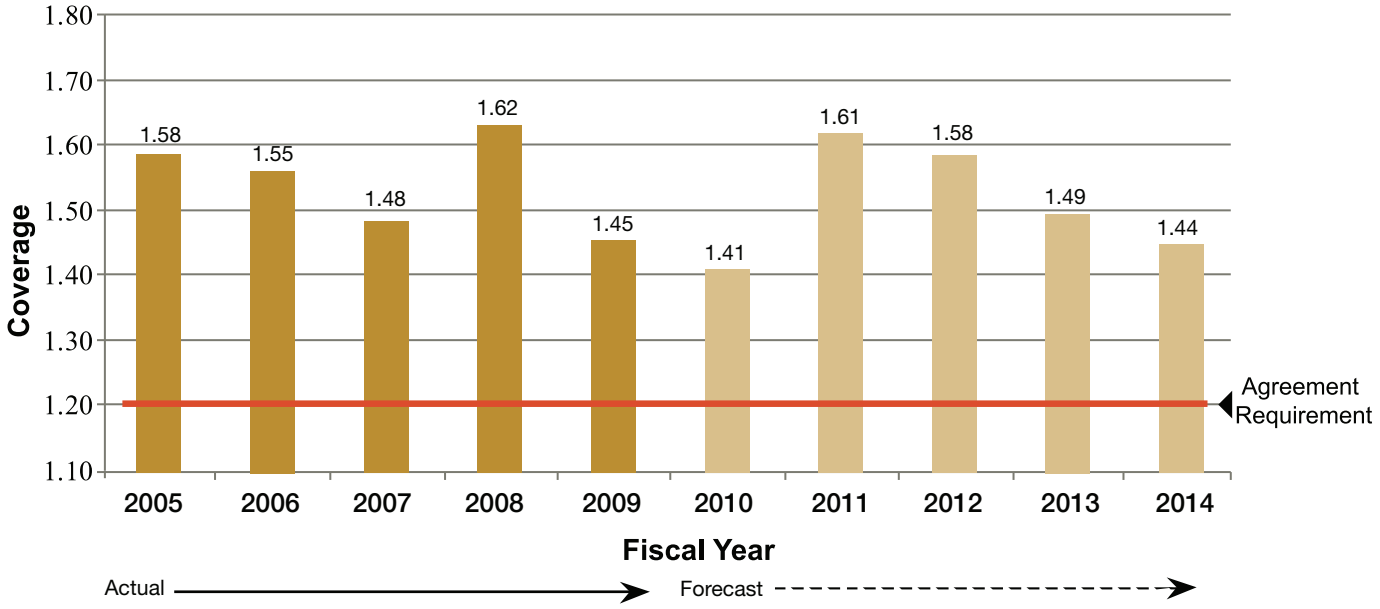
CONTRIBUTIONS TO THE COMMONWEALTH

CONTRIBUTIONS IN LIEU OF TAXES AND OTHER

The Authority, in accordance with the Authority Act, as originally enacted, was required to set aside annually from its Net Revenues an amount equal to 6% of its annual gross electric energy sales, computed on the basis of an annual average fuel price capped at $30 per barrel, to be paid to the island's municipalities as contributions in lieu of taxes (CILT). The Authority was also required to set aside annually from its Net Revenues an additional amount equal to 5% of its annual gross electric energy sales, computed on the basis of an annual average fuel price capped at $30 per barrel, to be paid to the Commonwealth government as contributions in lieu of taxes. These combined contributions in lieu of taxes, amounting to 11% of the Authority's annual gross electric energy sales, were to be paid from the Authority's Net Revenues after certain defined expenditures and subject to compliance with its obligations under both the now defeased 1947 Trust Indenture and the existing 1974 Agreement. The contributions in lieu of taxes for distribution to the municipalities were and are paid to the Commonwealth's Secretary of the Treasury.

Prior to 1981 the Authority was not required to increase its rates and charges to make the CILT payments to the island's municipalities or to fund the electric energy sales set aside. However, with the change in the law at the time of the 1981 rate increase, the Authority became legally obligated to make the CILT payments to the municipalities and fund the electric energy sales set aside based upon the availability of Net Revenues. If the Net Revenues in any year were not sufficient to cover both the CILT and the electric energy sales set aside, the amounts were reduced to the amount available, and any remaining balance did not carry forward as a liability in future years

Debt Service Coverage Fiscal Years 2004-2014



In 1991 the Commonwealth government and the Authority reached an agreement whereby the Commonwealth government would forego its 5% contributions in lieu of taxes. The Authority would use those moneys, now known as the "electric energy sales set aside" as follows: One-fifth of the set aside is to be applied to cover the cost of the Commonwealth government's residential fuel charge subsidy program subsequent to June 30, 1991 (see the following discussion). If any balance remains, it is to be used to reduce the amount owed by the Commonwealth to the Authority on account of such subsidy as of June 30, 1991. Another one-fifth of the set aside must be paid to the Commonwealth government's Secretary of the Treasury for distribution to the municipalities, thereby increasing the CILT due the municipalities from 6 to 7%. The remaining three-fifths of the set aside is to be used for any lawful purpose of the Authority.

In May 1998, the Municipality of Ponce filed a complaint seeking payment from the Authority for the full amount of the contributions in lieu of taxes and electric energy sales set aside for prior fiscal years. The island's other 77 municipalities subsequently joined the suit. The complaint challenged the Authority's disposition of Net Revenues in making deposits to certain funds under both the 1947 Trust Indenture and the 1974 Agreement for the purposes of paying the costs of capital improvements. The municipalities sought retroactive payment of the amount by which their share of the contributions in lieu of taxes and electric energy sales set aside had been reduced by such application.

The Authority settled this litigation with the municipalities by offering a monetary payment of $68 million and $57 million for electric infrastructure projects, for a total of $125 million.

In 2004 legislation was enacted that revised the formula for computing contributions in lieu of taxes and set aside. The amended legislation requires that 11% of the Authority's gross electric energy sales be distributed to fund all government rate subsidies programs, to pay contributions in lieu of taxes to the municipalities, to finance the Authority's Capital Improvement Program and for other legal purposes. The amendment changed the calculation of contribution in lieu of taxes payable to the municipalities in that it will be the greatest of the following amounts: 1—twenty-percent of the Authority's Adjusted Net Revenues (Net Revenues, as defined in the 1974 Agreement), less the cost of government rate subsidies; 2—the cost collectively of the actual annual electric power consumption of the municipalities; or 3—the prior five-year moving average of the contributions in lieu of taxes paid to the municipalities collectively. If the Authority does not have sufficient funds available in any year to pay the contributions in lieu of taxes then the difference will be accrued and carried forward for a maximum of three years.

The law permits the Authority to reduce the CILT payments / remittances to municipalities by the balance of the accounts receivable due the Authority for electric service provided to municipalities. The Authority's CILT obligation for fiscal year 2009 was $187.7 million, which was the value of the electric power consumed by the municipalities during the fiscal year. During fiscal year 2009 the Authority was credited with remitting $113.0 million in payments and services. The difference of $74.7 million will be carried forward for payment by the Authority over a maximum of three fiscal years. In fiscal year 2009 the Authority also made annual installments of $11.4 million and $5.9 million towards the unpaid CILT balances from fiscal years 2007 and 2008, respectively. At the end of fiscal year 2009, the unpaid CILT balance totaled $97.9 million.

The amount of $181.4 million for Contributions in Lieu of Taxes and Other shown on *Appendix II, Income Statement,* includes $42.1 million for the hotel subsidy, the residential fuel subsidy, and the rural electrification and irrigation subsidy, which are discussed in the *Rates* section, and a payment of $8.9 million to amortize the outstanding line of credit used in the settlement of the municipalities lawsuit.

ECONOMIC INCENTIVES ACT

To spur economic development the Commonwealth Government enacted the Economic Incentives for the Development of Puerto Rico Act (Economic Incentives Act) in May 2008. The Economic Incentive Act is scheduled to be in effect for ten years starting on July 1, 2008.

In comparison to the Tax Incentives Act of 1998, which expired at the end of fiscal year 2008, the Economic Incentive Act expands the scope of businesses eligible for tax exemptions and credits. The three sections of the Economic Incentive Act that may most effect the Authority are the Energy Investment Credit, the Energy Cost Credit, and Wheeling. The tax credits in the Economic Incentive Act are based on the preferential income tax on Industrial Development Income.

The Energy Investment Credit section establishes a one-time tax credit of fifty percent for investments by eligible businesses in systems and equipment for generating electrical energy and for investments which improve efficiency. The energy generation may be for self consumption or for commercial resale. The amount of the tax credit for new self generated capacity is limited to 25% of the eligible firm's income tax. The tax credit for commercial generation is limited to $8 million per eligible business and $20 million per year in the aggregate.

The Energy Cost Credit allows eligible businesses to receive a credit of 3% of the cost of their industrial energy consumption against income tax. Additional credits are available based on the number of employees and payroll cost up to a total maximum credit of 10% of the payments made to the Authority for energy consumed in the operation of the eligible business. The maximum credit will be reduced 1% per year between 2013 and 2017. The aggregate amount for this tax credit is capped at $75 million per fiscal year and $600 million through fiscal year 2018.

Under the Wheeling provision, in 2010 the Authority will establish the technical criteria and tariffs that will apply to qualifying generators for moving their power—wheeling—on the Authority's system to the generator's clients or for the Authority to purchase the generator's power for general distribution to the Authority's clients. The Economic Incentive Act establishes a new administrative entity, the Energy Matters Office, whose duties include overseeing the implementation of the wheeling provision. The Energy Matters Office will have the power to assign an arbitrator to establish rates between the Authority and a qualifying generator if there is a disagreement between the two parties.

Funding for the tax credits established by the Economic Incentive Act will be drawn from the Commonwealth's General Fund and partially from payments by the Authority. The Authority's payments will be based on reductions in operating costs, improved efficiencies, revenues from wheeling and lower costs in purchased power. The Authority's payments may not in any way be subsidized or passed through to its clients and the Authority is prohibited from reducing its number of employees or payroll. The tax credit will end if the Authority's average retail cost of power is 10 cents/kwh for two consecutive years.

The Authority incurred no costs during fiscal year 2009 attributable to the Economic Incentive Act, however, it estimates costs in fiscal year 2010 will be $3.2 million and total $44.0 million in the five years ending in fiscal year 2014.

FINANCING

LONG-TERM CAPITAL FINANCING

The Government Development Bank for Puerto Rico (GDB) is the primary fiscal agent for the Commonwealth of Puerto Rico and is responsible for overseeing and maintaining the Commonwealth's overall creditworthiness. In this capacity it coordinates all bond issues and lines of credit for the Authority as well as other agencies of the commonwealth government and municipal governments. The GDB also sets the timing of all bond sales.

The Authority's actual and forecasted capital expenditures for fiscal years 2009 through 2014 are summarized by category in *Appendix VI, Capital Expenditures. Appendix X, Details of Capital Improvement Program,* provides a breakdown by Budget Item Number of the expenditures shown in *Appendix VI.* The Authority's sources of funds and anticipated financing needs for fiscal years 2010 through 2014, as well as those realized in fiscal year 2009, are presented in *Appendix VII, Sources of Funds for Capital Expenditures.*

The U.S. Department of Agriculture's Rural Utilities Service (RUS), which replaced the Rural Electrification Administration (REA) in a 1994 reorganization, oversees various programs of both the defunct REA and the Rural Development Administration. One of the REA's programs provided low interest financing for rural electrification projects. Over the years, the Authority took advantage of this opportunity to develop portions of its System. As part of the Series KK and Series MM refunding, the Authority refinanced all of the outstanding REA Power Revenue Bonds except for the Series I issue with a face value of $26.6 million.

As of June 30, 2009, the Authority had $6,030,691,000 in Power Revenue Bonds outstanding, including REA bonds. (See *Appendix V, Debt Service Coverage Under the 1974 Trust Agreement.*)

The debt service coverage for all bonds outstanding under the 1974 Agreement as of June 30, 2009 was 145%, exceeding the 1974 Trust Agreement's 120% requirement.

INTERIM FINANCING

Lines of Credit & Notes Payable

As of the end of fiscal year 2009 the Authority had ten lines of credit; seven for construction financing and three for fuel financing and working capital. There are also two term loans that are financed through a large commercial bank.

Two of the financings relate to the settled litigation with the municipalities of Puerto Rico. One is a $64.2 million term loan to fund payments made under the settlement agreement regarding litigation with the municipalities. As of June 30, 2009 the balance was $48.1 million, of which $39.1 million is considered long-term. There are five years remaining on this note. The other is a $57 million credit line for infrastructure improvements which matures on June 30, 2010.

There are two lines of credit with commercial banks for fuel financing that had their terms extended by one year during fiscal year 2009; one with a limit of $200 million which matures on June 30, 2010, the other has a credit limit of $275 million, previously $225 million, and expires on June 30, 2010.

In June 2003 the Authority and GDB entered into an agreement for a $200 million credit line to be used for interim financing of the Capital Improvement Program. In June 2006 this $200 million credit line was refinanced with a bridge loan between the Authority and a large commercial bank. During the present fiscal year the term of the credit line had been extended by 13 months and expires on July 31, 2010. As of June 30, 2009 the credit line had been exhausted.

During fiscal year 2009 the Authority established an additional line of credit to be used for interim financing of the Capital Improvement Program; its limit is $96 million of which $48 million was available at the end of the year.

There are two $100 million lines of credit related to the restoration of the Palo Seco Power Plant. One is

LINES OF CREDIT – TERM LOANS AS OF JUNE 30, 2009
(in thousands)

Purpose			
Lines of Credit-Construction Financing		Limit	Outstanding Debt
1	Construction-Interim Financing CIP	$ 200,000	$ 200,000
2	Infrastructure Muni Settlement	57,000	56,961
3	Isabela Irrigation System	25,354	6,104
4	Capital Improvement Program	400,000	250,000
6	Emergency Liquidity[3]	96,000	48,000
7	Palo Seco Restoration & Extra Expenses	100,000	50,000
8	Palo Seco Restoration & Extra Expenses	100,000	50,000
	Subtotal	*$ 978,354*	*$ 661,065*
Lines of Credit-Operational Financing		Limit	Outstanding Debt
1	Operational Financing - Fuel	$ 200,000	$ 199,892
2	Fuel Financing	275,000	275,000
3	Interest Basis Swap Collateral	150,000	11,622
	Subtotal	*$ 625,000*	*$ 486,514*
	Total	*$ 1,603,354*	*$ 1,147,579*
Term Loans		Total Note	Balance
1	Muni's Settlement Agreement[1]	$ 64,208	$ 48,058
2	Commonwealth Debt - Residential Fuel Sub.[2]	41,585	21,741
	Total		*$ 69,799*
	Outstanding Credit Lines & Term Loans		*$ 1,217,378*

1) $39,058 considered long-term
2) $16,363 considered long-term
3) $48,000 considered long term

with a commercial bank and the other with the GDB. The credit line with the GDB was extended by one year during fiscal year 2009 and will expire on June 30, 2010. The credit line with the commercial bank matures on December 18, 2009. At the end of fiscal year 2009 there were no monies available under these lines of credit.

During fiscal year 2007 the Authority established a $400 million credit line with a commercial bank for interim financing for its Capital Improvement Program. As of June 30, 2009, $150 million was available under this credit line.

There is a credit line for the Authority's restoration of the Isabela Dam of approximately $25.4 million. As of June 30, 2009, approximately $6.1 million had been withdrawn. The Authority expects to be reimbursed for any monies spent under this credit line from the Commonwealth government.

In December 2004, the Authority sold $55.7 million of the Commonwealth Government's accounts receivable to a commercial bank for a discounted amount of $41.6 million. The notes yield an interest from 2.6% to 4.4%. The Authority is responsible to service the note; however the Commonwealth will make annual payments to the Authority for the total amount due, therefore making the transaction a pass-through. The outstanding balance as of June 30, 2009 was $21.7 million of which $16.3 is considered long-term. This note corresponds to appropriations that were intended to pay part of the accumulated debt of various government agencies with the Authority and the outstanding balance of certain subsidies as of December 31, 2006. This note is considered extra-constitutional debt of the Commonwealth and the Legislature has assigned 1% of the proceeds from the sales and use tax towards the $6.3 million annual payment.

During fiscal year 2009 the Authority initiated a $150 million line of credit with the GBD for covering collateral on its power revenue bonds that are based on interest basis swaps. This line of credit expires on December 31, 2009. As of June 30, 2009 $11.6 million has been withdrawn.

In summary, as of the end of fiscal year 2009 the Authority had credit lines totaling $1,603.4 million, of which $1,147.6 million had been withdrawn, and term loans with a remaining balance of $69.8 million for a total balance of $1,217.4 million.

The Authority is evaluating paying down a portion of their interim financing debt with some of the proceeds of the next long term financing which is contemplated in the amended annual budget for fiscal year 2010.

CAPITAL IMPROVEMENT PROGRAM

The fiscal year 2010 Capital Improvement Program (CIP) projects a five-year period of expenditures for extensions and improvements to the System. An overview of the scope of these projects for fiscal year 2010 is provided below and is summarized by functional group in *Appendix VI, Capital Expenditures.* An expanded presentation of the CIP is in *Appendix X, Details of Capital Improvement Program,* which lists the extensions and improvements by Budget Item Number (BIN) through fiscal year 2014.

The Authority develops the CIP on the basis of supporting its objectives of providing dependable electric power service to the island of Puerto Rico at the lowest cost, consistent with applicable environmental and social obligations.

The total capital expenditures in fiscal year 2008 established an historically high level principally because of the costs associated with the construction of the Authority's two newest production plant projects, San Juan Units 5&6 and the new combustion turbines at Mayagüez. The budget for fiscal year 2009 was established at $446.0 million, which was 33% less than the previous year's actual expenditures, in large measure because of the scheduled completion of these projects. The combined cycle San Juan Units 5&6 entered service during the second quarter of fiscal year 2009. The eight new combustion turbines at Mayagüez were in service by the end of the fiscal year.

Actual capital expenditures during fiscal year 2009 were $480.2 million, or 7.7% above the budget. Fiscal year 2009 marked the first year of planned significant reductions in the capital improvement program expenditures over the next four years. The CIPs in million of dollars are projected to be $350.0, $300.0, $300.0, $350.0, and $400.0 for fiscal years 2010 through 2014, respectively. These figures do not include Contributions in Aid of Construction, i.e., capital contributed by either the Authority's clients, FEMA or the Commonwealth Government for special construction services. However, allowance for funds used during construction (AFUDC) and annual cost escalations are included.

The table below shows by functional group the amounts budgeted for the Capital Improvement Program and that actually expended in fiscal year 2009:

BUDGETED FY 2009 CIP TO ACTUAL CIP AND FY 2010 CIP BUDGET
(in thousands)

	2009 Budget	2009 Actual	2010 Over Budget	2010 Budget
Production	$ 185,328	$246,578	$ 61,250	$ 128,014
Transmission	104,638	91,508	(13,130)	117,151
Distribution	80,489	105,028	24,529	75,322
Other	75,551	37,100	(38,451)	29,513
Total	***$446,006***	***$480,214***	***$34,208***	***$350,000***

The Authority's CIP budget for fiscal year 2010 is 27.1% less than the previous year's actual expenditures. As discussed above, the largest budget item reduction is in the cost of production plant expansion, however, reductions apply to all functional groups with the exception of transmission which is forecasted to increase by 28% over fiscal year 2009 spending levels. The transmission budget reflects priority projects which were deferred or constrained while system operation restraints were in place because of the prolonged outages at the Palo Seco steam plant. For perspective on the magnitude of the projected CIP for the five years ending in fiscal year 2014, which is $1,700 million, this amount is 17% less than the total actual CIP expenditures for the five year period ending in fiscal year 2004, without adjusting for inflation.

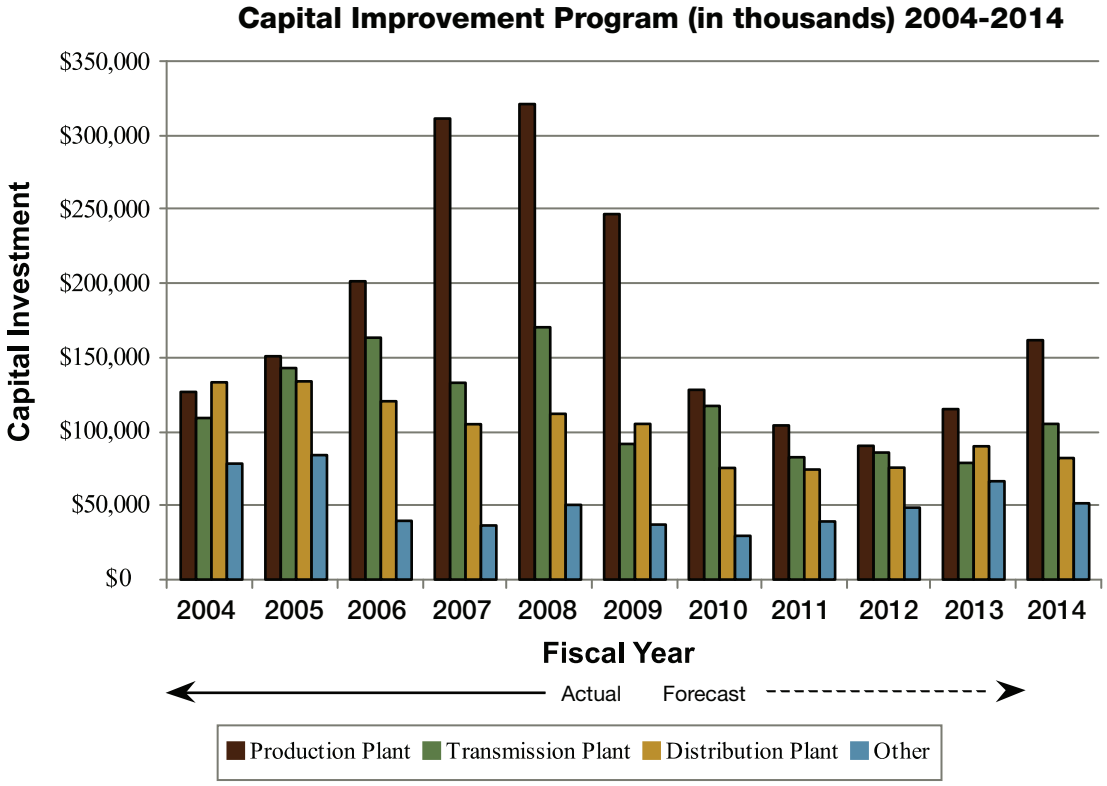
As shown in *Appendix II, Income Statement,* during fiscal year 2010 the Authority plans to make no contributions to the Capital Improvement Fund. Funding for the Capital Improvement Program is discussed further in *Capital Improvement Fund* section below.

Each year, the Consulting Engineers reviews the Authority's five-year Capital Improvement Program. We believe that the moneys shown in the CIP for extensions and improvements to the System over the forecast period are reasonable. We also approve the Annual Budget of Current Expenses and Capital Expenditures prior to the beginning of each fiscal year. The Annual Budget includes the expenditures for the first year of the CIP.

The CIP is comprised of numerous budget items grouped into five general categories. The largest expenditures are in production plant, transmission plant, and distribution plant. The chart below shows the trends and relative values of these groups over the five-year budget period.

PRODUCTION PLANT

The CIP for fiscal year 2010 includes $128.0 million for production plant related projects. These projects are grouped in two classifications: expansion projects—$12.5 million and rehabilitation projects—$115.5 million.



The final phase of the current production plant expansion program is the completion of civil and non-essential balance of plant work associated with the new replacement combustion turbines at the Mayagüez plant. Some of the balance of plant work associated with the new combustion turbine project had been constrained in fiscal year 2009 by erection sequencing.

The rehabilitation projects are the major refurbishment work planned for the Authority's operating production plants. A representative scope of these projects is discussed in the *Production Plant* section. For example, these activities include the work planned for the major overhauls at Aguirre Unit 1, Cost Sur Unit 6 and San Juan Unit 8. The projects at production plants include improvements to various major systems, such as the boiler, steam turbine-generator, combustion turbine, control systems, hydroelectric plant, and balance of plant systems. The Authority has identified projects within the rehabilitation category that are for pollution control, or for environmental issues, that have a total value of $10.3 million for fiscal year 2010. Environmental projects include air and water pollution control projects, new sanitary sewer construction at existing production plants, spill containment dikes around fuel oil storage tanks and spill prevention, control and countermeasures at Authority substations.

TRANSMISSION PLANT

The CIP for fiscal year 2010 includes $117.2 million for transmission plant related projects. Expansion projects are budgeted at $79.8 million and rehabilitation projects have a budget of $37.4 million.

The expansion projects are the new transmission lines, transmission centers, switchyards, high voltage equipment, and extensions at existing facilities to support the growth of the transmission system. The major planned projects for the 230, 115 and 38 kV systems are described in the *Transmission* section. These projects include the new 230 kV lines from Costa Sur to Cambalache and from Costa Sur to Aguas Buenas, the new 115 kV GIS transmission center at San Juan steam plant, the new 38 kV underground projects in various municipalities around the island, new 115/38 kV transmission centers at Hato Tejas and Las Cruces, and increasing the capacity of the existing Victoria and Canovanas transmission centers.

Improvements to the 230, 115 and 38 kV systems constitute the rehabilitation projects. These include replacement of structurally deteriorating lines and poles, especially in the 38 kV system, and the upgrading of the supervisory control and data acquisition (SCADA) system.

DISTRIBUTION PLANT

The distribution system CIP budget for fiscal year 2010 is $75.3 million and is comprised of $17.0 million for expansion projects and $58.0 million for rehabilitation projects.

The distribution expansion projects include new substations, including 13.2 kV substations at Factor, Yabucoa, Hato Tejas, and Rio Bayamón. The expansion projects also include new underground distribution lines, temporary substations and portable equipment, new 13.2 kV feeders, and work associated with service to new clients.

The rehabilitation projects to the distribution system include improvements to existing substations and line facilities, replacement of distribution poles and lines, and the improvement and/or extension of underground distribution lines; this scope includes the work in the historic district of Ponce. The largest budget item account in this category is directed to the purchase of automated meters. The balance of the distribution projects addresses numerous miscellaneous requirements such as the purchase and installation of breakers, sectionalizers, voltage regulators, capacitors, and similar distribution equipment and systems.

GENERAL PLANT

The fourth category within the CIP is the general plant which for fiscal year 2010 totals $24.2 million. This category is composed of $7.8 million for general land and buildings and $16.4 million for equipment.

General land and buildings includes moneys for the acquisition of land and rights of way and for structures. The land acquisition budget includes funds for new transmission line rights of way; it also includes land for future locations of photovoltaic arrays and wind turbines. Regarding structures and buildings, the general plant funds are for the construction of new and improvements to technical offices, buildings, warehouses and customer service facilities. These projects include the restoration of the Electric Service Center building in Monacillos.

The equipment group is made up of computer equipment at $5.4 million, transportation equipment (land and air) at $6.5 million, communications equipment at $1.0 million and other equipment at $3.5 million.

PRELIMINARY INVESTIGATIONS

The final category in the CIP is for preliminary studies and surveys. The fiscal year 2010 budget for these activities is $5.3 million. These studies are performed by the engineering, planning and environmental groups to support the evaluations of various system improvements and environmental compliance alternatives. Other studies evaluate improvements to the operation and maintenance of the transmission and distribution system.

FUNDING OF THE EMPLOYEE'S RETIREMENT SYSTEM

The Employee's Retirement System of the Authority is a separate trust fund created and administered by the Authority. The Retirement System is funded by contributions from both the Authority, based on annual actuarial valuations, and plan members. The Retirement System's independent actuary prepared an actuarial valuation dated September 17, 2009 for fiscal year 2008 and the results showed that the Retirement System's unfunded accrued liability had decreased from $825.6 million as of the end of fiscal year 2007 to $765.7 as of the end of fiscal year 2008.

The Authority's contribution rate was 21.1% in fiscal year 2007, 21.8% in fiscal year 2008, 21.1% in fiscal year 2009 and is anticipated to be 19.7% for the fiscal year ending June 30, 2010.

The following table summarizes the status of the Authority's Pension Plan for the year ending June 30, 2008:

AUTHORITY'S PENSION PLAN	
Plan Members Contribution Rate (Estimated based on member data for actuarial valuation)	10.1%
Annual Pension Cost (in thousands)	$76,290
Percentage of Annual Pension Cost Contributed	99.6%
Net Pension Obligation (in millions)	$13.5
Contributions made and accruals (in thousands)	$75,995
Based on the June 30, 2006 Actuarial:	
Value of Assets (in millions)	$1,571.2
Actuarial Accrued Liability	$2,336.9
Unfunded Actuarial Accrued Liability	$765.7
Funded Ratio	67.2%
Estimated Covered Payroll	$362.9
Unfunded Contribution Rate	13.7%

INVENTORIES AND OTHER PROPERTIES

The Material Management Division's mission is to support all of the Authority's installations with the material and equipment necessary to accomplish the Authority's goal of providing electric service to clients at the lowest possible cost. A part of the Administrative Services Directorate, the Authority's Material Management Division has two main subdivisions, which are Purchasing and Warehouses.

The Warehouses subdivision utilizes 34 warehouses and manages an extensive inventory worth in excess of $195.1 million of which $91.2 million is transmission and distribution material and $103.9 is related to its production plant spare inventory. The spare parts inventory for transmission and distribution plant includes the safekeeping of a number of items, such as transformers; poles; fuses, breakers; structures; and insulators. Among the items for production plant includes; spare rotors for units at the Aguirre and Costa Sur Steam Plants; and a spare turbine rotor for Palo Seco Units No. 3 & 4. For a (partial) list of spare components for the production plant refer to the *Spare Components* section in the *System's Operations* section.

FUNDING RECOMMENDATIONS

Section 706 of the 1974 Agreement reads in part:

> *it shall be the duty of the Consulting Engineers to include in such report [this Annual Report] their recommendations as to the amount that should be deposited monthly during the ensuing fiscal year to the credit of the Reserve Maintenance Fund…, deposited during the ensuing fiscal year to the credit of the Self-insurance Fund…and deposited during the ensuing fiscal year to the credit of the Capital Improvement Fund*

These three funds were created and funded in 1996 when the 1947 Trust Indenture was defeased.

There have been four major events that have caused losses to the Authority since the Reserve Maintenance and Self-insurance Funds were created.

The first was Hurricane Hortense in fiscal year 1997 that caused an estimated $36.0 million in damages to the Electric System. The entire loss of this event was borne by the Authority.

In fiscal year 1999 Hurricane Georges devastated the island. Total damages were estimated at $239.9 million of which $12.7 million was covered by insurance, $168.0 million was provided by the Federal Emergency Management Agency (FEMA) and the remainder of $59.2 million was the responsibility of the Authority.

Tropical Storm Jeanne in fiscal year 2005 caused an estimated $60 million in damages of which FEMA provided $11.8 million in aid and the balance of $42.8 million came from various funds of the Authority.

The most recent event was the fires at the Palo Seco Power Plant during fiscal year 2008. The total damages are estimated to be $363.2 million of which insurance payments to the end of fiscal year 2009 amounted to $301.3 million. Insured losses were still being negotiated at the end of the past fiscal year, leaving the Authority's share from $61.9 million and $33.8 million.

The specific utilization of money from the Reserve Maintenance and self-insurance Funds is discussed below.

RESERVE MAINTENANCE FUND

Section 512 of the 1974 Agreement reads in part:

> *moneys held for the credit of the Reserve Maintenance Fund shall be disbursed only for the purpose of paying the cost of unusual or extraordinary maintenance or repairs, maintenance or repairs not recurring annually and renewals and replacements, including major items of equipment.*

At the end of fiscal year 2009, the Reserve Maintenance Fund's balance was $5.6 million. The Reserve Maintenance Fund is a restricted fund in which the moneys are held in trust by the Authority.

Since the fund was created in 1996 there have been two instances when the Authority withdrew moneys from this fund.

The first instance occurred in fiscal year 2005, when $7.1 million was withdrawn and applied as part of the $45 million costs to repair the System following damages caused by Tropical Storm Jeanne. Additional sources of funds to restore the System came from FEMA and the Authority's Self-insurance Fund.

The second instance began in April 2007 when the Authority sought the Consulting Engineers' concurrence regarding the use of the Reserve Maintenance Fund as an interim source of funds for the recovery of the Palo Seco Steam Plant. The Consulting Engineers concurred, but stipulated that any moneys withdrawn from the Reserve Maintenance Fund should be replenished using the proceeds from the Authority's insurance program within a reasonable timeframe. Consistent with the Consulting Engineers intent, the Authority borrowed $9.4 million from the Reserve Maintenance Fund during fiscal year 2007 and $58.3 million during fiscal year 2008, a total of $67.7 million dollars. The withdrawals were carried as an inter-fund debt of the General Fund as part of the Palo Seco Steam Plant recovery project. During the same period the Authority returned $14.7 million from insurance proceeds, $5.0 million in fiscal year 2007 and $9.7 million in fiscal year 2008, netting a $53 million inter-fund debt of the General Fund to the Reserve Maintenance Fund.

Consistent with the Consulting Engineers responsibilities under the 1974 Trust Agreement, the Consulting Engineers recommended that the Authority deposit $5 million to the Reserve Maintenance Fund in fiscal year 2009. At the request of the Authority, the Consulting Engineers agreed that the monies would be added to the Reserve Maintenance Fund and concurrently reduce the $53 million inter-fund debt to approximately $48 million.

The Consulting Engineers recommend that the Authority deposit $5 million into the Reserve Maintenance Fund during fiscal year 2010.

SELF-INSURANCE FUND

Section 507 (g) of the 1974 Agreement reads in part:

> *to the credit of the Self-insurance Fund...such amount, if any, of any balance remaining after making the deposits under clauses (a), (b), (c), (d), (e), and (f) above, as the Consulting Engineers shall from time to time recommend; and*

Section 512A of the 1974 Agreement reads in part:

> *moneys held for the credit of the Self-insurance Fund (1) shall be disbursed...only for the purpose of paying the cost of repairing, replacing or reconstructing any property damaged or destroyed from or extraordinary expenses incurred as a result of a cause which is not covered by insurance…or (2) shall be transferred to the Revenue Fund in an amount, approved by the Consulting Engineers, equal to the loss of income from the System as a result of a cause which is not covered by insurance.*

Section 512A of the 1974 Agreement further reads:

> *If the Authority shall have determined that all or any portion of the moneys held to the credit of the Self-insurance Fund is no longer needed for the purposes specified in the second preceding paragraph, the Authority may withdraw an amount equal to such portion from the Self-insurance Fund and transfer such amount to the credit of the Bond Service Account; provided, however, that no such transfer shall be made prior to the time that the Consulting Engineers shall have approved such transfer in writing.*

As of the end of fiscal year 2009 the balance of the Self-insurance Fund was $62.6 million. Similar to the Reserve Maintenance Fund, the Self-insurance Fund is a restricted fund in which the moneys are held in trust by the Authority. The Authority has withdrawn moneys from this fund four times since its creation in 1996. The first withdrawal, in fiscal year 1997 for $32 million, was for damages caused by Hurricane Hortense. The second withdrawal for $30 million in fiscal year 1999 was for damages caused by Hurricane Georges. Then in fiscal year 2005 for damages caused by Tropical Storm Jeanne $18.3 million was withdrawn. It should be noted that these amounts were used to supplement insurance payments and reimbursements from FEMA. They represented only a fraction of the moneys required to restore the Authority's facilities.

In fiscal year 2007, at the request of the Authority, the Consulting Engineers authorized the withdrawal of moneys from the Self-insurance Fund to cover uninsured losses associated with the Palo Seco Steam Plant fires. During fiscal year 2008 the Authority withdrew $25.4 million from this fund for the uninsured losses associated with the Palo Seco Steam Plant fires. Also during fiscal year 2008 the Authority deposited $5.0 million to this fund. In fiscal year 2009 the Authority deposited $10 million to the fund in accordance with the Consulting Engineers recommendations.

For fiscal year 2010 the Consulting Engineers recommends that the Authority deposit $10 million to the Self-insurance Fund.

CAPITAL IMPROVEMENT FUND

Section 507 (h) of the 1974 Agreement reads in part:

> *to the credit of the Capital Improvement Fund such amount, if any, of any balance remaining after making the deposits under clauses (a), (b), (c), (d), (e), (f), and (g) above, as the Consulting Engineers shall recommend as provided by Section 706 of this Agreement; provided, however, that if the amount so deposited to the credit of said Fund during any fiscal year of the Authority shall be less than the amount recommended by the Consulting Engineers, the requirement therefore shall nevertheless be cumulative and the amount of any such deficiency in any such fiscal year shall be added to the amount otherwise required to be deposited in each fiscal year thereafter until such time as such deficiency shall have been made up, unless such requirement shall have been modified by the Consulting Engineers in writing, a signed copy of such modification to be filed with the Authority.*

Section 512B of the 1974 Agreement reads in part:

> *Moneys held for the credit of the Capital Improvement Fund shall be disbursed…only for paying the cost of anticipated extensions and Improvements of the System the cost of which has not otherwise been provided for from the proceeds of bonds issued under the provisions of this Agreement.*

The Consulting Engineers approves annually the Authority's budget for the ensuing fiscal year; the budget includes amounts for the first year of the five-year CIP. (For further discussion, refer to the *Annual Budget* in the *Financial* section) The Amended Budget for fiscal year 2009 projected that the Capital Improvement Program (CIP) expenditures would be $446.0 million, of which no monies would come from the Capital Improvement Fund. The actual CIP expenditures for fiscal year 2009,

however, totaled $480.2 million, of which $4.7 million was financed internally through the Capital Improvement Fund. For fiscal year 2010 the Capital Improvement Program is budgeted $350.0 million, of which no amount will come from internal funds. The internally generated funds portions of the CIP for fiscal years 2011 through 2014 are projected to be 7%, 3%, 1% and 0.4%, respectively.

The table below shows the Authority's actual deposits to the Capital Improvement Fund compared with that which was budgeted.

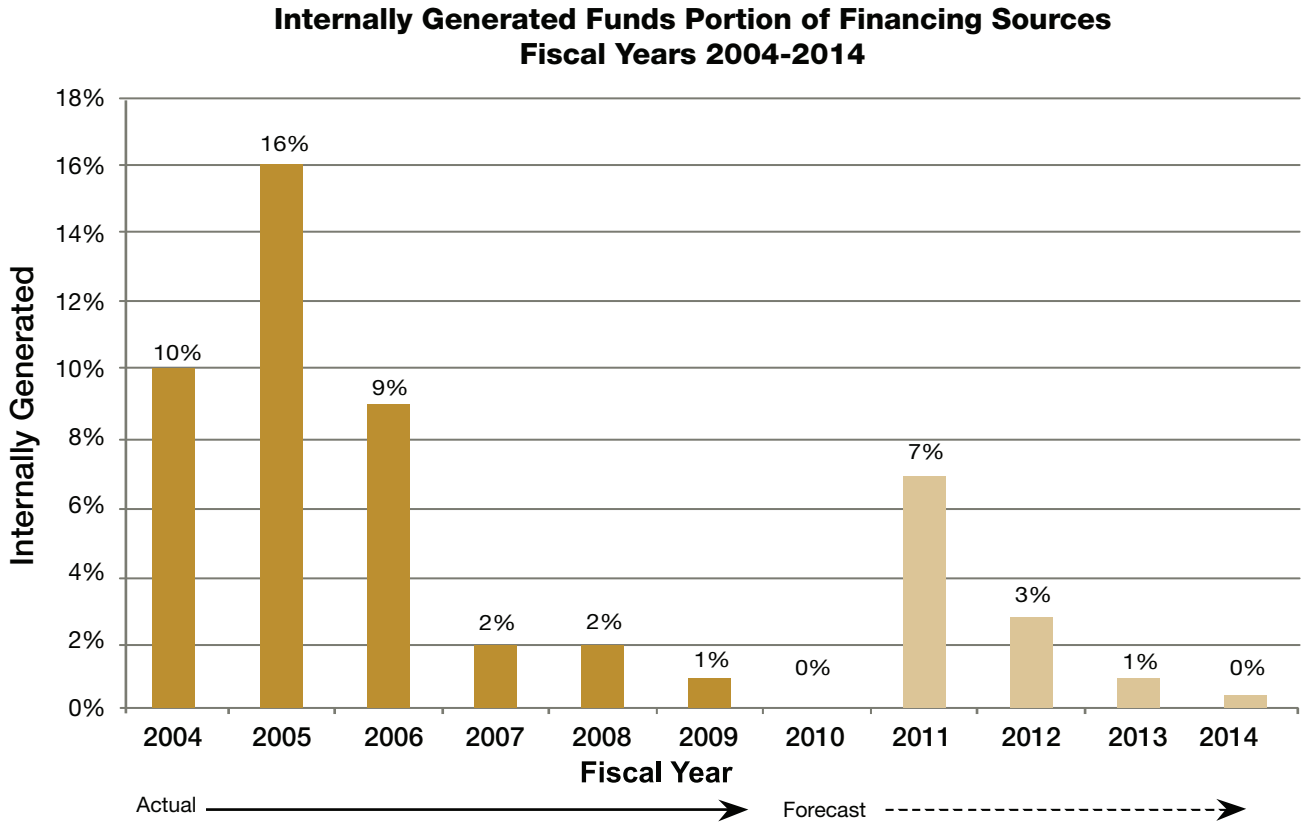
CAPITAL IMPROVEMENT FUND

Fiscal Year	Amount Budgeted	Amount Deposited	Difference
2009	$ 0.0	$ 4.7	$ 4.7
2008	$ 100.3	$ 6.6	($ 93.7)
2007	$ 69.6	$ 10.2	($ 59.4)
2006	$ 63.8	$ 49.6	($ 14.2)
2005	$ 77.4	$ 83.0	$ 5.6
2004	$ 96.7	$ 43.1	($ 53.6)

The level of deposits to the Capital Improvement Fund over the past five years was negatively impacted by overruns in discretionary budgets, the increased payments for Contributions in Lieu of Taxes, and the servicing of short-term financings required for working capital.

The Capital Improvement Fund also serves as an additional reserve for the payment of the principal of and the interest on the Power Revenue Bonds and meeting the amortization requirements to the extent that moneys in the 1974 Sinking Fund, including the 1974 Reserve Account, in the Reserve Maintenance Fund, and in the Self-insurance Fund are insufficient for such purpose.

The chart below shows the annual portions of internally generated funds for the total financing sources of capital expenditures since 2004 and those forecasted through 2014.



HUMAN CAPITAL

HUMAN RESOURCES

On June 30, 2009, the Authority had a total workforce of 9,216 employees: 9,184 permanent employees and 32 temporary employees or probationary employees who had been employed by the Authority for less than 12 months. The total number of employees on June 30, 2009 reflects a net decrease of 213 employees; 152 of whom were temporary employees who held entry level positions and 61 of whom were permanent employees. On June 30, 2008 the Authority had 9,429 employees, 9,245 of whom were permanent and 184 were temporary.

During March 2009 the Authority reduced the number of directorates from twelve to six. Three directorates, the Electric System, the Transmission & Distribution Directorate and the Engineering Directorate were consolidated into the Generation, Transmission & Distribution Directorate. The Client Services Directorate was merged with the Finance Directorate which was renamed the Finance & Client Services Directorate. The Communication and Community Relations and the Corporate Security Directorates were brought within the Executive Directorate. The Labor Affairs Directorate was realigned within the Human Resources Directorate. The Legal Directorate, Planning and Environmental Protection Directorate, and the Administrative Services Directorates maintained their directorate status. Ninety–two percent of the Authority's employees were employed in one of the following three directorates: 5,963 worked in the Generation, Transmission & Distribution Directorate or approximately 65% of the Authority's employees; the Finance & Client Services Directorate employed 1,794 persons or 19% of the Authority's workforce; and 750 employees were employed in the Administrative Services Directorate, approximately 8% of the Authority's workforce. An additional 709 persons were employed in one of the four other directorates or by the Governing Board.

The Authority prepares its employees for their job assignments by providing a wide range of training programs and refresher training programs. The Human Resources and Labor Affairs Directorate provides the Authority's employees with training in the areas of safety, health, computer usage and administrative skills. The training programs providing job specific, technical knowledge of the type needed by the employee to effectively perform their assigned work are provided by the directorate within which they are employed. Bargaining and non-bargaining unit employees, supervisors and managers participate in these programs.

The Authority is exploring actions that would reduce the impact on their operations of the escalating cost of the medical insurance coverage which they provide for employees and retirees.

LABOR AFFAIRS

The following paragraphs provide an overview of the bargaining units within the Authority and of the status of the labor agreements applicable to these bargaining units.

At the end of fiscal year 2009 four different unions represented 6,413 of the Authority's employees or 70% of the Authority's workforce. The other 2,803 employees are members of the executive, managerial, and administrative staff. The terms of employment for these 2,803 employees are not established by a collective bargaining agreement. The figures for fiscal year 2008 are similar; 6,576 employees represented by unions, (70% of the workforce), and 2,853 in executive, managerial, and administrative positions. In an effort to improve efficiency the Authority terminated 148 of its temporary employees during the last quarter of fiscal year 2009.

During fiscal year 2009 the Authority concluded the renegotiation of a contract with UTIER the largest of the four unions that represent certain of their employees. The results of this effort and the status of the collective bargaining agreements with the other three unions are described in the following paragraphs. Union and Authority representatives meet on a regular basis during the term of a collective bargaining agreement to discuss labor-management issues.

The Authority concluded the renegotiation of a collective bargaining agreement with the Electric Energy Authority's Pilot Union (UPAEE) in June 2006. The four-year agreement, which established wages, hours, and, conditions of employment for the Authority's six pilots, became effective on July 3, 2006 and will terminate on July 2, 2010. The pilots are scheduled to receive a 4% increase on July 3, 2009 for the final year of the agreement

The renegotiation of the agreement between the Authority and the Independent Professional Employees Union (UEPI), which represented 393 of the Authority's employees at the end of fiscal year 2009, was signed on February 13, 2008. The multi-

year agreement, which will terminate on December 13, 2010, established a 4% increase each December 14 during the term of the agreement.

In January 2008 the Authority completed the renegotiation of the current labor agreement with the Insular Union of Industrial and Electrical Construction Workers, (UTICE). The three-year agreement, which will terminate on January 26, 2011, called for an initial increase of 4% and for annual increases of 4%. UTICE represented 959 of the Authority's employees at the end of fiscal year 2009.

On August 28, 2008 the Authority and representatives of Union of Workers of Electrical Industry and Irrigation of Puerto Rico, (UTIER), signed a collective bargaining agreement that replaced the one that had terminated in November 2005. The parties had spent three years renegotiating the agreement. During the renegotiation of the agreement the union had called for several, brief and partial work stoppages, none of which caused the Authority's service to be interrupted. The current agreement remains in effect for four years, terminating on August 24, 2012. On June 30, 2009 UTIER represented 5,055 of the Authority's employees. The agreement calls for 4% wage increases each year on the anniversary date of the agreement. The agreement freezes the entry level pay rate for newly hired employees for the four-year term of the agreement. A labor management committee meets periodically to discuss matters of mutual interest.

EMPLOYEE SAFETY

Each of the Authority's directors is responsible to the Executive Director for the safety and health of the employees working within their respective directorate. Subordinate managers, supervisors, and ultimately the workers themselves share this responsibility. The Occupational Safety Division assigns the safety and health professionals and certain of the other resources needed to assist the directors in their efforts to prevent accidents and job-related illnesses. The Occupational Safety Division ensures that the Authority's workplace safety and health programs comply with relevant Federal and Commonwealth statutes and are consistent with the objectives of the Authority.

The Division's staff of 29 comprised largely of safety and health professionals provides assistance to managers and supervisors in the day-to-day implementation of safety and health programs. Thirteen of the 29 are assigned to other operating facilities and regional offices. The following is a sampling of the distribution of safety and health professionals across the island, there are eight Safety and Industrial Hygiene Officers, and five are assigned to generating stations, one each at: Central Aguirre Steam, Aguirre Combined Cycle, Central Costa Sur, Central Palo Seco, and Central San Juan. Two Safety and Industrial Hygiene Officers are based in Santurce and one is based in Monacillos; from the office locations they provide consulting services to the other directorates and to the Cambalache Power Plant. A Health and Safety Officer is assigned in each of the regional Transmission and Distribution offices in Arecibo, Carolina, Ponce, San Juan, Bayamon, Caguas, and Mayagüez. A Health and Safety Officer based in the Authority's Santurce office accepts assignments throughout the Commonwealth. The Authority has a single Safety Consultant responsible for the development and implementation of safety programs for the Authority's construction sites. The Hazard Communication Section provides training in hazardous waste operations and emergency response (HAZWOPER) to 300 empoyees and initial and refresher training in hazard recognition, personal protective equipment, and hazard communication at facilities throughout the Commonwealth to more than 3,000 of the Authority's employees each year.

Work-related illness and accident costs include medical care, workers compensation, salary continuation, fringe benefits, worker replacement, overtime, administrative costs, and other related expenses. Safety personnel provide a wide range of safety instruction programs; in addition to the hazard communication training noted above these include: confined space training, respirator use, ergonomics, energy lock out, hearing and eye protection, and emergency reporting. Much of the Authority's supervisory training focuses on the importance of conducting and recording job briefings so that subordinates fully understand the exposures that they might encounter in the course of completing a work assignment and the actions necessary to mitigate the exposures. Supervisory training programs increase the awareness of both the direct and indirect costs of accidents and illnesses, including their effect on the Authority's cost of doing business.

In calendar year 2008, the Authority reported to OSHA that its employees worked a total of

16,350,798 hours and sustained 1,507 incidents of work related injury or illness that were recordable in accordance with the OSHA's requirements. There were two fatalities. Both were the result of an electrical contact. The frequency with which the Authority's employees reported work-related injuries or illnesses in calendar year 2008 was 18.4, slightly higher than the frequency reported in calendar year 2007. This frequency continues to be more than four times the frequency rate experienced by mainland utilities in the same timeframe.

Six years ago legislation was enacted that for the first time made the Authority and other Puerto Rican public corporations subject to financial penalties, in the same manner as private corporations, for violations of OSHA regulations. The Authority's managers and supervisors were briefed on the change in the OSHA penalty provisions. In calendar year 2008, the Authority was cited seven separate times for violating OSHA regulations. The proposed penalty was ultimately dismissed in four of the seven instances; Authority ultimately paid $4,250 in settlement of the fines levied for the three other cited violations. This amount was less than half of the amount of the fines levied during the prior calendar year.

The employees of the Occupational Health Division, within the Human Resources Directorate, are responsible for providing first aid and medical treatment to employees from the reported onset of a work related injury or illness until the employee returns to work, is reassigned, or reclassified administratively. The initial interface is frequently at one of the eight dispensaries that are staffed with registered nurses and located at the Authority's main office in Santurce, in regional offices in Monacillos, Caguas, and Ponce. The other four dispensaries are located at the Aguirre, Costa Sur, Palo Seco, and San Juan steam electric plants. Employees were seen for initial treatment at these dispensaries more that 22,220 times, the majority of the time these treatments classified as for non-occupational conditions.

Following a work related injury or illness almost all employees are referred from the Authority's dispensary or a first aid facility to one of the Commonwealth's treatment clinics, which are a part of the Corporación del Fondo del Seguro del Estado (CFSE) or Fondo for short. The physicians and medical staff employed by Fondo provide the medical care required by the Authority's employees following a work related injury or illness and determine when the employee is capable of returning to work. A long-term goal of the Authority has been the reduction in the average number of workdays lost by their employees following a lost workday illness or incident. The cooperation of Fondo is critical to accomplishing this goal. During fiscal year 2007 the Authority was accepted into a Fondo program whereby Fondo committed to providing a coordinated interdisciplinary team of medical personnel to assist the Authority's employees to achieve the earliest return to work possible. The expectation is that by giving the Authority's employees priority status that the interval between appointments for follow-up care will be shortened enabling the injured or ill employee to return to work as soon as the required recuperation is complete. Throughout the year the Authority's representatives met with Fondo administrators to review the case management of employees being treated by Fondo. Other public entities also participate in this program.

The Authority uses a team of investigators to monitor cases for possible abuse of the Authority's employee accident leave policy. The Authority retains a physician to evaluate the fitness of an employee to return to work following a lost workday incident. When the evaluation has concluded that the employee is fit to return to work the Authority charges any subsequent time off against the employee's accrued vacation pending their return to work. Authority staff meets periodically with the staff of the clinics providing medical care to the Authority's employees in an effort to achieve the most expeditious provision of medical care for their employees. A separate section within this department manages the administrative issues associated with employees who are disabled.

Since 1995 the Authority has had a random drug-testing program, which has been implemented in steps. The random drug-testing program applies to approximately 5,800 employees in safety sensitive positions. During calendar year 2008 the Authority randomly tested 2,607 of the employees working in safety-sensitive positions; each were given two tests, 55 of them (2.1%) tested positive for illegal substances. The program provides for treatment and counseling for those individuals who test positive for drug use. An employee who tests positive for drugs three times may be terminated.

In 71.8% of the instances in which an employee sustained a work-related injury or illness the employee did not work on the day following the event. Twenty-eight percent of employees who sustained a work related injury or illness reported for work on the day following the onset of a work related illness or injury. Slightly more than half of those employees who reported for work on the day following the incident were reassigned to other duties or put on restricted duty. On average these employees were transferred or placed on restricted duty for 28 days. The ratio of injured or ill employees reporting for work the day after an injury or illness rather than staying home was the same as in the calendar year 2007. However, following a disabling incident, one that led to the employee's reassignment or rendered the employee unable to report for work, employees lost an average of 60 workdays, two more than the average number in calendar year 2007. For each quarter year during 2008 there were 416 employees recuperating at home due to a work related event. On average 336 employees had been released by Fondo to return to work while continuing to receive medical care at a Fondo facility; these employees were paid under the Authority's salary continuation plan for work time missed while receiving medical care.. Another 151 employees were using their accrued annual or sick leave to pay for time away from work while receiving medical care.

SUPPLEMENTARY INFORMATION

EXECUTIVE DIRECTOR CHANGE

On January 13, 2009 the Authority's Governing Board appointed Ing. Miguel A. Cordero López as Executive Director of the Authority, a position he held previously from 1993 to 2000. He replaced Ing. Juan F. Alicea Flores who had been named Executive Director in 2008.

Ing. Cordero is a professional electrical engineer with more than 30 years experience with the Authority. He served as the Director of the Transmission and Distribution prior to being appointed Executive Director in 1993. In addition to his service with the Authority, Ing. Cordero has served in management positions in many public sector agencies and Authorities. During Ing. Cordero's first tenure as Executive Director he initiated a major capacity expansion program and oversaw improvements to the existing generating plants. These programs brought cogenerators and fuel diversity to the System, lowered the cost of electricity and improved the quality of service.

PREPA SUBSIDIARIES

At the end of fiscal year 2009 the Authority owned four subsidiaries. The first (PREPA.Net) was created in 2005 for ownership of its fiberoptic network. Two other subsidiaries associated with power projects are discussed in *Alternative Energy Sources* in the *Capacity Planning* section. PREPA Oil & Gas was established to provide a mechanism for the Authority to participate in a wide range of commercial and operational projects for fuel supply and infrastructure. The Authority formed PREPA Renewables to expand the Authority's ability to participate in or assist in the development of renewable energy projects. The fourth subsidiary is PREPA Utilities which was formed to develop, construct and operate industrial projects and other related infrastructure to improve the electric infrastructure of the Authority.

In the year 2000 the Authority began the acquisition of a fiber optic cable system to modernize the Authority's internal communication systems and thereby provide faster and more secure data transmission for operations, load management, system protection, and security. In order to meet its optical fiber cable requirements, the Authority entered into a long-term agreement with Puerto Rico Information Networks, Inc. (PRIN) a private, independent, non-profit corporation incorporated in Puerto Rico.

Under the agreement, PRIN designed and built a fiber optic cable system that was installed on the Authority's rights-of-way (mainly its transmission lines). The fiber-optic cable is an integral part of the overhead ground wires which protect transmission lines from lightning strikes. When completed in August 2002, title to the system was transferred to the Authority.

The Authority financed its acquisition of the fiber optic system from PRIN by selling $43.7 million of Subordinate Obligations in October 2002. The agreement provided for the long-term lease to PRIN of any excess capacity for a 25-year period. Any resulting lease revenues, which were not be derived from the production and sale of electric energy, would be used to benefit the Authority's ratepayers.

In June 2005 the Authority created Prepa.Network Incorporated (PREPA.Net) to replace PRIN and market the excess communication capacity of the fiber optic network. Prepa.Net offers Next Generation Telecommunications (NGT) service to carriers, Internet Service Providers (ISP's), and large enterprises. The services include SONET, metro and long haul Ethernet transport services, wireless last mile, and Internet Protocol (IP) services optimized for Voice over Internet Protocol (VoIP) and other related services.

During fiscal year 2008 PREPA.net acquired Ultracom, one of three submarine cable firms on the island, to obtain international fiber optic cable capacity and satellite teleport facilities. The acquisition was financed with a term loan of $10.1 million.

PREPA.net's total assets at the end of fiscal year 2009 were $20.1 million and its net income was $2.1 million. In addition to the term loan, during fiscal year 2009 PREPA.Net had a revolving line of credit of $2 million for working capital.

LEGAL AFFAIRS

The Authority's Legal Affairs Directorate is responsible for a wide range of contract and litigation related activities. The following discussion summarizes the status of a number of the issues that the Authority litigated during fiscal year 2009.

The Authority contracted with Abengoa, Puerto Rico, S.E., as the primary contractor for the San Juan Units 5 & 6 repowering project. In May 2000, Abengoa unilaterally declared the construction contract terminated and filed a legal complaint for breach of contract against the Authority claiming approximately $18 million in damages. Subsequently, the Authority filed a counter claim for breach of contract and for damages in the amount of $200 million which they incurred as a result of the contract termination by Abengoa. In October 2007 the lawsuit was certified as complex litigation necessitating specialized treatment. The case was still in the discovery phase of technical matters phase at the end of fiscal year 2009. Early in fiscal year 2010 the parties will meet to discuss the use of arbitration to resolve their issues. As discussed in the *Production Plant* section, San Juan Units 5 & 6 went into commercial operation during the second quarter of the past fiscal year.

In June 2006 the Office of the Comptroller of Puerto Rico reported that the Authority overcharged its clients approximately $49.8 million between September 1999 and December 2003, and insisted that the Authority credit its customers that amount. Subsequent to the release of the Comptroller's report several additional suits were filed by various clients against the Authority seeking reimbursement for alleged overcharges; the total of all the claims is more than $700 million. The court ordered that all the plaintiff's cases regarding this matter be consolidated and ordered that the case be classified as complex litigation. The plaintiff's appeals were unsuccessful in requesting a class action determination. The Authority's holds that charges were determined correctly, in accordance with the established rates, and that these allegations are similar to ones in a previous lawsuit in which the Authority prevailed. At the close of fiscal year 2009 the case continued to make its way through the court system with little expectation of a speedy resolution.

As part of the settlement in 2007 of the litigation over the Contributions in Lieu of Taxes, CILT, the Authority agreed to perform certain infrastructure projects for the municipalities involved in the litigation. Among them was a multi-phased project for the Municipality of Ponce, a portion of which was to be paid for by the Municipality of Ponce. The Municipality became delinquent on $3 million due the Authority for phases one and two of the work. The Authority suspended work on the project and the Municipality sued the Authority in court. The matter was resolved in court, the Municipality paid the Authority the amount due and the Authority resumed work on the infrastructure project.

Three years ago the Authority filed suit in Puerto Rican Court against the Brazilian manufacturer and the manufacturer's Puerto Rico agent over the failure of the more than 6,000 batteries in the Sabana Llana

Battery Energy Storage System, BESS. The Authority is claiming damages of more than $18 million against the co-defendants; the case is entering its fourth year and continues in discovery.

During fiscal year 2008 the Authority awarded a contract to Skanska Energy Services, LLC (Skanska) to engineer, procure, and construct a 42 mile long gas pipeline from Guaynilla to the Authority's Aguirre Combined Cycle Plant. Early in fiscal year 2009 construction began with site development, environmental stabilization, and pipe fabrication. These activities continued until ordered stopped in early December 2008 by the Superior Court of Ponce following actions brought by southern communities in opposition to the gas pipeline. Skanska complied with the court ordered suspension and remained mobilized in anticipation of an order allowing construction to proceed. In response to the continuing opposition by certain communities the gas pipeline project was cancelled in April. Later that month the Commonwealth government announced a decision to utilize the former gas pipeline material to construct a water pipeline to transport water eastward from Guayanilla. The water pipeline would spur additional economic development in the southern half of the island. The Authority's efforts to transfer the pipeline project to the Aqueduct and Sewer Authority were continuing at the end of the fiscal year. Skanska inventoried materials and equipment and began demobilization while beginning negotiations with the Authority for recovery of compensation consistent with their contract with the Authority. At the end of fiscal year 2009 the Authority and Skanska were negotiating in an effort to reach a settlement of all matters related to the pipeline project. The Authority was also in discussion with the Commonwealth for the recovery of the project costs that followed from the decision to convert the gas pipeline to a water pipeline.

The Authority is making a concerted effort to significantly reduce the theft of electricity. Electricity theft is occurring across client classes and has been identified as having a material impact on the Authority's operations. During the last quarter of fiscal year 2009 the Authority identified more than 800 clients who had engaged in energy theft. At the end of the fiscal year these clients were being summoned to hearings before Administrative Law Judges who had the authority to make summary judgments regarding the theft and to assess fines. Through these proceedings the Authority collected approximately $100,000 in restitution during fiscal year 2009.

During the fiscal year the Authority closed more than 120 civil suits that had been brought against the Authority. The suits were settled for amounts between 10% and 12% of the damages claimed. These settlements were not material.

INSURANCE

The Risk Management Office, under the Finance Directorate, manages the Authority's Insurance Program. It is responsible for managing and controlling the Authority's resources to minimize risks of accidental losses. In addition, it analyzes, assesses, and recommends insurance policies and bonds for contracts and purchase orders. It settles property claims against the Authority valued at less than $10,000.

During fiscal year 2009 the Authority maintained a layered set of All Risk Property and Boiler and Machinery policies that provided a combined coverage of $750 million. The All Risk Property Policy provides coverage for business interruption, wind, flood, and earthquake; it excludes coverage of transmission and distribution lines other than underground lines, which is common in the electric utility industry. In addition to the two policies cited above the Authority's Insurance Program contains policies for Terrorism and Pollution, Builders Risk, Public Liability, Personal Auto Policy-Employees, Commercial Auto Policy-PREPA, Crime, Directors and Officers Liability, Fiduciary Liability, Aviation, Hull and Hull Risks, Owner Controlled Insurance Program (OCIP) Rolling Wrap-up, and Employment Practices Liability. The Authority holds a self-insured general retention of $2 million under its All Risk Property Policy for direct damage from all perils; the retention is $25 million under this policy for losses caused by natural events such as floods, wind, and earthquake. The business interruption coverage within the All Risk Property Policy is capped at $200 million with the Authority covering the costs from the first thirty days of the interruption. Property and Boiler and Machinery losses in excess of 300 million are covered by another policy that provides an additional $250 million in coverage. The public liability coverage remains at $75 million with the Authority holding $1 million retention, up to an annual aggregate of $2 million.

In May 2009 the Authority made a number of changes to their Insurance Program, these changes will be in effect during fiscal year 2010 and are as follows. Within the All Risk Property Policy the Authority's retention under the $550 million of

windstorm damage coverage is $50 million with a $25 million deductible per occurence up to an annual aggregate of $25 million. The pollution insurance formerly covered by the Terrorism and Pollution Policy remains unchanged at $250 million per pollution event with the Authority responsible for the retention of $300 million however the Authority has dropped insurance coverage for losses caused by terrorism. The deductible on the Authority's $550 million Boiler and Machinery Policy was increased from $10 million to $25 million per occurrence. Coverage under the Directors and Officers Liability Policy is $40 million. With the completion of major construction projects the Authority reduced Builders Risk Policy coverage to $35 million. The cost of the Authority's Insurance Program as renewed with these changes is approximately $19.1 Million.

The Authority has identified losses of $363.2 million that resulted from the fires at the Palo Seco Steam Plant on December 29 and 30 of 2006. The losses covered by the Boiler and Machinery Policy were estimated to be $16.9 million; the losses covered by the All Risk Property Policy due to fire damage were estimated to be $102.8 million. The Authority's estimate of Business Interruption losses, primarily fuel related, stood at $243.4 million. These excess fuel related costs were being processed for recovery. As of June 30, 2009 the Authority had been reimbursed a total of $301.3 million for losses associated with the two Palo Seco events; another $28.1 million was being negotiated.

The Tenth Supplemental Agreement created the Self-insurance Fund. This fund is to be used to pay for the cost of repairing, replacing, or reconstructing property damaged or destroyed from or extraordinary expenses incurred as a result of a cause that is not covered by insurance. It can also be used, when approved by the Consulting Engineers, to cover loss of income due to a cause, which is not covered by insurance. The monies in the Self Insurance Fund allow the Authority to increase its insurance deductibles thereby lowering its insurance premiums. Refer to the *Funding Recommendations* section for the Consulting Engineer's recommendation concerning the Self-insurance Fund.

The Eleventh Supplemental Agreement created the position of "Independent Consultant", a consultant or consulting firm or corporation to be employed by the Authority under Section 706 of this Agreement to carry out the duties of said Independent Consultant. Section 706 of the 1974 Agreement reads in part:

> *The Authority covenants and agrees…it will, for the purpose of carrying out the duties imposed on the Independent Consultant by this Agreement, employ one or more independent firms having a wide and favorable repute in the United States for expertise in risk management and other insurance matters related to the construction and operation of electric systems.*
>
> *It shall be the duty of the Independent Consultant to prepare and file with the Authority and the Trustee at least biennially, on or before the first day of November, beginning November, 1999, a report setting forth its recommendations, based on a review of the insurance then maintained by the Authority in accordance with Section 707 of this Agreement and the status of the Self-insurance Fund, of any changes in coverage, including its recommendations of policy limits and deductibles and self-insurance, and investment strategies for the Self-insurance Fund.*

An independent risk management consultant has been retained by the Authority in compliance with Section 707 of the Trust Agreement. The report of the Independent Consultant is scheduled for issuance in October 2009.

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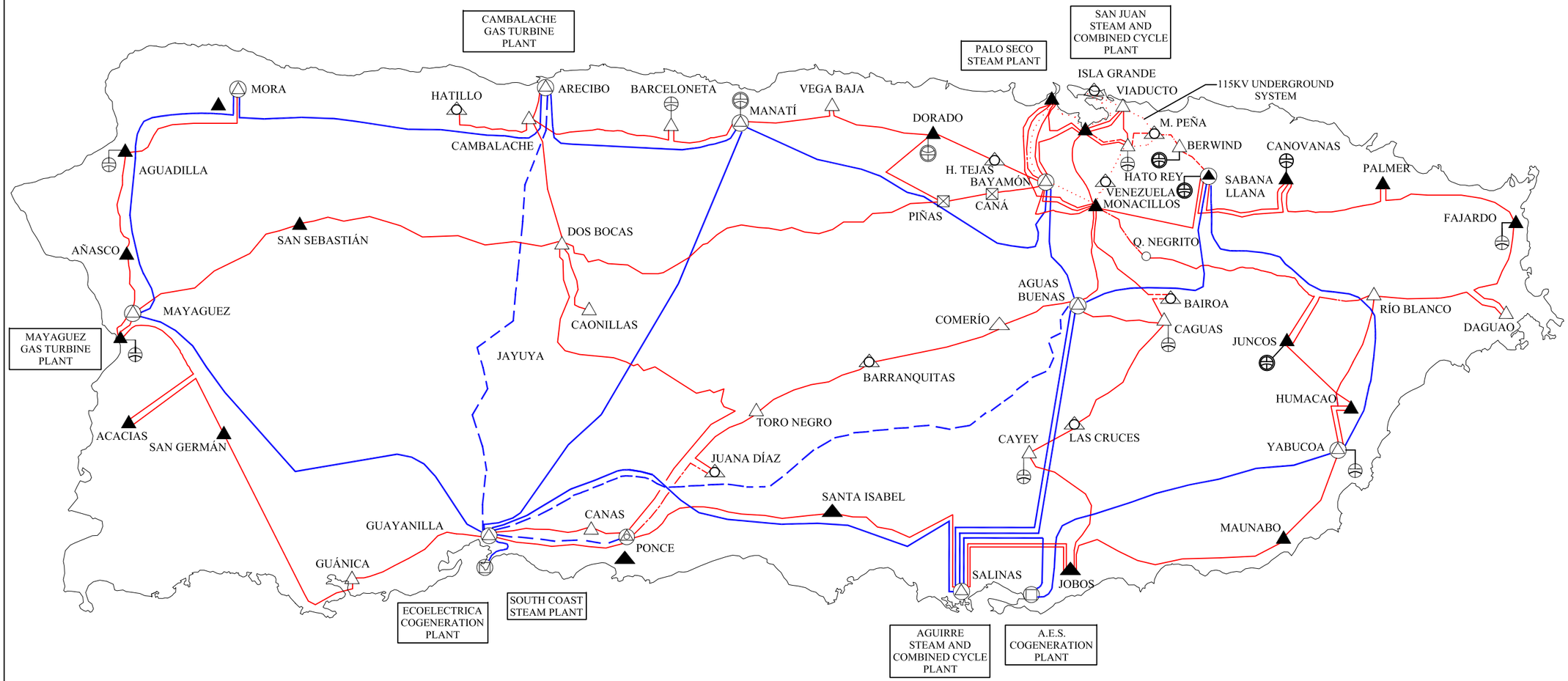
PREPA'S TRANSMISSION SYSTEM
2014



LEGEND:

230 KV LINE	230/115 KV TRANSFORMER
NEW 230 KV LINE	NEW 230/115 KV TRANSFORMER
RECONSTRUCTED 230 KV LINE	230/115 KV TRANSFORMER INCREASE CAPACITY
115 KV LINE	115/38 KV TRANSFORMER
NEW 115 KV LINE	NEW 115/38 KV TRANSFORMER
RECONSTRUCTED115 KV LINE	115/38 KV TRANSFORMER INCREASE CAPACITY
115 KV UNDERGROUND LINE	230 KV SWITCHYARD
115 KV CAPACITOR BANK	NEW 230 KV SWITCHYARD
NEW 115 KV CAPACITOR BANK	NEW 115 KV SWITCHYARD

PLANNED TRANSMISSION SYSTEM IMPROVEMENTS THRU FY 2014

After PREPA

APPENDICES

APPENDIX I
INTERMEDIATE-TERM FINANCIAL PLANNING FORECAST

	Actual[1]		Forecast									
	2009		2010		2011		2012		2013		2014	
	Amount	Increase %	Amount	Increase %	Amount	Increase %	Amount	Increase %	Amount	Increase %	Amount	Increase %
kWh SALES (000)												
Residential	6,367,561	(5.77)	6,038,349	(5.17)	5,859,889	(2.96)	5,722,924	(2.34)	5,633,381	(1.56)	5,587,448	(0.82)
Commercial	8,498,118	(2.81)	8,340,909	(1.85)	8,358,559	0.21	8,443,262	1.01	8,575,214	1.56	8,742,327	1.95
Industrial	3,288,597	(12.13)	3,188,314	(3.05)	3,159,331	(0.91)	3,138,422	(0.66)	3,130,438	(0.25)	3,135,603	0.16
Public Lighting	273,691	1.54	275,027	0.49	275,027	0.00	275,781	0.27	275,027	(0.27)	275,027	0.00
Agricultural	57,285	95.25	30,021	(47.59)	30,021	0.00	30,103	0.27	30,021	(0.27)	30,021	0.00
Others	30,523	(48.65)	56,421	84.85	56,421	0.00	56,575	0.27	56,421	(0.27)	56,421	0.00
TOTAL	18,515,775	(5.54)	17,929,041	(3.17)	17,739,248	(1.06)	17,667,067	(0.41)	17,700,502	0.19	17,826,847	0.71
CUSTOMERS (12 month average)												
Residential	1,324,752	0.78	1,327,116	0.18	1,329,026	0.14	1,330,943	0.14	1,332,853	0.14	1,334,759	0.14
Commercial	129,492	(0.40)	129,710	0.17	129,891	0.14	130,085	0.15	130,280	0.15	130,478	0.15
Industrial	898	(40.69)	865	(3.67)	830	(4.05)	796	(4.10)	762	(4.27)	727	(4.59)
Public Lighting	2,168	16.56	2,148	(0.92)	2,148	0.00	2,148	0.00	2,148	0.00	2,148	0.00
Agricultural	1,322	(3.29)	1,322	0.00	1,323	0.08	1,322	(0.08)	1,322	0.00	1,322	0.00
Others	4	(20.00)	4	0.00	4	0.00	4	0.00	4	0.00	4	0.00
TOTAL	1,458,636	0.65	1,461,165	0.17	1,463,222	0.14	1,465,298	0.14	1,467,369	0.14	1,469,438	0.14
kWh PER CUSTOMER												
Residential	4,807	(6.50)	4,550	(5.34)	4,409	(3.09)	4,300	(2.48)	4,227	(1.71)	4,186	(0.96)
Commercial	65,627	(2.42)	64,304	(2.01)	64,351	0.07	64,906	0.86	65,821	1.41	67,002	1.79
Industrial	3,662,135	48.15	3,685,912	0.65	3,804,768	3.22	3,942,603	3.62	4,109,834	4.24	4,310,930	4.89
Public Lighting	126,241	(12.89)	128,039	1.42	128,039	0.00	128,389	0.27	128,039	(0.27)	128,039	0.00
Agricultural	43,332	101.89	22,709	(47.59)	22,692	(0.08)	22,771	0.35	22,709	(0.27)	22,709	0.00
Others	14,321,250	20.47	13,541,040	(5.45)	13,540,967	(0.00)	13,578,065	0.27	13,540,967	(0.27)	13,540,967	0.00
BASE REVENUE ($000)												
Residential	$ 308,274	(6.51)	$ 290,405	(5.80)	$ 281,822	(2.96)	275,235	(2.34)	$ 270,928	(1.56)	$ 268,719	(0.82)
Commercial	569,484	(2.64)	562,120	(1.29)	563,309	0.21	569,018	1.01	577,911	1.56	589,173	1.95
Industrial	139,441	(14.06)	134,128	(3.81)	132,908	(0.91)	132,029	(0.66)	131,693	(0.25)	131,910	0.16
Public Lighting	50,556	0.85	50,704	0.29	50,704	0.00	50,842	0.27	50,704	(0.27)	50,704	0.00
Agricultural	2,582	60.87	1,588	(38.50)	1,588	0.00	1,593	0.31	1,588	(0.31)	1,588	0.00
Others	1,629	(43.00)	2,712	66.48	2,712	0.00	2,719	0.26	2,712	(0.26)	2,712	0.00
TOTAL	$1,071,966	(5.26)	$1,041,657	(2.83)	$ 1,033,043	(0.83)	$ 1,031,436	(0.16)	$ 1,035,536	0.40	$ 1,044,806	0.90
FUEL OIL ADJUSTMENT ($000)												
Residential	$ 791,686	(11.78)	$ 613,375	(22.52)	$ 709,393	15.65	$ 810,145	14.20	$ 844,418	4.23	$ 881,226	4.36
Commercial	983,819	(10.53)	800,282	(18.66)	955,239	19.36	1,128,336	18.12	1,213,436	7.54	1,301,620	7.27
Industrial	343,108	(20.04)	279,720	(18.47)	330,307	18.08	383,691	16.16	405,246	5.62	427,090	5.39
Public Lighting	33,026	(8.58)	27,949	(15.37)	33,272	19.05	39,013	17.25	41,197	5.60	43,347	5.22
Agricultural	3,922	(3.75)	3,175	(19.05)	3,634	14.46	4,261	17.25	4,500	5.61	4,735	5.22
Others	6,044	(12.07)	4,897	(18.98)	5,837	19.20	6,845	17.27	7,228	5.60	7,605	5.22
TOTAL	$ 2,161,605	(12.60)	$ 1,729,398	(19.99)	$ 2,037,682	17.83	$ 2,372,291	16.42	$ 2,516,025	6.06	$ 2,665,623	5.95
PURCHASED POWER ($000)												
Residential	$ 274,384	1.08	$ 282,848	3.08	$ 280,164	(0.95)	$ 282,053	0.67	$ 285,147	1.10	$ 270,344	(5.19)
Commercial	343,719	3.91	368,893	7.32	377,259	2.27	392,832	4.13	409,759	4.31	399,313	(2.55)
Industrial	119,436	(7.79)	128,957	7.97	130,450	1.16	133,304	2.19	136,560	2.44	130,751	(4.25)
Public Lighting	11,601	8.36	12,883	11.05	13,140	1.99	13,583	3.37	13,912	2.42	13,298	(4.41)
Agricultural	2,109	70.36	1,404	(33.43)	1,435	2.21	1,484	3.41	1,520	2.43	1,453	(4.41)
Others	1,361	(33.22)	2,261	66.13	2,305	1.95	2,383	3.38	2,441	2.43	2,333	(4.42)
TOTAL	$ 752,610	0.92	$ 797,246	5.93	$ 804,753	0.94	$ 825,639	2.60	$ 849,339	2.87	$ 817,492	(3.75)
REVENUES ($000)-incl. adj. charge												
Residential	$ 1,374,344	(8.29)	$ 1,186,628	(13.66)	$ 1,271,379	7.14	$ 1,367,433	7.56	$ 1,400,493	2.42	$ 1,420,289	1.41
Commercial	1,897,022	(5.87)	$ 1,731,295	(8.74)	$ 1,895,807	9.50	$ 2,090,186	10.25	$ 2,201,106	5.31	$ 2,290,106	4.04
Industrial	601,985	(16.50)	$ 542,805	(9.83)	$ 593,665	9.37	$ 649,024	9.32	$ 673,499	3.77	$ 689,751	2.41
Public Lighting	95,183	(1.84)	$ 91,536	(3.83)	$ 97,116	6.10	$ 103,438	6.51	$ 105,813	2.30	$ 107,349	1.45
Agricultural	8,613	24.50	$ 6,167	(28.40)	$ 6,657	7.95	$ 7,338	10.23	$ 7,608	3.68	$ 7,776	2.21
Others	9,034	(23.25)	$ 9,870	9.25	$ 10,854	9.97	$ 11,947	10.07	$ 12,381	3.63	$ 12,650	2.17
TOTAL	$ 3,986,181	(8.37)	$ 3,568,301	(10.48)	$ 3,875,478	8.61	$ 4,229,366	9.13	$ 4,400,900	4.06	$ 4,527,921	2.89

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APPENDIX II
INCOME STATEMENT

	Actual	Forecast				
	2009	2010	2011	2012	2013	2014
REVENUES						
Revenues from Appendix I	$ 3,986,180,000	$ 3,568,301,000	$ 3,875,478,000	$ 4,229,366,000	$ 4,400,900,000	$ 4,527,921,000
Add'l Revenues from Theft Recovery	-	16,955,000	50,000,000	50,000,000	50,000,000	50,000,000
From Sales of Electricity	3,986,180,000	3,585,256,000	3,925,478,000	4,279,366,000	4,450,900,000	4,577,921,000
From Commonwealth Government for Rural Electrification	19,000	-	-		-	-
Other Operating Revenue-Net	14,641,000	5,259,800	5,259,800	5,259,800	5,259,800	5,259,800
Total Operating Revenue	4,000,840,000	3,590,515,800	3,930,737,800	4,284,625,800	4,456,159,800	4,583,180,800
Other Income-Net	6,428,000	14,116,200	14,116,200	14,116,200	14,116,200	14,116,200
Total Revenues	$ 4,007,268,000	$ 3,604,632,000	$ 3,944,854,000	$ 4,298,742,000	$ 4,470,276,000	$ 4,597,297,000
CURRENT EXPENSES						
Operating Expenses	3,374,953,000	2,937,743,000	3,201,542,000	3,516,439,000	3,663,912,000	3,767,116,000
Miscellaneous Interest and Other	2,819,000	3,998,000	4,078,000	4,160,000	4,243,000	4,328,000
Total Current Expenses	3,377,772,000	2,941,741,000	3,205,620,000	3,520,599,000	3,668,155,000	3,771,444,000
Balance to Revenue Fund	629,496,000	662,891,000	739,234,000	778,143,000	802,121,000	825,853,000
1974 SINKING FUND						
Interest on Bonds	261,486,000	290,033,000	272,166,000	293,793,000	314,602,000	340,473,000
Bond Redemption	173,040,000	181,724,000	187,150,000	199,621,000	224,128,000	235,029,000
Reserve Account	(29,523,000)	-	-	-	-	-
Total Sinking Fund Payments	405,003,000	471,757,000	459,316,000	493,414,000	538,730,000	575,502,000
Balance	224,493,000	191,134,000	279,918,000	284,729,000	263,391,000	250,351,000
TRANSFERS						
Reserve Maintenance Fund[1]	-	5,000,000	5,000,000	5,000,000	-	-
Self Insurance Fund	10,000,000	10,000,000	10,000,000	10,000,000	-	-
1974 Capital Improvement Fund	4,695,000	-	20,204,000	7,912,000	2,705,000	1,419,000
Interest on Notes	28,434,000	17,938,000	16,249,000	15,834,000	15,578,000	15,360,000
Total	43,129,000	32,938,000	51,453,000	38,746,000	18,283,000	16,779,000
Balance	181,364,000	158,196,000	228,465,000	245,983,000	245,108,000	233,572,000
Contributions in Lieu of Taxes and Other	181,364,000	158,196,000	228,465,000	245,983,000	245,108,000	233,572,000
Balance	$ -	$ -	$ -	$ -	$ -	$ -

1. In lieu of a $5 million deposit to the Reserve Maintenance Fund in FY 2009, the Authority applied $5 million to partially repay funds borrowed by the General Fund as part of the Palo Seco Steam Plant recovery project.

APPENDIX III
DETAIL OF OPERATING and MAINTENANCE EXPENSES

	Actual[1]	Forecast				
	2009	2010	2011	2012	2013	2014
OPERATION						
Thermal and Gas Production						
Fuel Expense per PB projections						
Fuel	$ 1,919,788,752	$ 1,529,493,000	$ 1,803,904,000	$ 2,101,653,000	$ 2,229,579,000	$ 2,362,527,000
Purchased Power	671,848,891	711,701,000	715,987,000	734,818,000	755,910,000	727,567,000
Other Production Costs	59,894,465	54,939,459	51,288,000	51,161,280	51,045,120	50,939,520
Hydroelectric Plant Production	2,376,114	2,179,541	2,137,000	2,131,720	2,126,880	2,122,480
Transmission	24,039,346	21,709,550	18,829,800	18,783,300	18,740,700	18,702,000
Distribution	138,294,382	124,891,450	106,702,200	106,438,700	106,197,300	105,978,000
Client Accounting and Collection	111,126,317	112,674,000	101,349,000	101,098,000	100,868,000	100,660,000
Administrative and General	222,476,628	142,428,000	180,318,000	179,874,000	179,465,000	179,094,000
Interest Charge	2,819,366	3,998,000	4,078,000	4,160,000	4,243,000	4,328,000
Total Operation	$ 3,152,664,261	$ 2,704,014,000	$ 2,984,593,000	$ 3,300,118,000	$ 3,448,175,000	$ 3,551,918,000
MAINTENANCE						
Thermal and Gas Production	113,909,179	118,945,044	110,513,500	110,240,500	109,990,000	109,763,000
Hydroelectric Plant	3,417,593	3,568,683	4,420,540	4,409,620	4,399,600	4,390,520
Transmission	33,038,124	34,498,722	30,943,780	30,867,340	30,797,200	30,733,640
Distribution	67,346,556	70,323,911	66,308,100	66,144,300	65,994,000	65,857,800
General Plant	7,395,935	10,390,640	8,841,080	8,819,240	8,799,200	8,781,040
Total Maintenance	$ 225,107,387	$ 237,727,000	$ 221,027,000	$ 220,481,000	$ 219,980,000	$ 219,526,000
TOTAL O & M	$ 3,377,771,648	$ 2,941,741,000	$ 3,205,620,000	$ 3,520,599,000	$ 3,668,155,000	$ 3,771,444,000

1. Audited

APPENDIX IV
ANNUAL GENERATION, FUEL CONSUMPTION, AND FUEL COSTS FOR THERMAL STATIONS

	Actual 2009	Actual/Estimated[1] 2010	Forecast 2011	2012	2013	2014
AGUIRRE STEAM PLANT						
Net MWh-Generated	4,765,593	4,926,472	3,276,261	2,765,128	2,910,509	2,933,486
Barrels of Fuel Oil Used	7,729,140	7,834,882	5,238,786	4,456,958	4,701,381	4,695,051
MBTUx1000	48,694	49,352	32,980	28,052	29,587	29,557
kWh Per Barrel	617	629	625	620	619	625
Cost of Fuel	$ 547,551,636	$ 506,691,312	$ 412,479,035	$ 418,350,385	$ 467,730,974	$ 484,879,162
Cost of Fuel Per Barrel	$ 70.84	$ 64.67	$ 78.74	$ 93.86	$ 99.49	$ 103.27
$/Mbtu	$ 11.24	$ 10.27	$ 12.51	$ 14.91	$ 15.81	$ 16.40
COSTA SUR STEAM PLANT						
Net MWh-Generated	4,834,335	3,381,705	4,603,744	4,690,269	4,800,528	4,739,180
Barrels of Fuel Oil Used	8,231,663	5,759,583	7,748,089	7,880,785	8,064,999	7,973,443
MBTUx1000	51,859	36,285	48,813	49,649	50,809	50,233
kWh Per Barrel	587	587	594	595	595	594
Cost of Fuel	$ 545,698,574	$ 356,678,531	$ 590,457,689	$ 701,606,003	768,654,954	783,951,211
Cost of Fuel Per Barrel	$ 66.29	$ 61.93	$ 76.21	$ 89.03	$ 95.31	$ 98.32
$/Mbtu	$ 10.52	$ 9.83	$ 12.10	$ 14.13	$ 15.13	$ 15.61
PALO SECO STEAM PLANT						
Net MWh-Generated	1,315,773	2,847,157	2,931,018	2,926,045	2,854,253	2,425,156
Barrels of Fuel Oil Used	2,264,347	4,772,810	4,868,202	4,867,429	4,741,026	4,048,681
MBTUx1000	14,259	30,060	30,658	30,653	29,857	25,495
kWh Per Barrel	581	597	602	601	602	599
Cost of Fuel	$ 155,945,367	$ 298,320,705	$ 367,064,215	$ 434,372,192	452,785,608	400,341,426
Cost of Fuel Per Barrel	$ 68.87	$ 62.50	$ 75.40	$ 89.24	$ 95.50	$ 98.88
$/Mbtu	$ 10.94	$ 9.92	$ 11.97	$ 14.17	$ 15.17	$ 15.70
SAN JUAN STEAM PLANT						
Net MWh-Generated	2,081,798	1,036,677	412,017	427,968	250,496	604,376
Barrels of Fuel Oil Used	3,344,359	1,906,971	767,555	802,498	473,232	1,131,457
MBTUx1000	21,069	12,014	4,836	5,056	2,981	7,128
kWh Per Barrel	622	544	537	533	529	534
Cost of Fuel	$ 223,923,934	$ 118,274,012	$ 55,257,857	$ 71,927,960	44,945,122	111,281,050
Cost of Fuel Per Barrel	$ 66.96	$ 62.02	$ 71.99	$ 89.63	$ 94.97	$ 98.35
$/Mbtu	$ 10.63	$ 9.84	$ 11.43	$ 14.23	$ 15.08	$ 15.61
AGUIRRE COMBINED-CYCLE UNITS						
Net MWh-Generated	465,777	123,730	420,327	298,103	314,397	451,885
Barrels of Fuel Oil or Equivalent	928,633	222,764	729,625	522,503	547,409	784,852
MBTUx1000	5,850	1,293	4,234	3,032	3,177	4,555
kWh Per Barrel (or equivalent)	502	555	576	571	574	576
Cost of Fuel	$ 139,492,982	$ 20,115,481	$ 74,629,270	$ 60,854,018	67,898,602	101,991,428
Cost of Fuel Per Barrel	$ 150.21	$ 90.30	$ 102.28	$ 116.47	$ 124.04	$ 129.95
$/Mbtu	$ 23.84	$ 15.56	$ 17.62	$ 20.07	$ 21.37	$ 22.39
COMBUSTION-TURBINES & DIESELS						
Net MWh-Generated	102,715	110,406	45,866	89,818	36,759	59,175
Barrels of Fuel Oil Used	216,634	265,807	114,955	223,480	92,313	147,989
MBTUx1000	1,257	1,542	667	1,297	536	859
kWh Per Barrel	474	415	399	402	398	400
Cost of Fuel	$ 33,732,686	$ 23,729,793	$ 11,839,591	$ 26,157,348	11,397,470	19,166,420
Cost of Fuel Per Barrel	$ 155.71	$ 89.27	$ 102.99	$ 117.05	$ 123.47	$ 129.51
$/Mbtu	$ 26.83	$ 15.38	$ 17.75	$ 20.17	$ 21.28	$ 22.32
CAMBALACHE						
Net MWh-Generated	326,140	238,916	122,407	177,784	100,714	139,953
Barrels of Fuel Oil or Equivalent	665,976	493,435	255,406	374,889	210,285	292,132
MBTUx1000	3,865	2,863	1,482	2,175	1,220	1,695
kWh Per Barrel	490	484	479	474	479	479
Cost of Fuel[2]	$ 90,247,850	$ 45,051,703	$ 27,486,452	$ 45,995,404	27,227,452	39,638,372
Cost of Fuel Per Barrel	$ 135.51	$ 91.30	$ 107.62	$ 122.69	$ 129.48	$ 135.69
$/Mbtu	$ 23.35	$ 15.73	$ 18.55	$ 21.14	$ 22.31	$ 23.38
MAYAGUEZ TURBINES						
Net MWh-Generated	124,451	449,959	586,853	534,392	476,897	644,522
Barrels of Fuel Oil or Equivalent	193,024	768,418	985,291	896,869	800,458	1,081,923
MBTUx1000	1,120	4,457	5,715	5,202	4,643	6,275
kWh Per Barrel	645	586	596	596	596	596
Cost of Fuel	22,934,567	64,361,370	$ 92,802,169	$ 95,371,988	90,777,462	128,350,665
Cost of Fuel Per Barrel	$ 118.82	$ 68.64	$ 79.41	$ 106.34	$ 113.41	$ 118.63
$/Mbtu	$ 20.48	$ 14.44	$ 16.24	$ 18.33	$ 19.55	$ 20.45
REPOWERED SAN JUAN UNITS. 5 & 6						
Net MWh-Generated	913,442	932,642	1,338,252	1,752,371	1,961,659	1,856,778
Barrels of Fuel Oil or Equivalent	1,609,918	1,294,606	1,846,199	2,418,324	2,703,816	2,561,079
MBTUx1000	9,342	7,509	10,708	14,026	15,682	14,854
kWh Per Barrel	567	720	725	725	726	725
Cost of Fuel	160,261,158	105,573,173	$ 180,908,959	$ 255,994,919	307,094,737	302,013,407
Cost of Fuel Per Barrel	$ 99.55	$ 81.55	$ 97.99	$ 105.86	$ 113.58	$ 117.92
$/Mbtu	$ 17.15	$ 14.06	$ 16.89	$ 18.25	$ 19.58	$ 20.33
TOTAL THERMAL						
Net MWh-Generated	14,930,024	14,047,664	13,736,745	13,661,878	13,706,212	13,854,511
Barrels of Fuel Oil	25,183,694	23,319,276	22,554,108	22,443,735	22,334,919	22,716,607
MBTUx1000	157,315	145,375	140,092	139,142	138,492	140,652
kWh Per Barrel	593	602	609	609	614	610
Fuel Cost	$ 1,919,788,754	$ 1,538,796,080	$ 1,812,925,237	$ 2,110,630,217	$ 2,238,512,381	$ 2,371,613,141
Cost of Fuel Per Barrel	$ 76.23	$ 65.99	$ 80.38	$ 94.04	$ 100.22	$ 104.40
$/Mbtu	$ 12.20	$ 10.59	$ 12.94	$ 15.17	$ 16.16	$ 16.86
PURCHASED POWER-ECOELECTRICA						
Net MWh-Generated	3,290,550	3,622,402	3,550,905	3,561,228	3,550,905	3,550,906
Cost	$ 414,989,328	$ 428,737,961	$ 431,195,327	$ 446,218,721	$ 462,015,315	$ 484,480,218
$/MWH	$ 126.12	$ 118.36	$ 121.43	$ 125.30	$ 130.11	$ 136.44
PURCHASED POWER-AES						
Net MWh-Generated	3,373,152	3,446,996	3,377,488	3,357,532	3,362,521	3,362,521
Cost	$ 256,859,563	$ 282,962,569	$ 284,791,505	$ 288,599,707	$ 293,894,665	$ 243,086,490
$/MWH	$ 76.15	$ 82.09	$ 84.32	$ 85.96	$ 87.40	$ 72.29
PURCHASED POWER						
Net MWh-Generated	6,663,702	7,069,398	6,928,393	6,918,760	6,913,426	6,913,427
Cost	$ 671,848,891	$ 711,700,530	$ 715,986,832	$ 734,818,428	$ 755,909,980	$ 727,566,708
$/MWH	$ 100.82	$ 100.67	$ 103.34	$ 106.21	$ 109.34	$ 105.24
TOTAL (Including Purchased Power)						
Net MWh-Generated	21,593,726	21,117,062	20,665,138	20,580,638	20,619,638	20,767,938
Cost	$ 2,591,637,645	$ 2,250,496,610	$ 2,528,912,069	$ 2,845,448,645	$ 2,994,422,361	$ 3,099,179,849
$/MWH	$ 120.02	$ 106.57	$ 122.38	$ 138.26	$ 145.22	$ 149.23
HYDROELECTRIC						
Net MWh-Generated	169,463	107,116	126,170	126,170	126,170	126,170
TOTAL (Including Hydro & PP)						
Net MWh-Generated	21,763,189	21,224,178	20,791,308	20,706,808	20,745,808	20,894,108
Cost	$ 2,591,637,645	$ 2,250,496,610	$ 2,528,912,069	$ 2,845,448,645	$ 2,994,422,361	$ 3,099,179,849

1. FY 2010 consists of 3 months actual, 9 months estimated

Cost of fuel includes shipping and handling charges
Future generation based on Current Forecast

APPENDIX V
DEBT SERVICE COVERAGE UNDER THE 1974 TRUST AGREEMENT

Date of Issue	Series	Principal Amount After Payments and Refunding	Maximum Principal & Interest	Adjusted Net Revenues: 12 Consecutive Months Preceding Date of Issue	Adjusted Net Revenues: Percent Coverage	Average Net Revenues: 5 Years Following Current Year	Average Net Revenues: Percent Coverage
7/1/1993	REA-I	26,631,000	240,632,252	367,577,000	152.75	447,586,000	186.00
4/1/1994	S (Refunding)	31,440,000 [1]	267,390,756	421,241,000	157.54	491,034,600	183.64
5/1/1997	AA	50,555,000 [2]	319,985,410	448,850,000	140.27	573,065,000	179.09
5/1/1997	BB (Refunding)	51,285,000 [3]	319,985,410	448,850,000	140.27	573,065,000	179.09
7/1/1997	CC (Refunding)	88,450,000	319,099,985	448,850,000	140.66	573,065,000	179.59
3/15/1998	DD	93,585,000 [4]	360,810,198	509,343,000	141.17	611,400,000	169.45
3/15/1998	EE (Refunding)	325,645,000 [5]	360,810,198	509,343,000	141.17	611,400,000	169.45
9/1/1998	GG (Refunding)	93,280,000 [6]	349,986,029	552,061,000	157.74	652,800,000	186.52
4/6/1999	FF (Refunding)	96,175,000 [7]	347,959,070	520,905,000	149.70	681,738,800	195.92
8/1/2000	HH	39,905,000 [8]	390,015,290	565,528,000	145.00	703,124,400	180.28
1/3/2002	II	21,345,000 [9]	415,641,309	636,368,000	153.11	746,303,000	179.55
1/3/2002	JJ (Refunding)	179,580,000	415,641,309	636,368,000	153.11	746,303,000	179.55
7/2/2002	KK (Refunding)	384,970,000 [10]	415,923,000	627,086,000	150.77	746,303,000	179.43
7/2/2002	LL	98,125,000	415,923,000	627,086,000	150.77	746,303,000	179.43
10/3/2002	MM (Refunding)	65,415,000 [11]	415,918,000	630,219,000	151.52	746,303,000	179.44
8/19/2003	NN	171,525,000 [12]	442,399,978	664,780,000	150.27	728,160,000	164.59
8/26/2004	OO (Refunding)	128,830,000	442,395,314	635,751,000	143.71	711,111,000	160.74
8/26/2004	PP (Refunding)	86,800,000	442,395,314	635,751,000	143.71	711,111,000	160.74
4/4/2005	QQ (Refunding)	95,270,000	473,784,011	612,777,000	129.34	711,111,000	150.09
4/4/2005	RR	236,265,000 [13]	473,784,011	612,777,000	129.34	711,111,000	150.09
4/4/2005	SS (Refunding)	467,295,000	473,784,011	612,777,000	129.34	711,111,000	150.09
5/3/2007	TT	643,530,000	455,022,444	698,001,000	153.40	723,100,000	158.92
5/3/2007	UU	1,300,035,000	455,022,444	698,001,000	153.40	723,100,000	158.92
5/30/2007	V V (Refunding)	557,410,000	455,022,444	698,001,000	153.40	723,100,000	158.92
6/26/2008	WW	697,345,000	476,874,792	662,928,000	139.02	756,405,000	158.62

The total debt issued under the Trust Agreement is $14,027,733,431 which includes refundings totaling $7,778,311,431.
As of June 30, 2009 the outstanding debt under the 1974 Trust Agreement is $6,030,691,000.

The superscripted Principal Amounts in the table reflect the effects of refundings described below:

1. $4,760,000 refunded by Series OO and deducted from the original $163,875,000 Series S issue.
2. $62,335,000 refunded by Series UU; $5,450,000 refunded by Series QQ, $269,615,000 refunded by Series SS and deducted from the original $464,840,000 Series AA issue.
3. $30,285,000 refunded by Series SS and deducted from the original $100,750,000 Series BB issue.
4. $39,770,000 refudned by Series V V; $278,710,000 refunded by Series UU; $10,220,000 refunded by Series OO and deducted from the original $508,555,000 Series DD issue.
5. $2,740,000 refunded by Series SS and deducted from the original $380,515,000 Series EE issue.
6. $5,875,000 refunded by Series SS and deducted from the original $109,695,000 Series GG issue.
7. $24,035,000 refunded by Series UU and deducted from original issue $196,825,000 Series FF issue.
8. $342,180,000 refunded by Series UU; $108,300,000 refunded by Series JJ; $10,435,000 refunded by Series KK; $11,335,000 refunded by Series OO; $63,210,000 refunded by Series SS and deducted from the original $612,240,000 Series HH issue.
9. $493,960,000 refunded by Series UU and deducted from the original $515,305,000 Series II issue.
10. $7,765,000 refunded by Series SS and deducted from the original $401,785,000 Series KK issue.
11. $11,000,000 refunded by Series SS and deducted from the original $105,055,000 Series MM issue.
12. $288,590,000 refunded by Series V V; $57,190,000 refunded by Series UU and deducted from original amount $517,305,000 Series NN issue.
13. $273,255,000 refunded by Series V V and deducted from original amount $509,520,000 Series RR issue.

APPENDIX VI

CAPITAL EXPENDITURES

	Actual[1]	Forecasted				
	2009	2010	2011	2012	2013	2014
Production Plant	$ 246,578,000	$ 128,014,000	$ 104,005,000	$ 90,250,000	$ 115,001,000	$ 161,500,000
Transmission Plant	91,508,000	117,151,000	82,537,000	85,697,000	78,715,000	105,032,000
Distribution Plant	105,028,000	75,322,000	74,246,000	75,519,000	89,937,000	81,998,000
General Land and Buildings	22,345,000	7,826,000	8,981,000	12,551,000	27,286,000	18,426,000
General Equipment	15,191,000	16,412,000	26,215,000	31,491,000	32,296,000	27,039,000
Preliminary Surveys and Investigations	(436,000)	5,275,000	4,016,000	4,492,000	6,765,000	6,005,000
Provision for incidental and Emergency Work	-	-	-	-	-	-
SUBTOTAL	$480,214,000	$350,000,000	$300,000,000	$300,000,000	$350,000,000	$400,000,000
Construction Costs in Previous Year Reimbursed in Current Year	80,480,000	101,849,000	104,226,000	105,476,000	106,226,000	89,726,000
Construction Costs in Current Year to be Reimbursed Next Year	(101,849,000)	(104,226,000)	(105,476,000)	(106,226,000)	(89,726,000)	(84,976,000)
TOTAL FUNDS REQUIRED	$ 458,845,000	$ 347,623,000	$ 298,750,000	$ 299,250,000	$ 366,500,000	$ 404,750,000

1. Audited

APPENDIX VII
SOURCES OF FUNDS FOR CAPITAL EXPENDITURES

	Actual[1]	Forecast				
	2009	2010	2011	2012	2013	2014
FUNDS FROM BOND ISSUES AND NOTES						
REVENUE BONDS[2]						
Balance in Fund Start of Fiscal Year	$ 567,265,000	$ 15,805,000	$ 163,004,000	$ 92,352,000	$ 108,223,000	$ 29,815,000
$1,030.9M Series "XX" Jan '10		1,000,000,000				
$618.6M Series "YY" Jul '11			-	600,000,000		
$670.1M Series "ZZ" Jul '13				-		650,000,000
Balance in Fund End of Fiscal Year	(15,805,000)	(163,004,000)	(92,352,000)	(108,223,000)	(29,815,000)	(67,028,000)
PAID FROM REVENUE AND REA BONDS	$ 551,460,000	$ 852,801,000	$ 70,652,000	$ 584,129,000	$ 78,408,000	$ 612,787,000
NOTES						
Notes Paid	(211,906,000)	(705,000,000)	-	(250,000,000)	-	(300,000,000)
Notes Issued-Regular Financing	98,000,000	200,000,000	250,000,000	-	300,000,000	100,000,000
PAID FROM NOTES	$ (113,906,000)	$ (505,000,000)	$ 250,000,000	$ (250,000,000)	$ 300,000,000	$ (200,000,000)
FUNDS FROM OTHER SOURCES						
Transfers from General Fund (Net)[3]	(401,000)	(30,928,000)	(41,652,000)	(60,129,000)	(34,408,000)	(38,787,000)
Interest earned on Construction Fund	4,165,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000
Capitalized Interest on Sinking Fund	18,530,000	24,750,000	13,750,000	19,250,000	16,500,000	24,750,000
Grants and other (Principally From FEMA)	(1,003,000)	-	-	-	-	-
PAID FROM OTHER SOURCES	21,291,000	(178,000)	(21,902,000)	(34,879,000)	(11,908,000)	(8,037,000)
GRAND TOTAL	$ 458,845,000	$ 347,623,000	$ 298,750,000	$ 299,250,000	$ 366,500,000	$ 404,750,000

1. Audited
2. Net proceeds from the bond issues
3. Capital Improvement Funds net of capitalized interest transferred to the General Fund.

APPENDIX VIII
SYSTEM CAPABILITY
MW OF GENERATING CAPACITY AT THE END OF THE FISCAL YEAR

	Actual	Forecasted Additions and Retirements				
	2009	2010	2011	2012	2013	2014
STEAM-ELECTRIC UNITS						
Aguirre	900	-	-	-	-	-
Costa Sur	990	-	-	-	-	-
CS Unit 3					(85.0)	-
Palo Seco	602					
San Juan	400	-	-	-	-	-
Total	2,892	-	-	-	(85.0)	-
COMBUSTION-TURBINE UNITS						
Aguirre	42	-	-	-	-	-
Cambalache	248	-	-	-	-	-
Costa Sur	42	-	-	-	-	-
Mayaguez	84	-	-	-	-	-
Units 3-1 & 3-2, 4-1 & 4-2	(84)					
Palo Seco	126	-	-	-	-	-
Other	168	-	-	-	-	-
Total	626	-	-	-	-	-
NEW POWER PLANT						
Repowering (San Juan Units No. 5 & 6)	464	-	-	-	-	-
New Mayaguez Combustion Turbines	220	-	-			
Cambalache Conversion to Combined-Cycle	-	-	-	-	-	-
Non-System Sources						
Cogenerators (Net)	961	-	-	-	-	-
Small Power Producer[1]	-	-	-	-	-	-
COMBINED-CYCLE UNITS						
Aguirre	592	-	-	-	-	-
DIESEL UNITS						
Culebra & Vieques	9	-	-	-	-	-
HYDROELECTRIC CAPACITY (Total)	100	-	-	-	-	-
EXISTING CAPACITY (End of Previous Fiscal Year)	5,264	5,864	5,864	5,864	5,864	5,779
CAPACITY INSTALLED	684	-	-	-	-	-
CAPACITY RETIRED	(84)	-	-	-	(85)	-
CUMULATIVE TOTAL CAPACITY (MW)	5,864	5,864	5,864	5,864	5,779	5,779
Less: PEAK LOAD (MW)*	3,351	3,223	3,190	3,175	3,206	3,248
RESERVE CAPACITY (MW)	2,513	2,641	2,674	2,689	2,573	2,531
RESERVE MARGIN (%)	75.0	81.9	83.8	84.7	80.3	77.9

* Peak load forecast from IAU-GI projection

1. PREPA has Power Purchase Agreements (PPA) with developers of 3 wind energy projects of 39 MW, 40 MW and 50 MW and a 50 MW waste-to-energy facility
   None of these small projects completed permitting in fiscal year 2009

APPENDIX IX
DEPRECIATION EXPENSE

	Actual[1]	Forecasted				
	2009	2010	2011	2012	2013	2014
DEPRECIATION						
Steam Production Plant	$ 49,815,454	$ 56,635,012	$ 58,120,001	$ 59,604,990	$ 61,089,980	$ 62,574,969
Gas-turbine Production Plant	34,926,379	39,707,676	40,748,824	41,789,973	42,831,122	43,872,270
Hydroelectric Production Plant	1,445,957	1,643,903	1,687,007	1,730,111	1,773,214	1,816,318
Transmission Plant	45,562,852	51,800,243	53,158,463	54,516,683	55,874,902	57,233,122
Distribution Plant	120,190,620	136,644,287	140,227,147	143,810,006	147,392,866	150,975,726
General Plant[2]	52,527,571	56,813,879	58,303,558	59,793,237	61,282,916	62,772,595
Total Depreciation Expense	304,468,833	343,245,000	352,245,000	361,245,000	370,245,000	379,245,000

1. Audited
2. Includes clearing accounts

APPENDIX X
DETAILS OF CAPITAL IMPROVEMENT PROGRAM

Budget Item Number		Estimated Expenditures by Fiscal Year 2010	2011	2012	2013	2014
PRODUCTION PLANT						
	THERMAL PRODUCTION PLANT					
100	New Generation	$ 12,453,000	$ -	$ -	$ -	$ -
120	Auxiliary Electric Components	-	390,000	-	600,000	-
150	Fuel Hanlding and Storage Infrastructure	-	-	-	100,000	-
160	Boiler Improvements	21,300,000	5,825,000	10,200,000	7,850,000	15,400,000
165	Improvements to Steam Turbines and Generators	21,625,000	22,350,000	17,500,000	8,450,000	17,750,000
170	Improvements to Balance of Steam Plant	18,763,000	21,170,000	9,450,000	5,940,000	8,550,000
175	Pollution Control Projects	12,800,000	14,500,000	16,380,000	16,476,000	23,810,000
	Total Thermal Production Plant	$ 86,941,000	$ 64,235,000	$ 53,530,000	$ 39,416,000	$ 65,510,000
	HYDROELECTRIC PRODUCTION PLANT					
180	Improvements to Hydroelectric Plants	$ 2,913,000	$ 3,550,000	$ 2,750,000	$ 2,750,000	$ 2,970,000
	Total Hydroelectricic Production Plant	$ 2,913,000	$ 3,550,000	$ 2,750,000	$ 2,750,000	$ 2,970,000
	OTHER PRODUCTION PLANT					
185	Improvements to Combustion Turbines	$ 13,800,000.00	$ 14,770,000.00	$ 12,300,000.00	$ 12,684,000.00	$ 13,260,000.00
187	Improvements to Balance of Simple Cycle Gas Turbines	3,300,000	3,500,000	3,500,000	3,500,000	3,500,000
190	Improvements to Combined Cycle Steam Turbines	1,700,000	4,500,000	-	5,000,000	600,000
195	Improvements to Combined Cycle Balance of Plant	1,700,000	1,500,000	800,000	1,600,000	3,250,000
196	Improvements to Combined Cycle Gas Turbines	12,600,000	9,000,000	14,930,000	16,500,000	14,000,000
198	Improvements to Combined Cycle Heat Recovery Boilers	-	-	580,000	5,390,000	1,700,000
199	Improvements to Other Production Plant	5,060,000	2,950,000	1,860,000	28,161,000	56,710,000
	Total Other Production Plant	$ 38,160,000	$ 36,220,000	$ 33,970,000	$ 72,835,000	$ 93,020,000
	TOTAL PRODUCTION PLANT	$ 128,014,000	$ 104,005,000	$ 90,250,000	$ 115,001,000	$ 161,500,000
TRANSMISSION PLANT						
205	New 230 kV Lines	$ 11,200,000	$ 13,000,000	$ 13,000,000	$ 13,700,000	$ 15,500,000
207	New 115 kV Lines	-	-	5,500,000	10,000,000	9,000,000
210	New 38 kV Lines	1,830,000	3,070,000	8,300,000	2,140,000	2,115,000
213	115 kV Underground line	88,000	-	-	-	-
215	38 kV Underground System	12,700,000	3,000,000	3,307,000	4,750,000	6,348,000
218	Submarine Cables	1,500,000	-	-	-	4,000,000
225	230/115 kV Transmission Centers & Capacity Increase	5,000,000	1,000,000	-	-	1,000,000
230	115/38 kV Transmission Centers & Capacity Increase	38,765,000	20,450,000	24,000,000	22,000,000	13,400,000
235	New 230 kV Switchyards & Expansions	-	3,000,000	3,000,000	2,000,000	8,500,000
237	New 115 kV Switchyards & Expansions	850,000	500,000	-	-	500,000
242	New 38 kV Switchyards & Expansions	4,820,000	100,000	2,200,000	7,876,000	11,308,000
252	38 kV Air Breaks (Throwovers)	-	-	-	-	200,000
255	Energy Management System (SCADA)	2,250,000	4,150,000	3,475,000	1,700,000	1,200,000
265	230 kV Line Rehabilitation	-	-	-	-	500,000
267	115 kV Line Rehabilitation	8,000,000	6,010,000	-	2,000,000	7,700,000
275	38 kV Line Rehabilitation	21,273,000	17,577,000	14,020,000	6,549,000	13,600,000

APPENDIX X
DETAILS OF CAPITAL IMPROVEMENT PROGRAM

Budget Item Number		Estimated Expenditures by Fiscal Year 2010	2011	2012	2013	2014
TRANSMISSION PLANT (Cont'd.)						
280	Transmission Pole Replacement	$ 2,000,000	$ 2,400,000	$ 2,500,000	$ 2,500,000	$ 2,470,000
285	Breaker Uprating	800,000	800,000	800,000	800,000	800,000
288	Reconstruction of Grounding Mat	50,000	50,000	-	-	1,000,000
290	Misc. Transmission Plant Improvements—Engrg. Div.	-	800,000	500,000	-	-
292	Misc. Transmission Plant Improvements—Elec. System	5,725,000	6,250,000	4,495,000	2,500,000	5,000,000
294	Other Transmission Plant	300,000	380,000	600,000	200,000	891,000
	TOTAL TRANSMISSION PLANT	$ 117,151,000	$ 82,537,000	$ 85,697,000	$ 78,715,000	$ 105,032,000
DISTRIBUTION PLANT						
300	New Distribution Substations	$ 4,450,000	$ 6,900,000	$ 6,100,000	$ 9,000,000	$ 10,900,000
305	Increase Substation Capacity	1,500,000	-	-	-	2,800,000
310	Emergency Substations	-	-	-	700,000	700,000
315	New 13 kV Substation Feeders	5,286,000	5,050,000	6,285,000	5,869,000	5,780,000
316	4.16 kV - 8.32 kV Feeders	660,000	380,000	219,000	739,000	1,380,000
320	Distribution System Expansion	1,350,000	1,790,000	2,020,000	4,950,000	2,220,000
325	Distribution Tie Lines (4.16 to 13.2 kV)	490,000	440,000	900,000	400,000	300,000
330	Line Extension to Serve New Customers	850,000	890,000	900,000	900,000	990,000
335	Construction of Urban Underground Lines	580,000	-	-	950,000	286,000
340	Installation of New Service Drops	1,400,000	1,200,000	1,200,000	1,200,000	1,200,000
360	Substation Improvements	6,790,000	3,400,000	2,400,000	2,250,000	2,500,000
365	Distribution Pole Replacement	2,781,000	2,400,000	2,500,000	2,800,000	2,870,000
368	Replacement of Commercial Service Drops	600,000	600,000	600,000	600,000	600,000
370	Improvements to the Distribution System	5,810,000	6,101,000	8,143,000	9,216,000	6,100,000
374	Improvements to 13 kV Distribution System	3,261,000	4,216,000	3,385,000	5,977,000	5,224,000
376	Ordinary Insulation Replacement	-	360,000	-	-	-
378	Improvements to and Extensions of Underground Lines	13,004,000	12,979,000	13,427,000	16,586,000	10,422,000
379	Improvements to 4.16 - 8.32 kV Underground System	1,250,000	800,000	600,000	1,200,000	1,300,000
380	Transformer Mountings	1,200,000	1,300,000	1,300,000	1,300,000	1,300,000
382	Street Lighting	2,000,000	2,200,000	2,550,000	2,600,000	2,428,000
383	Purchase of Line Transformers	1,600,000	1,600,000	1,600,000	1,600,000	1,690,000
385	Purchase of Meters	16,800,000	16,500,000	16,500,000	16,500,000	16,641,000
390	Purchase and Install Brakers, Sectionalizers, & Reclosers	1,000,000	1,000,000	1,000,000	1,000,000	687,000
392	Purchase and Install Voltage Regulators	-	500,000	500,000	500,000	520,000
395	Purchase and Install Distribution Line Capacitors	150,000	500,000	500,000	500,000	500,000
397	Line Voltage Converter	500,000	600,000	600,000	600,000	660,000
399	Other Distribution Projects	2,010,000	2,540,000	2,290,000	2,000,000	2,000,000
	TOTAL DISTRIBUTION PLANT	$ 75,322,000	$ 74,246,000	$ 75,519,000	$ 89,937,000	$ 81,998,000

APPENDIX X
DETAILS OF CAPITAL IMPROVEMENT PROGRAM

Budget Item Number		Estimated Expenditures by Fiscal Year 2010	2011	2012	2013	2014
GENERAL PLANT						
	GENERAL LAND AND BUILDINGS					
400	Land and Rights-of-Way	$ 4,001,000	$ 5,001,000	$ 5,001,000	$ 10,001,000	$ 8,001,000
410	Construction of New Warehouses	-	-	-	4,800,000	-
430	Construction of New Technical Offices	-	-	500,000	6,400,000	3,800,000
462	Minor Improvements to Technical Offices	400,000	900,000	910,000	1,060,000	905,000
464	Improvements to Technical Offices	300,000	-	-	1,000,000	1,000,000
468	Improvements to Warehouses	405,000	160,000	160,000	205,000	660,000
470	Improvements to Workshops	300,000	500,000	600,000	600,000	650,000
472	Improvements to Other Buildings	100,000	600,000	400,000	330,000	270,000
474	Improvements to Operations Buildings & Grounds-Syst.Oper.	-	500,000	500,000	-	-
476	Improvements to Other Buildings & Grounds-Elect. System	1,000,000	50,000	2,550,000	1,000,000	1,250,000
478	Improvements to Buildings & Grounds--Admin. Serv.	520,000	570,000	600,000	600,000	625,000
480	Improvements to Buildings & Grounds--Cust. Serv. Offices	800,000	700,000	1,330,000	1,290,000	1,265,000
	TOTAL GENERAL LAND AND BUILDINGS	$ 7,826,000	$ 8,981,000	$ 12,551,000	$ 27,286,000	$ 18,426,000
	EQUIPMENT					
	OFFICE EQUIPMENT					
512	Electric System	$ -	$ 200,000	$ 200,000	$ 300,000	$ 80,000
513	Client Service	-	-	100,000	100,000	100,000
514	Transmission & Distribution	-	-	150,000	290,000	365,000
	Total Office Equipment	-	200,000	450,000	690,000	545,000
	COMPUTER EQUIPMENT					
520	Executive Offices	50,000	250,000	260,000	220,000	220,000
521	Information Systems	1,500,000	3,187,000	3,326,000	3,329,000	3,353,000
522	Legal	5,000	5,000	25,000	5,000	5,000
523	Planning & Environmental	40,000	120,000	170,000	120,000	175,000
524	Engineering	100,000	30,000	-	-	-
525	Finance	20,000	5,000	5,000	5,000	5,000
526	Administrative Services	-	100,000	50,000	190,000	600,000
527	Human Resources	20,000	80,000	120,000	80,000	80,000
528	Electric System	500,000	653,000	3,935,000	3,000,000	400,000
529	Client Service	3,050,000	6,300,000	6,400,000	6,300,000	6,300,000
530	Transmission & Distribution	100,000	450,000	571,000	673,000	678,000
	Total Computer Equipment	5,385,000	11,180,000	14,862,000	13,922,000	11,816,000
	TRANSPORTATION EQUIPMENT					
540	Air Transportation Equipment	3,550,000	2,000,000	-	-	65,000
545	Land Transportation Equipment	3,000,000	6,500,000	5,000,000	8,500,000	6,000,000
	Total Transportation Equipment	$ 6,550,000	$ 8,500,000	$ 5,000,000	$ 8,500,000	$ 6,065,000

APPENDIX X
DETAILS OF CAPITAL IMPROVEMENT PROGRAM

Budget Item Number		Estimated Expenditures by Fiscal Year 2010	2011	2012	2013	2014
	COMMUNICATIONS EQUIPMENT					
550	Communications Equipment-Electric System	$ 160,000	$ 400,000	$ 980,000	$ 1,200,000	$ 2,000,000
551	Communications Equipment-Client Services	210,000	210,000	185,000	265,000	275,000
553	Communications Equipment-T&D	100,000	100,000	100,000	100,000	100,000
555	Telephone and Data lines	500,000	1,000,000	1,000,000	1,000,000	800,000
	Total Communication Equipment	$ 970,000	$ 1,710,000	$ 2,265,000	$ 2,565,000	$ 3,175,000
	OTHER EQUIPMENT					
560	Planning and Environmental	$ 545,000	$ 490,000	$ 425,000	$ 375,000	$ 675,000
562	Engineering	-	800,000	1,200,000	775,000	750,000
564	Administrative Services	-	250,000	580,000	180,000	240,000
565	Transportation Workshop	230,000	170,000	100,000	145,000	175,000
566	Human Resources	-	-	-	-	40,000
568	Electric System	1,005,000	1,115,000	3,145,000	2,410,000	1,250,000
570	Client Services	280,000	320,000	314,000	264,000	358,000
572	Transmission and Distribution	1,047,000	1,180,000	2,000,000	2,070,000	1,750,000
576	Purchase Other Equipment - Corporate Security	400,000	300,000	1,150,000	400,000	200,000
	Total Other Equipment	$ 3,507,000	$ 4,625,000	$ 8,914,000	$ 6,619,000	$ 5,438,000
	TOTAL EQUIPMENT	$ 16,412,000	$ 26,215,000	$ 31,491,000	$ 32,296,000	$ 27,039,000
TOTAL GENERAL PLANT		$ 24,238,000	$ 35,196,000	$ 44,042,000	$ 59,582,000	$ 45,465,000
PRELIMIN. SURVEYS & INVESTIGATIONS						
600	Engineering	$ 4,175,000	$ 3,000,000	$ 4,000,000	$ 5,000,000	$ 5,000,000
605	Administrative Services	$ 250,000	$ 200,000	$ 200,000	$ 200,000	$ 250,000
610	Planning and Environmental	350,000	216,000	100,000	1,260,000	410,000
611	Renewable Energy Sources	400,000	500,000	92,000	205,000	245,000
619	Preliminary Studies--Transmission & Distribution	100,000	100,000	100,000	100,000	100,000
	TOTAL PRELIMIN. SURVEYS & INVESTIGATIONS	$ 5,275,000	$ 4,016,000	$ 4,492,000	$ 6,765,000	$ 6,005,000
NET CAPITAL IMPROVEMENT PROGRAM		$ 350,000,000	$ 300,000,000	$ 300,000,000	$ 350,000,000	$ 400,000,000