THIRTY-EIGHTH 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 2011

AMENDED

URS

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April 26, 2012

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 Amended Thirty-eighth Annual Report (for fiscal year 2011) 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.

When this report was initially published as of February 23, 2012 we noted that the Authority was updating its budgets and forecasts for fiscal year 2013 and after; the Capital Improvement Program for these years was also being reviewed. This amended report incorporates the budgets and forecasts that were subsequently developed and are consistent with those in the Official Statement prepared for the Power Revenue Bond Series 2012A and 2012B.

Very truly yours,

George W. Romano Jr.
Consulting Group Manager

GWR/gs

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EXECUTIVE SUMMARY

This report is the Amended 38th Annual Report by the Consulting Engineers in compliance with 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 fiscal year 2011, ending June 30, 2011. When this report was initially issued on February 23, 2012 the Consulting Engineers noted that the Authority was updating its budgets, forecasts and the Capital Improvement Program for fiscal years 2013 and after. This amended report incorporates the budgets and forecasts that were subsequently developed and are consistent with those in the Official Statement prepared for the Power Revenue Bond Series 2012A and 2012B.

The Authority's energy sales in fiscal year 2011 were 3.8% less than the previous year, effectively offsetting the gain seen in fiscal year 2010; energy sales had declined in both fiscal years 2009 and 2008 by more than 5% per year. Energy sales declined in all sectors during the past fiscal year. The decline in the industrial sector was its fourth consecutive year, however, and reflected the continuing impact of the recession in Puerto Rico. The Authority predicts a 3.0% reduction in total energy sales for fiscal year 2012, a decline of 1.1% in fiscal year 2013, 0.3% growth in fiscal year 2014, improving to 1.1% and 1.5% growth for fiscal years 2015 and 2016 respectively. Consistent with the interim-period forecast, the predicted slow growth of peak demand indicates the historic peak set in fiscal year 2006 will not be reached again until 2020.

During fiscal year 2011 the Authority's costs of fuel oil steadily increased, with the annual average cost per barrel being more than 25% higher than fiscal year 2010. In this same period the costs of purchased power declined by 7%. The higher cost of fuel more than offset the decline in energy sales, resulting in the Authority's electric sales revenues increasing by 6.1% over the previous year. Net Revenues, as defined by the 1974 Agreement, in fiscal year 2011 declined by 4.2% from the previous fiscal year.

As of the end of fiscal year 2011 the Authority had signed a total of 37 Agreements to Purchase energy from 982 MW of proposed renewable energy projects. The Authority has forecasted an aggressive schedule for these projects to contribute a growing portion of the System power which could reach 10% by fiscal year 2016.

In the second quarter of fiscal year 2012 the Authority updated its forecasts of energy sales and fuel costs for the projected five year outlook; these continue to be the bases for this Annual Report. In addition, the Authority cut its budgets for the balance of fiscal year 2012 and subsequent years. In line with the budget reductions, the Authority subsequently reduced its projected Capital Improvement Program (CIP) budget, focusing largely on a reduction of $55.8 million in fiscal year 2013. Later the Authority revised its budgets for fiscal years 2013 and after; these revised budgets and forecasted expenditures are the bases for the Official Statement prepared for the Series 2012A and 2012B financings and this report.

The forecasted debt service coverage ratios based on projected 1974 Agreement debt service and Net Revenues through fiscal year 2016 exceed the minimum criteria of the 1974 Agreement and are consistent with those achieved during the five years ending in fiscal year 2011. Consistent with its commitment to generate forecasted Net Revenues going forward, the Authority is working with a consultant to identify a

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range of cost reduction measures. Combining these programs with employee attrition will provide the bases for the aggressive budgets the Authority has projected.

The Authority's current initiative to expand gas firing at its generating plants will benefit the Authority by reducing air emissions, with the objective of meeting the pending EPA hazardous air pollutant criteria, and lowering the projected cost of fuel, which will benefit the economy of Puerto Rico. In the past fiscal year the Authority completed the dual fuel conversion at Costa Sur Units 5 & 6, each a 410 MW unit. These were the first steam units to be converted because they are located adjacent to EcoEléctrica's liquefied natural gas (LNG) facility. The regasification facility was being expanded by EcoEléctrica during the past fiscal year and is scheduled to begin supplying natural gas to Costa Sur in the fourth quarter of fiscal year 2012.

The CIP through fiscal year 2016 includes budgets for the fuel conversion work at eight additional steam-electric units, a three unit combustion turbine plant and a two unit combined cycle plant. The gas conversions at the two Aguirre 450 MW steam-electric units on the south coast are included in the revised CIP; at the end of the past fiscal year the Authority was evaluating a dedicated offshore LNG supply for the Aguirre plant. The total scope of gas conversions in the CIP equals 2,420 MW of the Authority's capacity, not including those already completed units at Costa Sur (820 MW) and the Aguirre Combined Cycle Units 1 & 2, each 296 MW.

During fiscal year 2011 the Authority pursued regulatory approvals for the construction of a 92 mile pipeline from the south coast to three plants sites in the north. The largest and most time consuming effort was the Environmental Assessment filed with the US Army Corps of Engineers, whose findings were still pending at the time of this report.

The Authority's System performed well during fiscal year 2011. Following the return in fiscal year 2009 of all the Palo Seco Steam Plant units from major fire damage, the Authority's production plants showed improved reliability and availability as scheduled maintenance on other steam plants was performed as planned. During the past fiscal year the Authority and vendor engineers performed detailed inspections and evaluations of major equipment at the two large steam plants still pending major overhauls to confirm the extension of the interval between major maintenance outages; based on these inspections and evaluations, the Authority plans to complete the deferred cycle of programmed outages at its largest steam plants over the next two years. During fiscal year 2011 the Authority continued to improve its operations, resulting in a better annual net heat rate than it had achieved in the previous fiscal year. The reliability of electric service to the Authority's clients in fiscal year 2011, as measured by interruptions, consistently bettered their goals of less frequent and shorter interruptions established over the past two years.

Expenditures on capital improvement program projects during fiscal year 2011 were $411.6 million, which was 37% over budget; it was also 6% more than the capital expenditures in fiscal year 2010. The Authority has developed a lean capital expenditure plan for the next five years, with plans to reduce capital expenditures to $326.5 million in fiscal years 2012, and $300.0, $392.6, $373.0, $326.8 million in fiscal years 2013 through 2016 respectively. These budgets do not include construction of the natural gas pipeline or other natural gas infrastructure discussed above; the Authority plans to establish the funding structure for this work during fiscal year 2012.

The Authority has utilized two private cogeneration facilities for fuel diversity and cost stabilization of a portion of its generation sources. The EcoEléctrica natural gas fired cogenerating plant has been in operation since 2000, followed two years later when the coal fired AES-PR cogenerator went into service. During fiscal year 2011 these two plants produced 32.8% of the system power and demonstrated reliable operation.

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The Authority's total credits and costs to the Commonwealth for Contributions in Lieu of Taxes (CILT) and Other were $197.0 million in fiscal year 2011, or 28% of the Authority's net revenues for the fiscal year, using the 1974 Agreement accounting. The Authority's fiscal year 2011 CILT credits were less than its actual obligations for that fiscal year, consequently the unpaid balance will be paid over the next three years. CILT credits during fiscal year 2011 included installment payments on unpaid CILT obligations from fiscal years 2008, 2009 and 2010. At the end of fiscal year 2011, the outstanding deferred CILT balance totaled $176.5 million. In addition to CILT, which benefits the municipalities, the Authority also incurred costs of $38.8 million for certain Commonwealth subsidies during the fiscal year and for the amortization of the outstanding line of credit used in the 2004 settlement of the lawsuit by the municipalities.

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

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

The Consulting Engineers believes the Authority will receive sufficient revenues in fiscal year 2012 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 147% in fiscal year 2011 and is forecasted to be 223% in fiscal year 2012.

The Consulting Engineers reviewed and approved the Authority's Annual Budget of Current Expenses and Capital Expenditures for fiscal year 2012, which was adopted in June 2011; this budget was revised late in calendar year 2011 as discussed above. The budget for fiscal year 2012 includes the first year of the Authority's five year Capital Improvement Program. In fiscal year 2012 the Authority is projected to contribute 40% or $131.2 million in internally generated funds to capital expenditures; the principal source will be from the bond financings Series 2012A. This high level of funding is well above the Authority's recent performance. In the ten years through fiscal year 2011 the Authority's average internal funding was approximately 11% of its total capital expenditures. The Consulting Engineers continues to recommend the Authority should pursue as aggressively as practicable the goal of achieving and maintaining annual levels of internal funding above that last met in fiscal year 2010 when it was 16%.

The Reserve Maintenance Fund was last used in fiscal year 2008 as an interim source of funds for the recovery of the Palo Seco Steam Plant. The net withdrawals during that year were $48.6 million leaving the year-end balance of $569,000. During fiscal years 2009, 2010 and 2011 the Authority contributed $5 million per year to the Reserve Maintenance Fund, resulting in a balance of $15.7 million at the end of fiscal year 2011. The Consulting Engineers recommends the Authority make no deposit to the Reserve Maintenance Fund during fiscal year 2012.

At the end of fiscal year 2011, the Self-insurance Fund's balance was $84.6 million. During fiscal year 2007 the Consulting Engineers approved the withdrawal of moneys from the Self-insurance 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 years 2009, 2010 and 2011 the Authority deposited $10 million per year. Based on the current fund levels, the Consulting Engineers recommends the Authority deposit $5 million to the Self-insurance Fund during fiscal year 2012.

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INTRODUCTION

This is the Amended Thirty-eighth Annual Report by the Puerto Rico Electric Power Authority's (Authority) Consulting Engineers, URS Corporation (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 approximately 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.

When this report was initially issued on February 23, 2012 the Consulting Engineers noted that the Authority was updating its budgets, forecasts and the Capital Improvement Program for fiscal years 2013 and after. This amended report incorporates the budgets and forecasts that were subsequently developed and are consistent with those in the Official Statement prepared for the Power Revenue Bond Series 2012A and 2012B. For the most part the revisions in this amended report are limited to the *Financial* section and the *Appendices.*

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 2011, which ended on June 30, 2011, the System served more than 1,475,000 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 numerous 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 21, 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 is located at Monacillo, 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 86% of the $11.2 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 4,878MW comprised of 2,892 MW of steam-electric capacity, 846 MW of combustion-turbine capacity, 1,032 MW of combined-cycle capacity, 100 MW of hydroelectric capacity, and 8 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 1,032 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 440 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 also has a mobile 1 MW diesel unit on Culebra; it is not connected to the System and is not listed as standby reserve capacity.

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 capacity of 220 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 Operating Agreements (PPOA's). The Authority is in the eleventh year of a 22-year PPOA for 507 MW of gas-fired capacity from EcoEléctrica, L.P. The Authority is in the eighth year of a 25-year PPOA 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 5,839 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 2011, the transmission system was comprised of 2,450 circuit miles of lines: 364 circuit miles of 230 kV lines, 710 circuit miles of 115 kV lines, and 1,375 circuit miles of 38 kV lines. Included in the transmission system totals are 30 miles of underground 115 kV cable, 60 miles of underground 38 kV cable and 55 miles of 38 kV submarine cable. The 30 transmission switchyards located at the power plants and the 45 transmission centers located throughout the System have a total transformer capacity of 18,535 MVA. The transmission system includes 66 sectionalizer facilities with automatic air-break switches to protect the transmission network.

As of June 30, 2011, the Authority's distribution system consisted of approximately 32,500 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 4,954 MVA). The distribution system has 1,842 circuit miles of underground lines. There are 806 privately owned substations (with a total installed capacity of 3,195 MVA). The distribution system also includes approximately 1,475,000 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. The control systems in the Authority's eighteen 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. The large steam electric units at Costa Sur were converted to dual fuel burning capability during fiscal year 2011. The Authority also plans dual fuel conversion at selected other steam electric units, the combined cycle units at the San Juan Station and simple cycle gas turbines at Cambalache over the next several fiscal years.

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; 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.

The Authority purchased an asset management program during fiscal year 2010 to replace and expand the existing system which was becoming outmoded. Among the expected benefits of the new program will be the improvement of the availability of critical generation and the reliability of certain transmission assets. The program will be two years undergoing development before being launched late in 2012. During fiscal year 2011 the Authority's engineers participated in factory acceptance tests (FAT) of components of an upgrade to their Energy Management System (EMS). The EMS upgrade will also go into service during 2012. These programs are more fully described in the *Technological Systems Operations* section below.

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 2011 the Jurisdictional Boiler Inspector had certified all of the Authority's boilers within the previous 18 months.

MAINTENANCE

Routine maintenance activities are performed during environmental outages and during planned major outages which have broader scopes of work. The routine maintenance activities are charged against the plant's maintenance budget. As is common in the electric utility industry, expenditures associated with significant production plant upgrades and design modifications are capitalized rather than charged as a current maintenance expense. Typically these activities are performed during scheduled major outages, although occasionally the Authority installs capitalized components during a scheduled environmental outage. During scheduled outages the Authority also 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 includes 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; 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.

All of the Authority's fourteen steam-electric generating units were in service during fiscal year 2011. Eleven of the 14 steam-electric generating units that were in service during fiscal year 2011 underwent an environmental outage during the fiscal year. The environmental outage of Costa Sur Unit 6 was completed while the unit underwent a programmed major overhaul.

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, turbine control valve inspection, generator testing and repair, the disassembling, repairing, or replacing of 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. Major overhauls frequently include rehabilitation work on the boiler and balance of plant systems

Two of the Authority's larger units, Aguirre Unit 1 and Costa Sur Unit 5, will have been in service at least nine years before beginning their next major overhaul. The Authority completed extensive NDE in evaluating the ability of the unit to remain in service for the extended period. From these examinations they identified the critical components for repair or replacement, which would provide the best assurance of continued reliable service from the unit until the start of the delayed overhaul. The prioritized work completed on these units includes the reconditioning of low pressure turbines, replacement of dissimilar metal welds in the superheat area, repair of turbine control valves, the cleaning and testing of the generator, and main steam line modifications. This work was completed during environmental outages with extended scope and duration.

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. The Authority has completed the upgrade of 14 of the combustion turbines; the completion of the upgrade on the 15th combustion turbine is scheduled for early in fiscal year 2012. The upgrades to the remaining combustion turbines are scheduled for completion in fiscal year 2012, however, due to the low demand for their capacity the completion of the upgrades to the remaining combustion turbines are likely to be delayed. Vibration analysis, lubricating oil analysis, and other preventative maintenance, 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 six 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 six 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; however because their service is intermittent and most often at partial load the years between scheduled overhauls may exceed those of the steam-turbines. See the discussion of Aguirre Combined Cycle ST-2 below.

During October 2008 the Authority's two 220 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 160 MW and a steam turbine with a capacity of 60 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 service hours, ESH, as follows:

8,000 ESH — 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 ESH — 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 ESH — Major Inspection of the Combustion Turbine is completed with inspection and replacement of blades in the compressor section and in the turbine section.

San Juan Units 5 & 6 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 ESH.

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 2011 totaled $107.7 million, which was 9% less than the average for maintenance expenditures during the five fiscal years ending in 2011. The Authority's production maintenance budgets through fiscal year 2016 are based on extending the fiscal year 2011 levels uniformly across the period.

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, 2011

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. During fiscal year 2011 the Authority's generating capacity achieved a net heat rate of 10,451 Btu/kWh. The 2011 heat rate improved on the heat rate attained in fiscal year 2010, which had been the best heat rate ever achieved by the Authority's steam electric generating capacity. These continued improvements in efficiency are the result of scheduled maintenance, equipment monitoring and upgrades, also the introduction in 2009 of more efficient generating capacity and its dispatch.

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, 2011. The equivalent availability of the Authority-owned production plant for fiscal year 2011 was 82%, a five percentage point improvement over fiscal year 2010. During fiscal year 2011 the Aguirre Steam Plant, the Costa Sur Steam Plant, and San Juan Steam Plant made significant improvements in their availability and were the principal drivers to the higher percent of equivalent availability achieved by the Authority's thermal system during fiscal year 2011.

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

AUTHORITY'S PRODUCTION PLANT SUMMARY PERFORMANCE FISCAL YEAR 2011

	CAPACITY	INITIAL OPERATION	HEAT RATE	ANNUAL EQUIVALENT AVAILABILITY
STEAM PLANTS				
Aguirre Unit 1	450	1971	10,410	87%
Aguirre Unit 2	450	1971	10,256	93%
		Aguirre Station	10,342	90%
Costa Sur Units 1 & 2 *Removed from service 4/30/08*				
Costa Sur Unit 3	85	1960	12,843	93%
Costa Sur Unit 4	85	1962	12,410	98%
Costa Sur Unit 5	410	1969	10,977	77%
Costa Sur Unit 6	410	1972	10,789	76%
		Costa Sur Station	10,975	80%
Palo Seco Unit 1	85	1959	10,911	94%
Palo Seco Unit 2	85	1959	11,221	81%
Palo Seco Unit 3	216	1967	10,328	77%
Palo Seco Unit 4	216	1968	10,409	88%
		Palo Seco Station	10,573	84%
San Juan Unit 7	100	1964	10,904	96%
San Juan Unit 8	100	1964	11,049	55%
San Juan Unit 9	100	1966	11,767	29%
San Juan Unit 10	100	1965	11,488	84%
		San Juan Station (excl 5 & 6)		66%

	CAPACITY	INITIAL OPERATION	HEAT RATE	ANNUAL EQUIVALENT AVAILABILITY
COMBINED CYCLE UNITS				
Aguirre Combined Cycle Unit 1	296	1976		89%
Combustion Turbine 1-1	50		13,083	63%
Combustion Turbine 1-2	50		13,340	98%
Combustion Turbine 1-3	50		13,160	97%
Combustion Turbine 1-4	50		13,367	99%
Steam Turbine 1	96			90%
Aguirre Combined Cycle Unit 2	296	1975		78%
Combustion Turbine 2-1	50		41,767	2%
Combustion Turbine 2-2	50		13,306	75%
Combustion Turbine 2-3	50		13,408	97%
Combustion Turbine 2-4	50		13,466	97%
Steam Turbine 2	96			99%
		Aguirre Combined Cycle Plant	10,910	84%

	CAPACITY	INITIAL OPERATION	HEAT RATE	ANNUAL EQUIVALENT AVAILABILITY
COMBINED CYCLE UNITS (continued)				
San Juan Unit 5	220	2008	8,758	63%
Combustion Turbine 5	160			77%
Steam Turbine 5	60			29%
San Juan Unit 6	220	2008	7,807	73%
Combustion Turbine 6	160			64%
Steam Turbine 6	60			98%
		San Juan Combined Cycle Units		68%
COMBUSTION TURBINES				
Cambalache CT Power Blocks				
CCTP 1	82.5	1997	13,770	80%
CCTP 2	82.5	1997	11,938	94%
CCTP 3	82.5	1998	11,241	95%
		Cambalache CTs	12,007	90%
Frame 5 GT Power Blocks				
9 Blocks of 2 GT's	378	1971-1973	15,006	85%
Mayagüez				
GT 1	55	2009	10,169	99%
GT 2	55	2009	10,407	73%
GT 3	55	2009	10,322	91%
GT 4	55	2009	10,260	99%
		Mayagüez GTs	10,270	91%

	CAPACITY	HEAT RATE	ANNUAL EQUIVALENT AVAILABILITY
THERMAL SYSTEM			
	4,770	**10,451**	82%

	CAPACITY	INITIAL OPERATION	SERVICE FACTOR	ANNUAL EQUIVALENT AVAILABILITY
HYDRO				
Total for 21 Hydro Units	100	1929-1953	19%	75%
DIESEL GENERATORS				
Total for 6 DG sets	8	1980-2006	4%	89%

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 2012 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 (nominal 450 MW) was on line, capable of full output on June 30, 2011. The unit was scheduled from service for maintenance five times; these outages kept the unit from available status for 14 days. Five forced outages occurred during the fiscal year the longest of these occurred late in the fiscal year and kept the unit from service for 25 days. In all Aguirre Unit 1 was unavailable for 30 days while unscheduled repairs were completed. There were two conditions that led to the unit's accrual of 61 equivalent outage hours during fiscal year 2011. At the end of the fiscal year this unit had generated an average of 304 MW and had a gross capacity factor of 60%. Unit 1 was in service 7,718 hours during the fiscal year.

The unit returned from service on completion of an environmental outage in April 2010. It was scheduled for the first of its five maintenance outages in late August during which the Authority repaired feed water heater 6 and repacked a flow control valve that had been leaking. Repairs took slightly more than two days. In late September the unit was scheduled out for the repair of boiler tube leaks and for additional repairs to feed water heater 6; the unit returned to service in less than three days. During November the repair of a leak in a sampling line was completed during a one day scheduled outage. The repair of a water leak in the generator cooling system and miscellaneous boiler repairs were completed in less than two days in mid January. The unit returned to service April 1 on completion of a six day maintenance outage during which the Authority repaired the servo on the main stop valve and inspected and repaired the boiler and various mechanical components.

Unit 1 experienced five forced outages during fiscal year 2011; three of the outages were for the repair of tube failures. These failures occurred in the super heater, boiler, and furnace waterwall areas. These forced outage repairs occurred over a five month period and when combined kept the unit from service for slightly more than four days. A control system fault was repaired in a matter of hours after the unit was forced from service in early May. On May 6 a failure in a longitudinal weld on a super heater header forced the unit from service; the unit returned to service 26 days later as additional repair work was performed. Concurrent with the repair of the header, weld repairs were made to a super heater support, a section of a tube in the super heater area was replaced, and boiler tubes at several elevations were repaired. The following describes some of the other work completed during this outage: windbox and air

preheater duct was repaired, a boiler circulation pump was replaced and the motors on two of the three boiler circulation pumps were replaced, a condensate pump was replaced as was the motor on an FD fan, a servomotor's valve was inspected, vibration tests were completed on both ID fans. A hanger for the main steam line was repaired. The auxiliary and main condensers were cleaned, equipment filters were cleaned, pressurized equipment was inspected for leaks and necessary repairs completed. The main transformer was inspected and oil levels adjusted, cables were inspected and repaired, and a fault in a turbine grounding system was repaired. Pneumatic valves and the main turbine valves were inspected, as was the burner management system, additional instruments were installed on super heater header which had the failed weld. Fans and the bunker C fuel heater were cleaned. Additionally Unit 1's output was limited a total of eight times; and accrued a total of 61 equivalent outage hours. The two principal causes of these limitations were the presence of silica in boiler water caused by cooling water leakage in the condenser and a turbine control valve which was not fully operable.

This unit is scheduled to begin a major overhaul at the start of October 2011 and return to service in mid January 2012. It returned from its most recent overhaul in April 2001; the start date of this overhaul has been rescheduled several times. Anticipating this rescheduling and in accordance with technical advices the Authority has replaced critical equipment during extended environmental outages and has inspected other equipment to assess their ability to provide reliable service until the start of the major overhaul. These actions have enabled this unit to go well beyond the typical seven year interval between overhauls. During the major overhaul east, west, and rear waterwall sections will be replaced as will the windbox and boiler corners. Ductwork will be repaired and a dozen expansion joints will be replaced. Approximately 445 superheater header inlet and outlet nipples will be replaced. Additional drains will be installed on the main steam line. The condenser will be cleaned and the waterboxes replaced. The HP/IP turbine rotor will be replaced and the crack in the HP casing repaired. The generator will be opened, the stator cleaned and inspected, the generator's rotor will be replaced and a new voltage regulator installed. The turbine driven boiler feed pump (BFP) will be cleaned and inspected. The motors on both start-up BFPs will be replaced. Preventative maintenance will be performed on electric motors, breakers, and transformers. Relays will be tested and recalibrated. The distributive control system (DCS) will be upgraded. Cable tray will be replaced. The Authority will complete a portion of the conversion of this unit to dual fuel capability. Following the installation of the replacement corners the Authority will install burners capable of gas firing and other burners capable of being fired by residual fuel oil. The control system to operate these burners will be installed however the external piping, manifolds and valves for the gas firing of this unit will be installed at a later date. Most of the capital projects budgeted for the past fiscal year for the Aguirre plant were focused on procurements associated with the overhaul of Unit 1 and with the requalification of the HP/IP rotor that will be removed during the overhaul. Additional fire suppression pump skids were installed during fiscal year 2011. The refurbishment of boiler steel on Units 1 & 2 will continue for the next three years. Among the Aguirre projects being managed by engineering are the construction of a new raw water storage tank and the installation of a reverse osmosis (RO), water treatment unit. During 2013 the Authority will begin receiving water from Lake Patillas, this source of raw water for the Aguirre Station will replace the ground well water presently used and will reduce the cost of water treatment. The inspection and refurbishment of residual oil storage tanks at Aguirre will continue during fiscal year 2012. Unit 1 is capable of regulating frequency between 230 and 430 MW. For fiscal year 2011 the Aguirre Steam Plant reported a slightly higher net heat rate than was achieved during fiscal year 2010; the two Aguirre steam electric units again recorded a lower rate of auxiliary energy consumption than was recorded by steam electric units at the Authority's other stations.

ASP Unit No. 2 (nominal 450 MW) was available for service, capable of full output on June 30, 2011. Late in fiscal year 2010 this unit was forced from service by the failure of its main power transformer (MPT). While the transformer was being replaced with a spare transformer the Authority performed the cleanings, inspections and replacements that constitute an environmental outage. The unit returned to service at the end of the first week of fiscal year 2011. The unit was scheduled from service seven times, these outages kept it from service for a total of approximately 18 days. Approximately ten days were lost during the fiscal year as a result of five forced outages. The unit was in service for 8,104 hours during the fiscal year. During fiscal year 2011 Unit 2 generated an average of 299 MW, achieved a capacity factor of 61%. All feed water heaters were in service and Unit 2 was capable of regulating frequency on June 30, 2011.

Unit 2 was scheduled from service twice during August, these outages accounted for approximately five of the 18 maintenance outage days. During the first the Authority cleaned an air preheater and made a number of boiler repairs. Additional boiler repairs were completed during the second of these multiple day outages. A cooling water leak in the generator stator was repaired during a five day maintenance outage in September. The repair of a leak in high pressure heater 6 was completed during a one day outage in October. Boiler tube repairs and the repair of a leak at the MPT were completed during a two day maintenance outage in March. The repair of a steam leak in the crossover line from the IP turbine was made during a three day maintenance outage in April. The last of the maintenance outages during fiscal year 2011 was a two day outage for the repair of leaks in the furnace waterwall.

Unit 2 was forced from service 11 days before the start of fiscal year 2011 by a failure of its MPT. On July 8 the installation of the spare MPT was completed and Unit 2 returned to service. During fiscal year 2011 the unit was unavailable for a total of 10 days due to forced outage events, this total includes the seven forced outage days at the start of the fiscal year. Through the end of August there were two additional forced outages. Unit 2 returned to service in less than ten hours following each of these outages. In late February a field ground tripped the unit; the Authority cleaned generator brushes and returned the unit to service in less than one day. During the last of the forced outages the unit was unavailable for approximately one day while the Authority repaired waterwall leaks.

In late January 2012, following Unit 1's return to service the Authority will bring Unit 2 out of service for a four week environmental outage during which the control system that will enable the unit to burn residual fuel oil and natural gas will be installed. This is the same control system that will be installed in Unit 1 during its overhaul. The Authority will also replace sections of cable tray. The replacement of boiler corners with corners designed for dual fuel burning systems will be done at a later date. During 2011 the manufacturer of the Aguirre boilers issued a condition assessment of Unit 2's boiler. The report prioritized a number of repairs and recommended a number of boiler sections for re-evaluation in three or fewer years. In fiscal year 2010 the Authority replaced this unit's LP turbines and cleaned and inspected the unit's servos. The Authority will replace this unit's generator rotor during its major overhaul that is scheduled during fiscal year 2013. At the end of the past year the Authority was evaluating proposals for the permanent replacement of the failed MPT; delivery is expected approximately 18 months following contract award.

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 six years ago. During fiscal year 2008 the Authority's stopped reporting on the availability of these two units and identified systems within these units that provide service to one or more of the other Costa Sur units. During fiscal year 2009 the Authority began the process developing bid packages and of obtaining the approvals needed to solicit bids for the decommissioning of these units. The Authority has budgeted more than $4 million for the demolition and disposal of Units 1 & 2 in the 2012 Capital Improvement Program (CIP).

CSSP Unit No. 3 (nominal 85 MW) was in reserve shutdown for economy; available for service and capable of generating at its rated capacity on June 30, 2011. This unit was placed in reserve shutdown for economy for approximately nine months during fiscal year 2011. It was in service the equivalent of 64 days during the fiscal year. During fiscal year 2011 Unit 3 was scheduled from service once for a programmed environmental outage and forced from service twice. In all these outages kept it from service for approximately 25 days. The unit's output was limited for the equivalent of one day. Unit 3 generated an average of 53 MW, had a gross capacity factor of 11%, and was in service 1,530 hours during fiscal year 2011.

Seventeen months following its return to service on completion of its previous environmental outage Unit 3 began a 20 day environmental outage. The outage began in mid January and the unit returned to available status in early February. The unit had been in reserve shutdown for economy (RSH), for several months prior to the start of the outage and was returned to reserve shutdown for economy on completion of the environmental outage. Unit 3 was placed in RSH five times for a total of 277 days during fiscal year 2011; the most days in that status of the Authority's 14 steam-electric units. With Unit 3 in RSH the electrical section completed maintenance on the MPT.

Unit 3 was forced from service in early November following the loss of emergency power to a circulating water pump; without which the condenser lost vac-

uum and tripped the unit. Repairs were completed over the next five days; the unit was returning to service when a valve in the circulating water system closed causing condenser vacuum to drop and shutting the unit down. The valve was adjusted and the unit returned to start up in less than two hours. The unit's output was limited nine times during the fiscal year and accrued slightly more than one equivalent outage day. The Authority turned down the unit to clean the condenser seven times and accrued most of the equivalent outage hours while doing so. The unit's output was limited twice while repairs to a BFP were completed.

The Authority returned Unit 3 to service on completion of its most recent major overhaul in January 2004. Due to the dramatic reduction in service hours over the past two fiscal years the Authority has delayed the scheduled 2012 major overhaul of this unit, however, the unit has been scheduled it for an environmental outage of several weeks duration in July 2012. There were a number of station wide capital improvement projects completed during fiscal year 2011; others are ongoing. The dredging of the bay proximate to the cooling water intake area was completed in November 2010. The installation of a deluge system at the MPT and other station transformers was completed. The rehabilitation of a residual oil storage tank foundation was completed in January 2011. The construction of an elevator for the administration building is scheduled for completion during fiscal year 2012. The sheet piling of the cooling water intake channel is scheduled for completion late in fiscal year 2012. A contract for the design and procurement phases of a project to rehabilitate and double the capacity of the station's demineralized water plant was awarded; the construction of this plant is scheduled for completion in fiscal year 2013. Work is continuing on the long term environmental project to reduce the temperature of the cooling water discharge from the station's condensers.

CSSP Unit No. 4 (nominal 85 MW) like Unit 3, this unit was in reserve shutdown for economy; it was available for service and capable of generating at its rated capacity on June 30, 2011. This unit had been in RSH continuously since March 4, 2011 and was in RSH for almost nine months during fiscal year 2011. Unit 4 returned to service on completion of an environmental outage in February 2010; its next scheduled outage in July of fiscal year 2012 will be an environmental outage of two weeks duration. During fiscal year 2011 it was scheduled from service for maintenance one time and forced from service once. These outages kept it from service a total of almost nine days. Its output was limited for less than an equivalent outage day. During the fiscal year it was in service a total of 97 days. Unit 4 generated an average of 53 MW, had a gross capacity factor of 16%, and was in service 2,323 hours during fiscal year 2011.

The Authority scheduled the unit from service for maintenance on its MPT in February. It returned to available status four days later. The unit was placed in RSH five times during the fiscal year and accrued 259 days while available but not in service.

A relay failure caused a breaker serving the emergency station service transformer (ESST) to open and forced the unit from service. The relay was replaced, miscellaneous repairs were completed and the unit returned to available five days following the start of the outage. Unit 4's capacity was limited eight times during the fiscal year; these periods were brief, totaling less than one equivalent outage day. Most of the equivalent outage hours accrued while the Authority cleaned the unit's condenser to improve vacuum and heat rate.

Unit 4 is scheduled to begin an environmental outage of three weeks duration in July 2011. In addition to the cleanings, inspections, and replacements to the boiler, associated equipment, auxiliaries, electrical equipment and control systems that comprise an environmental outage, the Authority will replace a cooling tower fan and its transmission 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, capable of generating at its rated capacity on June 30, 2011 and of regulating frequency from 300 to 350 MW. Although the dual fuel firing system was commissioned during May 2011, which enables the unit to fire both natural gas and residual oil, the unit was firing only residual oil at the end of the fiscal year. Natural gas in adequate quantity to support continuous firing is scheduled to be available during the second half of fiscal year 2012. During fiscal year 2011 the Authority scheduled this unit from service ten times. Five of these programmed outages were associated with the conversion of the unit to dual fuel firing. The conversion itself was completed in conjunction with an environmental outage and was followed by four brief planned outages during which control systems were tested and calibrated. There were five scheduled outages for maintenance; each was more than one day in duration. The unit was

placed in reserve shutdown for economy for 12 days during fiscal year 2011. There were eight forced outages during the fiscal year; seven occurred following the unit's return to service on completion of its conversion to dual fuel. The unit returned to service in a matter of hours following seven of the eight forced outages. During the fiscal year Unit 5 accrued six equivalent outage days while operating with limited capacity. Unit 5 generated an average of 264 MW, had a gross capacity factor of 48%, and was in service 6,486 hours during fiscal year 2011.

In July 2010 the Authority began construction associated with the conversion of Units 5 and 6 to dual fuel firing, natural gas and/or residual oil. The objective was to complete all phases of the conversion project that could be accomplished while the unit was in service prior to its scheduled outage in October. Civil construction for the metering station, the pressure reducing station, and piping was completed. The metering station and pressure reducing stations were installed. The installation of fuel piping from grade to burner elevations, proximate to burner corners, associated valves and instrumentation were installed prior to the unit's shutdown. The installation of electrical, instrumentation, and control systems followed the installation of mechanical equipment and piping. Work on the upgrade to the unit's fire suppression system began prior to the scheduled outage. In early October the unit began a 61 day programmed outage during which the inspections, cleanings, tests, and replacements required by the Consent Decree with the EPA were completed. Additional work included the repair of broken tubes in a high pressure feedwater heater, the overhaul of a motor driven BFP, and the replacement of the excitation system's voltage regulator. When the unit returned to available status in early December it was capable of being fired with natural gas. New boiler corners and burners were installed; the piping, valves, and manifold systems bringing natural gas to the new burners were completed. A new distributive control system (DCS) and burner management system (BMS) were installed. Additional instrumentation was installed to monitor temperature in the superheat and reheat sections. The unit returned to service in early December. In the week following its return the Authority brought the unit from service four times to make adjustments to the control systems. In February the Authority scheduled Unit 5 from service for maintenance four times; valve repairs were completed on a high pressure heater during a three day outage; a day following its return it was scheduled out for two days during which the Authority aligned the coupling.of the unit's main BFP, which is driven by the HP steam turbine The Authority plugged leaking condenser tubes during a two day maintenance outage. The unit was unavailable for five days while the shaft of the main BFP was re-aligned with its coupling and vibration reduced. The Authority scheduled the unit for maintenance in June and repaired leaks in a high pressure feedwater heater during a four day outage. The unit was placed in RSH status for approximately two days during the fiscal year.

Unit 5 was forced from service eight times during the fiscal year; four of the outages were caused by control problems in the fuel delivery system, these outages kept the unit from service for less than two days. The unit was forced from service twice by high vibration at the main BFP and lost more than four days while realignments were completed. The unit was forced out again by tube leaks in a high pressure feedwater heater and for the adjustment of fan control louvers; repairs were completed and the unit returned to service in a matter of hours. Additionally the unit's capacity was limited for the equivalent of six days during the fiscal year. The condenser was either cleaned or repaired during 19 of the periods of limited capacity. Repairs to the main BFP and to the drive on an air preheater each limited the unit three times. The unit was turned down several times while pump maintenance was performed.

Unit 5 is scheduled for a three week environmental outage in May 2012. This unit returned to service on completion of a major overhaul in July 2002; Unit 5 is presently scheduled for a major overhaul during fiscal year 2013. During the overhaul the generator's stator will be rewound, turbine sections refurbished and a Mark Vl turbine control system installed. A section of the main steam line will be replaced, new drains and supports will be installed. The condenser will be completely retubed, and the tubes in two high pressure feedwater heaters will be replaced. Deaerator regulating valves will be rebuilt. Cable tray will be replaced. Electrical equipment will be cleaned, inspected, and repaired as necessary.

CSSP Unit No. 6 (nominal 410 MW) was online capable of generating at its rated capacity on June 30, 2011 while being fired by residual fuel oil. It can regulate frequency between 270 and 350 MW. The Authority completed the dual fuel conversion of this unit in January 2011 and commissioned the unit with gas and oil firing in May 2011. An adequate supply of natural gas to support continuous firing with natural gas is scheduled to be available during the second half of fiscal year 2012. During fiscal year 2011 the

Authority scheduled Unit 6 from service eight times. There were three programmed outages. During the first of the programmed outages the Authority completed a Consent Decree mandated environmental inspection and the conversion of this unit to dual fuel burning capacity. The Authority scheduled the unit from service for maintenance five times. There were four forced outages; in all forced outages kept the unit from service for less than three days. The unit's capacity was limited for the equivalent of 25 outage days, the most of any of the Authority's steam electric units. Unit 6 was placed in reserve shutdown for economy once and returned to service five days later. Unit 6 generated an average of 264 MW, had a gross capacity factor of 53%, and was in service 7,174 hours during fiscal year 2011.

In mid-December, a week following Unit 5's return to service, Unit 6 began a 47 day programmed outage during which it underwent the Consent Decree mandated environmental cleanings, inspections, repairs, and replacements and the conversion of the unit to dual fuel burning capacity. Burner corners configured for oil and gas firing were installed as were burners, burner piping, valves, instrumentation, and control systems. The electrical section completed maintenance on Unit 6's normal station service transformer and other electrical equipment. The unit returned to service at the end of January 2011. The two other program outages were each less than four hours in duration, both followed the unit's return to service on completion of its conversion. The unit was unavailable while undergoing scheduled maintenance for 12 days during the fiscal year. Four of the five maintenance outages were of more than one day's duration. In September it was scheduled out for maintenance on its burner management system and returned to service in two days. Maintenance on both of the unit's boiler feedwater pumps accounted for the other scheduled outages. The Authority worked to correct operational issues caused by high vibration in the main turbine driven BFP during several of these outages. The unit was out of service a total of eight days while the Authority worked to re-align the BFP's shaft. The CIP allocates funds for the replacement of the internals for the turbine driven BFPs on Units 5 & 6. Delivery is scheduled in fiscal year 2012. During a two day maintenance outage in February the Authority repaired leaks in one of the unit's motor driven BFP.

The unit was forced from service twice by electrical problems and returned to service in less than half of one day each time. Condenser repairs were completed during a one day forced outage in February. Hydraulic system repairs were completed during the only other forced outage. During fiscal year 2011 Unit 6's capacity was limited 19 times; it accrued a total of 25 equivalent outage days. Twenty two of the equivalent outage days accrued during the seven times that the unit remained in service with its capacity limited while the Authority worked on the main turbine driven BFP.

The scope of the CIP for fiscal year 2011 included the conversion of Unit 6 to dual fuel firing capability and upgrades of the BMS and DCS. Unit 6 is scheduled to begin a three week environmental outage in June 2012. It returned to service on completion of its most recent major overhaul in November 2009 and is scheduled for its next major overhaul in 2015. During fiscal year 2011 this unit achieved the best heat rate of the four Costa Sur units.

Palo Seco Steam Plant

PSSP Unit No. 1 (nominal 85 MW) was on line and capable of full output. At the end of the fiscal year this unit was being dispatched in steady state at approximately 80 MW during the day and 60 MW at night following the hours of peak demand. During fiscal year 2011 this unit was scheduled from service once for a programmed outage of 21 days duration. It was forced from service twice; neither of these outages kept the unit from available status for more than a few hours. The unit's output was limited for less than two equivalent outage days. The unit was in service for a total of 7,408 hours during the fiscal year; it generated an average of 69 MW while in service and had a gross capacity factor of 68% for fiscal year 2011. Unit 1 was placed in reserve shutdown for economy for 35 days during fiscal year 2011.

In mid March, the Authority brought Unit 1 from service for a Consent Decree mandated environmental outage. The unit had been in service 16 months since completing its previous environmental outage in November 2009. In addition to the routine cleanings, inspections, resets, and recalibrations required per the Consent Decree the Authority repaired the boiler's casing to reduce air-in leakage, inspected ID fan control vanes, performed inspection and maintenance on breakers, transformers and motors. Turbine control valves were cleaned and inspected, solenoids and valves were repaired. The Authority replaced the instrument air dryers and vacuum pumps that serve this unit and Unit 2. A lube oil leak in the turning gear system was repaired and the discharge valve on a BFP was repaired. Other than the reserve shutdowns

for economy cited above this was the only scheduled outage during fiscal year 2011.

The unit accrued a total of eight forced outage hours; several while electrical repairs were made and the balance following a trip for low vacuum. In August the unit's capacity was limited twice while its condenser was cleaned. During April the unit accrued 21 equivalent outage hours (EOH), while the Authority replaced the motor on a BFP.

Unit 1 is scheduled for a two-week environmental outage in May 2012. The unit's last major overhaul was completed in April 2008. Its next overhaul is scheduled for 2014. The Authority has funded several capital projects for the Palo Seco Station. An 8" line to carry distillate fuel oil between Palo Seco and San Juan Stations is scheduled for completion early in fiscal year 2012. The award of a contract for the demolition and replacement of two residual fuel oil storage tanks has been contested; the resolution of this matter is likely to delay the works completion as much as one year. The Authority has budgeted $4.5 million for the installation of generator fire suppression systems. The installation of the suppression system is scheduled for completion in fiscal year 2013. The Authority will replace a feedwater heater during the major overhaul of this unit in fiscal year 2014.

PSSP Unit No. 2 (nominal 85 MW) was on line and capable of full output. At the end of the fiscal year this unit was being dispatched in steady state at approximately 80 MW during the day and 60 MW at night. Unit 2 was scheduled from service four times during fiscal year 2011; once for an environmental outage and three times for maintenance. These scheduled outages kept it from available status for 60 days. Also there were nine forced outages, which kept Unit 2 from service for seven days. During the fiscal year the unit was placed in reserve shutdown for economy for eight days.

The Authority took this unit from service at the start of a 59 day environmental outage with extended scope in early April. The unit returned to available status on June 5, 2011. The retubing of the units main condenser, which extended the outage, increased the condenser's vacuum by more than one inch. The retubing coupled with the replacement of the vacuum pumps produced the most significant improvement in the unit's performance. The Authority repaired high and low pressure feedwater heaters, numerous pinhole leaks, and replaced the motor on one of the unit's two BFPs. FD and ID fans were inspected and repaired. Lube oil leaks were repaired. Boiler hatchways were repaired. A broken burner tilt mechanism was repaired. The instrument air dryer was replaced. Electrical equipment including the transformers, breakers and relays were cleaned and inspected. Insulation was reinstalled. The first of the unit's maintenance outages was a one day outage during which the generator's hydrogen coolers were cleaned. Two brief maintenance outages, each of less than eight hours took place on consecutive days in January for the repair of leaks in an orifice line for a BFP.

Three of the nine forced outages kept the unit from available status for more than one day. In mid July the unit was forced from service for less than two days while boiler repairs were completed. In December the replacement of a pressure switch on the MPT and the repair of a fuel line leak were completed and the unit returned to service in less than two days. In January Unit 2 was forced from service for three days while a steam leak at the ejectors and additional boiler repairs were completed. The six other forced outages kept the unit from available status for slightly more than one day. Operator error accounted for two of the outages and turbine trips accounted for two of the remaining forced outages. These four forced outages kept Unit 2 from service for less than 24 hours. The Authority returned the unit to service in a matter of hours following the onset of the other two forced outages. The unit's output was limited eight times during fiscal year 2011. The unit's output was limited for approximately three days. The principal activities completed during the hours of limited capacity were condenser cleaning to improve vacuum and the repair of leaks on a BFP.

Unit 2 is scheduled for its next environmental outage in October 2012; it returned to service on completion of its most recent major overhaul in November 2007 and is scheduled for its next major overhaul in fiscal year 2014. During the overhaul the boiler and all turbine sections will be refurbished. The generator rotor is scheduled to be rewound in 2016.

PSSP Unit No. 3 (nominal 216 MW) was in service and being operated at reduced pressure due to boiler limitations, its output was limited to 180 MW. During fiscal year 2011 the unit was scheduled from service ten times; once early in the fiscal year for an environmental outage and nine times for maintenance. Scheduled outages accounted for 35 days during the fiscal year. The unit was forced from service 13 times; these unscheduled outages kept it from available status for a total of 34 days. The unit was in service for a total of 6,773 hours during the fiscal year; it generated an average of 162 MW and had a gross capacity

factor of 58% for fiscal year 2011. Unit 3 was not placed in reserve shutdown during fiscal year 2011.

The unit returned to available status on completion of a 23 day environmental outage in early August. During the outage Consent Decree mandated cleanings, inspections, replacements and necessary repairs were completed. Also a turbine bearing that was contributing to high turbine vibration was reworked in a mainland shop and repairs to air heater duct were completed. Several days following its return to service the unit was scheduled from service for the first of what would be three maintenance outages to rebalance the turbine and to reduce temperature and vibration at another of the turbine's bearings. The unit was unavailable for eight days while the turbine's rebalancing was completed. During October it was scheduled from service twice for the repair of boiler leaks. In late December it was scheduled from service for two days while repairs in the economizer section were completed. The repair of soot blowers on an air heater were completed during two scheduled outages, these repairs kept the unit from available status for almost three days. The unit was scheduled from service in preparation for an over speed test in February and was unavailable while repairs to a superheater spray line were completed in early May.

In early September the unit returned to service on completion of a repair on its main steam line. The repair of the crack took seven days. While the unit was out of service the Authority made a number of boiler repairs. In January the unit was forced from service for 19 days while additional weld repairs were completed on the main steam line. While the repair was in progress an incident occurred that necessitated the opening of a heavy walled boiler component. The component's repair extended the outage 14 days; the unit returned to service in mid February. The unit was forced from service three times due to operator error and returned to service each time in approximately four hours. The unit was forced out four times late in the fiscal year by fuse failures in the burner management control system. Approximately two equivalent days of service were lost while these replacements and repairs were completed. There were four other forced outages, each the result of a unique event and in each instance the Authority returned the unit to service in ten or fewer hours.

Unit 3 is scheduled to begin a four week environmental outage in July 2011. During the outage a spool piece will be installed in the main steam line. The spool piece will replace the section of the main steam line where the crack repair was made this fiscal year. A high pressure feedwater heater will also be repaired. The most recent overhaul of this unit was completed in November 2009, its next overhaul is scheduled for 2016; its scope includes boiler, turbine, and generator work.

PSSP Unit No. 4 (nominal 216 MW) was unavailable on June 30 while undergoing a scheduled environmental outage from which it is scheduled to return to available status in early July 2011. Unit 4 was scheduled from service for maintenance six times during the fiscal year. At the end of fiscal year 2011 this unit had accrued 30 days undergoing scheduled outages. There were seven events that forced the unit from service during the fiscal year; they kept the unit from service the equivalent of 11 days. The unit's output was limited three times and the unit was placed in reserve shutdown for economy twice, each time for part of a day. The unit was in service for a total of 7,762 hours during the fiscal year the most of the four Palo Seco units; it generated an average of 164 MW and had a gross capacity factor of 67% for fiscal year 2011.

On June 11, 2011 Unit 4 began an environmental outage with a scope that included the repair of an air heater, the inspection and testing of a boiler safety valve, the replacement of turbine control valve fluid, and the repair of a propane storage tank. The unit is scheduled to return to available status during the first week of July. During the second month of the fiscal year the unit was scheduled out for a three day maintenance outage during which a number of boiler repairs were completed and the condenser cleaned. The Authority repaired valves on a feedwater heater during a three day maintenance outage in October. In November the unit was inspected in preparation for the installation during fiscal year 2012 of components and control systems that would give it the capability of burning natural gas and/or residual oil. It returned to service on the third day of the scheduled outage and was next scheduled from service in December for the repair of a hydrogen leak in the generator cooling system and the inspection of the main steam intercept valve. The repair of boiler waterwall leaks was completed during a three day scheduled outage in May. In February it had been scheduled from service for a turbine control check, which was completed in less than two hours.

Of the seven forced outages Unit 4 experienced, three were of less than one day's duration and did not recur during the fiscal year. The failure of an electrical cable bringing power to the excitor tripped the unit from service. The cable was replaced and the unit returned

to service in one day. The unit was shutdown for two days due to the failure of an instrument measuring main steam flow; the instrument was replaced and the unit returned to service. The unit was forced from service by boiler waterwall tube failures on two occasions. The unit was unavailable for approximately four days while repairs were completed. The unit's capacity was limited on three occasions for a total of 37 service hours. The unit accrued approximately 21 equivalent outage hours (EOH), while the Authority replaced a motor on a BFP. The unit returned to full capacity in less than ten EOH following the start of each of the other events that caused it to be limited.

Unit 4 is scheduled to return from the most recent environmental outage in July. It is scheduled to be converted to dual fuel burning capacity during a four week outage that is scheduled to start in January 2012. The scope of work will include the replacement of boiler corners, the installation of new burners, fuel piping systems, a DCS, and a new burner management system. Unit 4 is the only steam electric unit at the Palo Seco Steam Plant that is presently scheduled for conversion to dual fuel capability. Its boiler, turbines, and generator are scheduled for a major overhaul in 2015. It returned to service on completion of its most recent overhaul in July 2009.

San Juan Steam Plant

Units 1, 2, 3, & 4 have been retired from service for more than three decades. Units 5 & 6 are discussed under the *Combined Cycle Plant* section.

SJSP Unit 7 (nominal 100 MW) was online capable of full capacity and capable of regulating frequency from 70 to 90 MW. During fiscal year 2011 this unit was scheduled from service four times for maintenance; scheduled outages kept it from service for 11 days. There were three forced outages, these outages kept the unit from service for approximately two days. The equivalent of less than three days of outage days were lost due to equipment or other failures that limited the unit's output. During the 8,339 hours that Unit 7 was in service it generated an average of 77 MW and had a gross capacity factor of 73%, which was the highest of the San Juan units.

Unit 7 returned to service on completion of an environmental outage in February 2010 and was not scheduled for an environmental outage in fiscal year 2011. During August this unit was scheduled from service for the inspection and repair of several high pressure feedwater heaters. The heaters were cleaned, tubes were plugged and the unit returned to service five days later. There were two scheduled maintenance outages in January. Unit 7 was unavailable for approximately two days, during the first of the outages the Authority cleaned the coolers in a lube oil tank and repaired a condenser valve. During the second outage in January the Authority cleaned the condenser intake filter which had become clogged with debris. The Authority experienced problems with several of the boiler's burners in March; repairs were made with the unit's capacity limited. The unit accrued 23 EOH before being taken from service at the start of what became a four day maintenance outage. During the outage the two troublesome burner registers were replaced, the condenser was cleaned and tested, and miscellaneous repairs and adjustments on other equipment were completed. Unit 7 was placed in reserve shutdown for economy twice for a total of less than five days.

During August a breaker for the emergency stop valve shorted open tripping the unit's turbine; it returned to service 13 hours later. In April there were two forced outages one was attributed to a failure in the fuel supply control and was quickly corrected and the unit returned to service in a few hours. The third and last forced outage was caused by low vacuum in the condenser. The condenser's filter was cleaned restoring adequate cooling water flow and the unit returned to service one day later. Three developments during the fiscal year accounted for almost all of the eight times that the unit's output was limited during fiscal year 2011. In December condenser maintenance limited the unit's capacity three times; with one BFP undergoing repair the unit's output was limited for part of one day's outage. In March before taking the unit out for a maintenance outage the Authority tried for five days to repair two burners. While doing this work the unit accumulated the equivalent of one day's outage.

Unit 7 is scheduled to begin a four week environmental outage in August 2011. Currently this unit is the only steam electric unit at San Juan Station scheduled for conversion to dual fuel capability. The conversion will be accomplished during a four week outage scheduled to begin in March 2012. The scope of work will include the installation of burner registers housing oil firing burners and gas firing burners, fuel piping systems, a DCS, and a new burner management system. Its next major overhaul is scheduled during 2015. It returned from its most recent major overhaul in August 2008 and is scheduled to begin its next major overhaul in 2014. Among the capital projects funded for the unit and station is the completion of the 38 kV GIS into which each of the four steam electric units will be connected. The contract for the

installation of an extensive upgrade to the station's fire suppression systems has been awarded; the installation is scheduled for completion in July 2012. Newly constructed water storage tanks will receive a protective coating as part of the CIP and an online condenser cleaning system will be installed during fiscal year 2012.

SJSP Unit 8 (nominal 100 MW) was online capable of full output. In February 2010 Unit 8 began a major overhaul from which it was scheduled to return in late July, however the outage was extended approximately 122 additional days. Six scheduled outages accounted for 162 outage days during the year; two outages were programmed and four were for maintenance.. Unit 8 was forced from service twice, these two outages combined accounted for less than one outage day. During the 4,837 hours that Unit 8 was in service it generated an average of 77 MW and had a gross capacity factor of 43%.

In February of fiscal year 2010 Unit 8 began a major overhaul from which it was scheduled to return in July. During the overhaul the generator rotor was rewound, boiler waterwall sections were replaced, and a section of the deaerator was replaced. Part of the primary and secondary superheat and reheat sections of the boiler were replaced. Cable tray sections were replaced. Inspections and maintenance activities were completed on transformers and large electrical equipment and motors. Pumps and fans were cleaned, inspected and repaired as necessary to ensure reliable operation. Switchgear was replaced, breakers were cleaned then tested, and relays were recalibrated. Turbine control and other valves were cleaned and inspected. The HP/IP and LP turbines were sent to a mainland shop for refurbishment. The reassembly of the turbines was on the critical path for the completion of the overhaul. Their return to Puerto Rico which had been scheduled for late June slipped to early August. During reassembly the seals and diaphragms were found to be the wrong size further delaying the completion of the overhaul. During the insulation of the HP turbine a crack was found in the casing near a control valve; the repair of the crack extended the outage to mid November. Several weeks following the unit's return to service it was scheduled from service for approximately five days for the removal of strainers which had been installed during the overhaul and for the completion of miscellaneous adjustments and repairs associated with the major overhaul. In January and in February the unit was scheduled from service for maintenance, combined these outages kept the unit from service for four days during which the Authority made ten waterwall tube repairs and a repair in the secondary superheater. During a seven day maintenance outage in March the Authority repaired a discharge valve on a high pressure feedwater heater, replaced a recirculation valve on a BFP and completed other maintenance activities. In June the Authority completed an inspection and cleaning of the turbine lube oil system during a six day maintenance outage.

Unit 8 returned to service in a matter of hours following its two forced outages both of which occurred in June. A sudden drop in turbine lube oil pressure forced the unit from service. The Authority returned the unit to service the same day and scheduled the maintenance outage cited above for the inspection of the turbine lube oil system. A generator output breaker opened tripping the unit from service repairs were completed; the unit returned to service in 14 hours.

Unit 8 is scheduled to begin a two week environmental outage in April 2012. It returned from its most recent major overhaul in November 2010 and is scheduled to begin its next major overhaul in 2016. The major overhaul of Unit 8 which was completed this fiscal year was included in the CIP expenditures..

SJSP Unit No. 9 (nominal 100 MW) was unavailable for service on June 30, 2011 while its generator was being repaired. During fiscal year 2011 this unit was scheduled from service twice, once for maintenance and once for an environmental outage. The unit was forced from service twice; as a result it had accumulated 235 forced outage days as of June 30, 2011 and would accrue additional outage days before its anticipated return from the second forced outage in August 2011. During September it was placed in reserve shutdown for a partial day due to a system event. During the 2,556 hours that Unit 9 was in service it generated an average of 80 MW; it recorded a gross capacity factor of 23% for fiscal year 2011.

In mid August the Authority scheduled the unit from service for maintenance. The weld repair of a steam leak at a BFP balancing drum was completed in less that two days and the unit returned to service. In mid October the unit began a 21 day environmental outage during which the Authority cleaned the condenser, repaired a turbine CV and inspected the main stop valve, in addition to the routine cleanings, inspections, calibrations and replacements called for in the Consent Decree with the EPA.

In late August the failure of a control cable forced the unit from service; the Authority repaired the cable and returned the unit to service in a matter of hours.

In early November while undergoing tests on completion of its environmental outage Unit 9's generator failed. During the event both rotor and stator were damaged; the rotor was shipped to a mainland shop to be rewound. The rewinding of the stator was completed in late March. The rotor was scheduled for return to Puerto Rico in mid May; during its rewinding, however, a crack in the rotor's core was found. Following the repair of the crack and completion of the rewinding the rotor is scheduled for delivery in Puerto Rico in mid July and the unit's return to service one month later. While the generator was being repaired the Authority replaced refractory and completed miscellaneous adjustments and repairs.

Unit 9 is scheduled for a two week environmental outage in December 2012. It returned from its most recent major overhaul in August 2003; the Authority has scheduled the next major overhaul during calendar year 2013. The Capital Improvement Program includes the turbine refurbishment through fiscal year 2014. During the overhaul the Authority will retube the unit's condenser, refurbish the turbine, and replace sections of the boiler.

SJSP Unit No. 10 (nominal 100 MW) was online capable of full output on June 30, 2011. During fiscal year 2011 it was scheduled from service six times, twice for programmed outages and three times for maintenance. The unit was unavailable for service a total of 38 days during these scheduled outages. The unit was unavailable for service an additional 16 days due to the seven forced outages it experienced during fiscal year 2011. Unit 10 was placed in reserve shutdown for economy for three days due to a System event. During the 7,272 hours that Unit 10 was in service it generated an average of 76 MW and had a gross capacity factor of 63%.

In early March Unit 10 returned to service on completion of a 19 day environmental outage during which additional work focused on improving the efficiency of the main condenser. After monitoring the unit's performance for several days the Authority scheduled it again from service for three days and completed a number of minor adjustments. The first of the three maintenance outages was a two day outage for the repair of waterwall tube leaks. The Authority scheduled the unit out for maintenance due to high temperature at a turbine bearing. Before returning the unit to service 12 days later the Authority cleaned the lube oil coolers and repaired the lube oil deflectors at the turbine bearing. The last of the maintenance outages during fiscal year 2011 was of two days duration in January for the repair of a boiler safety valve.

Two days before the start of fiscal year 2011 Unit 10 was forced from service by a leak in the attemporator's atomizing steam line. Before returning the unit to service on the fourth day of the fiscal year the Authority repaired the leak in the atomizing steam line and repaired three welds in the secondary superheater. In late July leaks in a high pressure feedwater heater forced the unit from service. Before returning the unit to service three days later the Authority found and plugged three leaking tubes in the heater and completed other maintenance activities. In early January the unit was forced from service by additional tube leaks in the same high pressure feedwater heater that had forced the unit from service in July. During the seven day forced outage the Authority plugged additional heater tubes and replaced components of a turbine control valve. Following its return from a scheduled outage in March the unit was forced from service three times due to leaking condenser tubes. The unit was unavailable for service a total of five days while leaking tubes were identified and plugged. The last of the forced outages caused a loss of one day's service; it occurred in May and was caused by a drop in vacuum attributed to condenser gate leaks. The gates were adjusted and the unit was returned to service.

Unit 10 is scheduled to begin a two week environmental outage in July 2012. It returned to service on completion of its most recent major overhaul in August 2009.

Combined-Cycle Plant

Total Generating Capacity 1,032 MW

The combined-cycle units within the Aguirre generating complex contain 592 MW and San Juan Units 5 & 6 located within the San Juan Steam Plant added 440 MW of dependable combined cycle capacity to the System. The status of these combined cycle units is discussed below.

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 2011 the Aguirre Combined Cycle plant recorded a net capacity factor of 3.9% while generating 0.9% of the System's net generation. The station's

net generation for fiscal year 2011 was approximately half of its net generation for fiscal year 2010.

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 seven of the eight CTs were available for service. The CT 1-1 that had been undergoing a major inspection at the start of fiscal year 2011 returned to service in November. In April CT 2-2 was scheduled from service for the installation of a diverter and other equipment. It is scheduled to return to available status during the first quarter of fiscal year 2012.

When the four CTs in Unit 1 are in combined service with ST -1 the steam turbine-generator is rated as having a design capacity of 96 MW. Under like dispatch ST- 2 is also rated at having 96 MW of design capacity. But a number of factors have combined to impose long term limitations on the capacity of the steam turbine-generators in both units. In fiscal year 2004 the Authority began a program to replace each CT's poorly sealing diverter. The diverters being replaced were leaking hot exhaust gases to atmosphere before the hot gases passed through the heat recovery steam generator (HRSG) and were one of the reasons the steam turbine-generators were not performing to design criteria. These hot gas losses reduced the amount of steam generated in the HRSG to below the level required for the steam turbine to generate at design conditions. Early in fiscal year 2012 the Authority will complete the diverter replacement program when the last of the eight CTs to receive a replacement diverter returns to available status.

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. Periodic cleanings and removal of scale deposits from the condenser tubes has improved condenser vacuum and each unit's heat rate. The refurbishment of vacuum pumps and other mechanical equipment to further improve performance is ongoing.

The Authority has 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 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 was 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 distributed control system (DCS) has been completed in both units. The Authority's CIP for fiscal year 2012 includes the scheduled rehabilitation of the cooling towers.

Following the decision to suspend the construction of a pipeline that would have brought natural gas to these CTs, the Authority blinded off the eight modules that gave the station dual fuel firing capability, put the nozzles in protected storage, and installed climate control air conditioners in each of the modules. The dual fuel modules have not been commissioned.

ACCP Unit No. 1 was available for service and capable of generating 260 MW. The four CTs that comprise this unit were available for service. The steam turbine-generator was limited to 60 MW, poor condenser vacuum and cooling tower limitations combined to lower the steam turbine- generator's capacity on June 30, 2011.

CT 1-1 was available for service and capable of generating 50 MW on June 30, 2011. This CT returned to available status during the second week of November 2010 on completion of a major inspection that had begun in November 2008. Early in the inspection the CT was converted to dual fuel burning capability. During the inspection the generator rotor was cleaned and inspected. The generator stator was rewedged. The buckets in the turbine's three stages were replaced and the CT's compressor rotor was sent to a mainland shop where its blades were replaced with coated blades and its bearings machined. The compressor was shipped to the mainland in March 2009 and returned to Puerto Rico 17 months later in August 2010. Pumps and other auxiliaries were inspected and needed repairs and replacements completed. Filter media in the air intake system was replaced and new air inlet ducts were installed. A new turbine exhaust system and new expansion joints were installed. Motors, breakers, relays and

switchgear were inspected and maintained by the electrical section. Following its return to service the CT was scheduled from available status twice while electrical equipment in the switchyard was cleaned. These two maintenance outages were completed in approximately ten hours. CT 1-1 is not scheduled for a combustion inspection during fiscal year 2012. During fiscal year 2011 the unit was in service 359 hours, or 6.5% of the hours that it was available for service.

CT 1-2 was available for service and capable of generating 50 MW on June 30, 2011. It underwent scheduled maintenance six times during fiscal year 2011. These outages kept it from available status a total of two days. Two maintenance outages, totaling less than one day were needed to stop a bearing lube oil leak. The realignment of the generator rotor was completed during a 16 hour maintenance outage. The electrical section cleaned switchyard equipment during two of the remaining scheduled outages. There were four forced outages; the CT returned to available status in less than fifteen hours following the onset of three of the forced outages. CT 1-2 was forced from service when a fire destroyed a cable in STAG 1. The Authority replaced the cable and returned the STAG to available status in 62 hours. The generator rotor is scheduled for replacement during a three week outage in August 2011. This CT will accrue an additional 4,000 equivalent operating hours before its next combustion inspection. During fiscal year 2010 the unit was in service 394 hours, or 4.5% of the hours that it was available for service.

CT 1-3 was available for service and capable of generating 50 MW. During fiscal year 2011 this CT was scheduled from service three times for maintenance. Two of the outages were scheduled to allow the electrical section to clean switchyard equipment. During the third maintenance outage the Authority completed preventative maintenance on the CT's turning gear. The fire that in September destroyed control cables in STAG 1 forced this CT from available status for seven days. The causes of the three forced outages that preceded the September outage were resolved in a matter of hours and the CT returned to available status. This CT is not scheduled for a combustion or hot gas path inspection during fiscal year 2012. This CT will accrue approximately 3,000 equivalent operating hours before its next scheduled combustion inspection. During fiscal year 2011 the unit was in service 600 hours, or 7% of the hours that it was available for service.

CT 1-4 was available for service and capable of generating 50 MW on June 30, 2011. This CT was in service 734 hours during fiscal year 2011, the most service hours of the eight CTs in the Aguirre Combined Cycle Plant. During the fiscal year it accrued a total of ten maintenance outage hours during the two outages that the electrical section used to clean switchyard equipment. In September this CT was forced from available status for 62 hours by a fire that destroyed control cables protecting STAG 1.That forced outage accounted for almost all of the outage hours this CT accrued during fiscal year 2011. The Authority has scheduled a three week outage in August 2011 for the replacement of the air duct on this CT. The 734 hours that CT 1-4 was in service represent 8.5% of the hours that this CT was available for service during fiscal year 2011.

ST-1 is rated at 96 MW; it was available for service and capable of generating 60 MW on June 30, 2011. The Authority scheduled ST-1 from service for three weeks in July for condenser maintenance. During the outage the Authority hydroblasted scale from the tubes and chemically cleaned the condenser. In addition the Authority repaired one of the steam turbine's two vacuum pumps and its LP heaters. It returned to available status with improved vacuum in early August. It was scheduled from service twice more. It was unavailable for nine hours while the Authority repaired a lube oil pump DC motor and briefly from late September into October while a hydrogen leak in a generator bushing was repaired. In January it was scheduled from service for a second time to repair hydrogen leaks at generator bushings. It returned to service eight days following the start of the outage. In February it was scheduled from service for one day for the repair of an air circuit breaker. There were four forced outages; the longest was 62 hours following the cable fire referenced above. Each of the other three forced outages kept the unit from available status for less than five hours. The Authority will replace a motor on one of the unit's vacuum pump during fiscal year 2012 and has scheduled two weeks for annual maintenance in August 2011 during which auxiliaries, valves, the lube oil system, and electrical equipment will be inspected. ST-1 is scheduled to begin a major inspection of 16 weeks duration in February 2012. During the outage the turbine rotors, HP & LP, diaphragms, and bearings will be inspected, repaired or replaced as necessary. The generator field and stator will be cleaned and inspected. The field will be rewound and the stator rewedged as necessary. Cooling tower fill and fill supports will be replaced. Major electrical equipment will be inspected; break-

ers cleaned and relays recalibrated. In fiscal year 2011 the unit was in service 784 hours, or 10% of its available hours.

ACCP Unit No. 2 was available for service and capable of generating 192 MW on June 30, 2011. Three of the unit's four CTs were available for service, each was capable of generating 50 MW. ST-2, the steam turbine-generator, was available but limited to 42 MW. With CT 2-2 unavailable while undergoing maintenance and with ST-2's condenser performance issues as described above ST-2's capacity was limited.

CT 2-1 was available for service and capable of generating 50 MW on June 30, 2011. This CT was in service three hours during fiscal year 2011. At the start of the year combustion problems kept it from service. During an early July start-up a stationary blade (stator) in the compressor section failed forcing the CT from service. The rotor was sent to a mainland shop for repair. Its scheduled return in early December was delayed when compressor section blades supplied by another vendor were late and certain other parts needed to complete the refurbishment were incorrect. The refurbished rotor was returned to Puerto Rico in April. In early April the Authority received the refurbished blades for the stator and completed their reinstallation by mid April. In addition to reassembly of the turbine, the Authority installed new air ducts and silencers. The CT returned to available status in late June. The July hours following the blade failure were classified as forced outage hours. In parallel to the compressor section repair the Authority performed a major inspection of this CT and classified the five months prior to February as scheduled outage hours. The hours from February 1 to CT 2-1's return on June 23, 2011 accrued as forced outage hours. Its next scheduled inspection will be a combustion inspection. In all CT 2-1 was available for service 144 hours during fiscal year 2011.

CT 2-2 was unavailable for service on June 30, 2011 while undergoing a combustion inspection. During the first quarter of fiscal year 2011 this CT was scheduled for maintenance twice, both maintenance outages were completed in less than 10 hours. In February it was scheduled from service for maintenance on electrical equipment. The longer of the two outages, 34 hours, was for the adjustment of an air circuit breaker in the switchyard. The other maintenance outage was completed in less than 6 hours. The combustion inspection began in early April, in addition to the routine scope of a combustion inspection as described in the *Maintenance* section above, the Authority will install a new diverter, replace the air intake filter house and install a new plenum section. The CT is scheduled to return to available status in late July. CT 2-2 is the last of the eight CTs to have the original diverter gate replaced. This CT accrued no forced outage hours during fiscal year 2011. During this fiscal year CT 2-2 was in service 172 hours or approximately 3% of its available hours.

CT 2-3 was available for service and capable of generating 50 MW on June 30, 2011. CT 2-3 was forced from service in August due to high lube oil temperature. The problem with the lube oil cooling system was corrected in one hour and the CT returned to available status. During the fiscal year the Authority scheduled the CT from service five times for maintenance. The longest of these outages was a four day outage in September during which maintenance was completed on the main power transformer. Maintenance on an air circuit breaker was scheduled during February and was completed in 32 hours. During April the CT's diverter gate was repaired during a 32 hour maintenance outage. The other two maintenance outages each kept CT 2-3 from available status for less than ten hours. This CT will accrue more than 1,900 equivalent operating hours before beginning its next combustion inspection. During this fiscal year CT 2-3 was in service 626 hours or approximately 7.3% of its available hours.

CT 2-4 was available for service at the end of fiscal year 2011 and capable of generating at its design capacity of 50 MW. It was scheduled from available status for maintenance six times during the fiscal year; none of these were for a combustion or a hot gas path inspection. In September the Authority completed a borescope inspection during a one day maintenance outage. Also in September the Authority performed preventative maintenance on the CT's main power transformer during a four day maintenance outage. In February the repair of a switchyard air circuit breaker was completed in 34 hours and the diverter gate was repaired during a 32 hour maintenance outage in April. The other two maintenance outages combined kept the CT from available status for less than one day. In May high bearing vibration forced CT 2-4 from available status for 27 hours; bleed valves were balanced and the fuel atomization system was adjusted. The other forced outage was from load oscillation caused by a loose control cable connection. The Authority completed a major inspection of this CT in April 2010; its next scheduled inspection will be a combustion inspection before which this CT will accrue an additional 2,000 equiv-

alent operating hours. CT 2-4 was in service for 460 hours during fiscal year 2011, these service hours were 5.4% of its available hours.

ST-2 has a design capacity of 96 MW; it was available for service, however its capacity was limited to 42 MW on June 30, 2011. It was scheduled from service three times for maintenance and forced from service twice. The only event that kept it from available status for more than one day was a 32 hour outage for the repair of a switchyard breaker during April. Electrical repairs were completed in the course of the other four outages, the longest of which kept the steam turbine from available status for eight hours. ST-2 will begin a two-week outage for annual maintenance in January 2012. During the outage the Authority will perform maintenance on auxiliaries, valves, lube oil systems, and the condenser. ST-2 is scheduled to begin a major inspection in July 2013. ST-2 was in service 578 hours during the fiscal year which was 6.6% of its available hours.

San Juan Combined Cycle

Units 1, 2, 3, & 4 have been retired from service for more than three decades. **Units 7, 8, 9 & 10** are discussed in the *Steam-Electric Production Plant* section.

SJ Unit 5 (Dependable Capacity of 220 MW) is a combined cycle unit comprised of CT 5, a combustion turbine with a capacity of 160 MW and a steam turbine, ST 5 with a capacity of 60 MW. This unit was connected to the System and accepted by the Authority in October 2008. During fiscal year 2011 this unit was available for service 9,752 hours and in service 2,098 hours. The service hours during fiscal year 2011 were slightly less than half the 4,576 service hours it accrued during fiscal year 2010. When in service its combustion turbine generated an average of 132 MW and achieved a gross capacity factor of 20%. For fiscal year 2011 the unit's steam turbine was in service 1,600 hours of the 2,533 hours that it was available for service, it generated, an average of 45 MW and recorded a gross capacity factor of 14%.

The Authority has a long term multi-year service agreement with the combustion turbine vendor to provide technical advice and 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.

SJ CT 5 was on available for service with 160 MW capacity limited to 126 MW due to a clogged compressor air inlet filter on June 30, 2011. During fiscal year 2011 this CT was unavailable for service three times while undergoing scheduled inspections and maintenance, each of these outages were of more than 24 hours duration. It was forced from service five times; repairs completed during four of these unscheduled outages kept the CT from available status for more than 24 hours. Scheduled and unscheduled outages kept the CT from available status a total of 84 days during the fiscal year. CT 5 was in service approximately 87 days and was in reserve shutdown 194 days, most of which accrued while ST 5 was unavailable while undergoing repair.

Early in fiscal year 2011 CT 5 completed 16,000 equivalent service hours (ESH), of operation at which time it was scheduled from service for a combustion inspection. During the 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 were inspected and replaced as necessary. The air inlet, compressor, turbine, and exhaust sections of the combustion turbine were inspected. Auxiliaries were inspected and needed maintenance completed. The CT returned to available status at the beginning of September. The Authority scheduled CT 5 from service for maintenance for the month of March while work continued on the repair of ST 5's turbine. In June the Authority scheduled the CT from service for one day during which the compressor section air inlet pre-filters were replaced. With ST 5 unavailable for much of fiscal year 2011 this CT was placed in reserve shutdown for economy 13 times and accrued 4,654 hours in this status during fiscal year 2011.

During September the CT was forced from service three times. The CT was forced from service by low water level in the intermediate section of the HRSG; the level was normalized and the CT returned to service in less than three days. Five days following its return to service it was forced from service when turbine lube oil pressure dropped. Following an electrical repair normal power was restored to the lube oil system and the CT returned to service less than three days from the outage's start. Several days later high conductivity in the HRSG forced CT 5 from service; the HRSG was cleaned and the CT returned to service in mid October. These three forced outages accounted for 22 of the 24 forced outage days that this CT accrued during the fiscal year. It lost a fraction of a day in April while an instrument on a sta-

tion transformer was replaced. In May a faulty check valve on the cold reheat line forced the CT from service; the valve was adjusted and CT 5 returned to available status.

CT 5 is scheduled to be removed from service in February 2012 and modified to enable it to fire natural gas or distillate. The conversion to dual fuel capability is scheduled over a four week period and is included in the 2012 CIP budget.

SJ ST 5 with a dependable capacity of 60 MW was limited to 45 MW on June 30, 2011 due to the limitation on CT 5 with which it was combined. While limited on June 30 it accrued 6 ESH. At the start of fiscal year 2011 ST 5 was unavailable; it had been forced from service in June 2010 when shroud sections in its LP turbine broke free damaging the rotor necessitating its repair in a mainland shop. During fiscal year 2011 the ST was scheduled from service once and forced from service one time in addition to the outage cited above. Scheduled and unscheduled outages kept ST 5 from available status for a total of 229 days during the fiscal year. It was placed in RSH for economy four times and spent 69 days in that status. ST 5 returned to service in April and accrued 67 service days over the remainder of fiscal year 2011.

To improve condenser vacuum the Authority scheduled the ST from service for maintenance in May. During the outage the Authority removed debris from the condenser's filters, performed maintenance inspections and returned ST 5 to available status within three days.

ST 5 was unavailable for service at the beginning of fiscal year 2011 following the June forced outage caused by the LP section shroud failures. In July CT 5 underwent a combustion inspection. The hours that accrued while the CT was unavailable for service were classified as reserve shutdown hours for ST 5. The repair of the LP turbine was performed in a mainland shop. The main steam valve's inspection was advanced and performed by the contractor under the long term service agreement (LTSA), while the rotor's refurbishment was in progress. Other valves were inspected, reassembled and stroked; the isolation buss was inspected. Routine maintenance was performed on auxiliaries. ST 5 returned to available status in mid April but was forced from service that same day by a lube oil leak at the front standard. It returned to available status the next day. During the remainder of April it was placed in RSH three times and accrued a total of ten additional equivalent days in RSH.

ST 5 will be placed in RSH when CT 5 is taken from service to be modified to make it capable of burning natural gas or distillate dual fuel.

SP Unit 6 (Dependable Capacity of 220 MW) is a combined cycle unit comprised of CT 6, a combustion turbine, with a capacity of 160 MW and a steam turbine, ST 6, with a capacity of 60 MW. The unit is a twin of Unit 5 and went into service at essentially the same time. On June 30, 2011 the unit was unavailable for service due to the failure of CT 6's generator in April 2011. When CT 6 was forced from service ST 6 was placed in reserve shutdown (RSH).When in service the combustion turbine generated an average of 140 MW. During fiscal year 2011 the combustion turbine achieved a gross capacity factor of 53%. Similar performance data was recorded for the unit's steam turbine which was in service a total of 5,091 hours during the fiscal year; it generated an average of 48 MW and had a gross capacity factor of 46 %.

SJ CT 6 At the end of fiscal year 2011 CT 6 was unavailable following a major generator failure at the start of April. It is scheduled to return to available status by the end of calendar year 2011. In August 2009 CT 6 had tripped and while shutting down the turbine lost lubrication. The repair of the turbine kept it from service for the remainder of fiscal year 2010 and into the first month of fiscal year 2011. During fiscal year 2011 CT 6 was scheduled from service three times for maintenance; these outages kept it from available status for 15 days. CT 6 was in service 222 days and in RSH for 13 days during the fiscal year. There were ten unscheduled outages that kept the CT from available status for a total of 115 days during fiscal year 2011. Nine days following the sudden failure of the CT's generator in April the Authority advanced the start of the 24,000 ESH major inspection of CT 6 originally scheduled for May 2011. CT 6 accrued 90 of its 115 forced outage days during fiscal year 2011 following the failure of its generator.

The Authority scheduled CT 6 from service twice within a three week period to rebalance the CT's turbine rotor. These outages during August and September kept the CT from available status for a total of 12 days. During a three day maintenance outage in December the Authority replaced the pre-filters on the compressor, cleaned the economizer section and completed a number of minor repairs. During the major inspection begun in April the following were replaced: fuel nozzles; combustor baskets; transition pieces; cross flame tubes; and blades in the compressor and turbine sections. Auxiliary equipment was

inspected and repaired as required. Electrical equipment was inspected; relays were recalibrated. The major inspection was completed the last day of May. Between late December and mid January this CT was shutdown and placed in reserve. Twelve of the 13 days it would accrue in RSH status were during that period.

The CT was ending a lengthy forced outage period when in returned to available status on the tenth day of the fiscal year. It would be forced from service four more times during July; the longest of these was an eight day outage when an oil leak at an instrument caused a fire in the CT's exhaust tunnel. The loss of CO2 for the fire suppression system forced the CT from service for a day in September. The CT returned to available status in less than 24 hours following the two other forced outage events in July. In September there were two forced outages, one kept the CT from service for a couple of hours and the other for four days following a trip when a breaker at the emergency station service transformer opened. A relay was recalibrated, an alarm adjusted and an electrical line repaired before the CT returned to service. There were two brief forced outages in October. On the first day of April the CT's generator shorted, there was an explosion and fire. Over the next week the generator was opened and a damage assessment was made. Before returning to service both the stator and rotor needed extensive rework. At the end of the fiscal year the stator was being rewound and rewedged and the rotor had been sent to a mainland shop for rewinding and other repairs. The generator's repair is scheduled for completion by the end of December 2011. The report identifying the cause of the generator explosion and fire will be issued during fiscal year 2012.

On the completion of the generator's repair CT 6 will be modified to enable it to fire natural gas or distillate. The conversion to dual fuel capability is scheduled over a four week period starting in January 2012, effectively moving its return to available status to February 2012.

SJ ST 6 with a dependable capacity of 60 MW was placed in reserve shutdown on June 30, 2011. It had been placed in RSH in April when CT 6 was forced from service. CT 6 is scheduled to return to service in February 2012 and ST 6 shortly thereafter. ST 6 was available for service 358 days during fiscal year 2011 and was in service 212 of those days and in RSH for 146 days. The ST was not scheduled from service during the fiscal year. It was forced from service five times; these unscheduled outages kept it from available status for seven days.

High vibration at turbine bearings forced the ST from service twice during July. The Authority adjusted a control valve and returned the steam turbine to service in less than one day. During a five day outage the Authority filled a void below the turbine's sole plate to reduce the vibration at a turbine bearing. There were three brief forced outages in October; each had a different cause and the Authority returned the ST to available status in less than ten hours after each incident. While the ST is in RSH, the Authority has inspected auxiliaries, modified heater drains, and performed preventative maintenance.

Combustion-Turbine Power

Total Generating Capacity 846 MW

Cambalache Combustion-Turbine Power Blocks

These units were designed to provide rapid response spinning reserve, 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. Prior to the return of the four Palo Seco units and the addition of new combined cycle capacity at San Juan the Authority had dispatched at least one unit daily at partial load. During the past fiscal year, however, the Cambalache units were not in daily service owing to lower demand on the System, coupled with the addition of newer more efficient capacity to the System; the high cost of distillate fuel for Cambalache also impacted the dispatch of these units. During fiscal year 2011 the station had an availability factor above 89%, however the total number of service hours of these units during fiscal year 2011 were less than one third of what they were during fiscal year 2010. To ensure their reliability the Authority rolls each unit twice weekly. The plant's air permit allows 780 unit starts per year, the equivalent of five starts per unit per week. During fiscal year 2011 there were 120 unit starts.

As part of the Via Verde Project the Authority plans to convert the Cambalache units to dual fuel firing, with the addition of natural gas. These units are located close to the gas pipeline's proposed route. The Authority has award a contract for the conversions of the three combustion turbines, which will be done sequentially starting in February 2012. Each unit will be unavailable for approximately 30 days while the conversion is completed.

In fiscal year 2011 the Authority decided not to proceed with the upgrade of the Cambalache combustion

turbines from model GT11N1 to GT11NM technology in order to focus on the fuel conversion described above. The upgrade can still be pursued in the future, resulting in a power increase from each CT of approximately 16 MW.

During fiscal year 2011 Authority personnel completed planned inspections on each of the combustion-turbines. The technical services contract with the station's original equipment supplier remains in effect through calendar year 2011. Among the several provisions of the contract is the assignment of a technical advisor, (TA). A TA has been assigned full time at Cambalache since initial operation of the combustion turbines in 1997. The Authority does not plan to extend or renew the services contract for the resident TA beyond December 2011. During May 2011 the Authority extended the contract for the supply of a TA during class C inspections and for the replacement parts needed in the hot gas path during class C inspections of the combustion turbine. These services were extended through the next eight class C inspections. The Authority's employees are responsible for the installation of the replacement parts. The service agreement also establishes the basis for the provision of additional technical assistance as required for scheduled maintenance. Refer to the *Maintenance* section for a description of the scope of a class C inspection.

During the past six years each of the CTs experienced the failure of compressor section blades. The failures were attributed in part to the corrosive effect of airborne contaminants. The Authority replaced the media in the air intake filter houses and the OEM tested a number of sacrificial anti-corrosion/erosion coatings on compressor blades to determine the most durable coating, with the goal of up to 100,000 hours of protective service for the compressor blades. Based on the OEM's analysis and recommendation, blades with the special coating were installed in the first ten rows of the compressor section of Unit 3. With the completion of a class C inspection of Unit 3 early in fiscal year 2009 the coated blades were installed in all three Cambalache units. There have been no failures since the 2009 installation of the coated blades. With the new blades the Authority no longer performs online compressor section washings. Compressor section cleanings are now done twice a year with the unit off line.

The station's air permit establishes 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. On June 30, 2011 the two CTs that were available were capable of full output, however during much of fiscal year 2011 the three units were limited to 80 MW indicating a 2.5 MW limitation. This is typical of the daytime limitation during the hotter months of the year.

The CIP for fiscal year 2011 contained budget funds for a class C inspection of Unit 1; this inspection was completed in August 2010. The 2011 and 2012 CIP included several projects related to fire suppression system upgrades and replacements. During 2011 the design and procurements associated with these systems were completed. The scope of work includes the replacement of the CO2 fire suppression system's controls, replacement of corroded piping, and the replacement of components of the foam fire suppression system. The CO2 system provides protection to the enclosed turbine areas and the foam system protects the storage tanks. Installtion of these upgrades is in the 2012 CIP; the work is scheduled to be completed concurrent with the CT's conversion to dual fuels capability in fiscal year 2012. Also during fiscal year 2012 the fuel storage tanks will undergo internal inspections.

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 (nominal 82.5 MW) was unavailable for service, undergoing scheduled maintenance on June 30, 2011. During fiscal year 2011 the unit was scheduled from service five times for a total of 73 days; the longest of which was for a 54-day Class C inspection. Three outages for maintenance accounted for another 19 outage days. There was one forced outage, which kept the unit from available status for less than one day.

This unit began a class C inspection in early July and returned to available status on August 24. In addition to the routine scope of this inspection the Authority replaced the auxiliary equipment's cooling system air fan exchangers. On inspection the blades in the compressor section were found serviceable with only normal wear. Relays were recalibrated, the unit's main power transformer (MPT) and other electrical equipment were cleaned, inspected and serviced as necessary. A section of a fuel line was replaced before the unit returned to available status. The CT was scheduled from service for one day while a BFP was

repaired. The compressor section received its semi-annual wash in November. A blow valve in the compressor section was repaired during an eight day scheduled outage in May. On June 20 the CT was scheduled from service for electrical inspection and maintenance on the NSST, it was scheduled to return to available status in early July 2011.

During October Unit 1 was forced from service by the failure of a static frequency controller's transistor. The transistor was replaced and the CT returned to available status in less than one day. There were no other forced outages during fiscal year 2011.

This CT's next inspection, a class A, will be completed during the CT's conversion to dual fuel in February 2012. For fiscal year 2011 this CT had an availability factor of 80%. Unit 1 had 38 starts, was in service 198 hours, generated an average of 76.3 MW, and had a gross capacity factor of 2%, down from 13% in fiscal year 2010.

CCTP Unit No. 2 (nominal 82.5 MW) was available for service and capable of generating 82.5 MW on June 30, 2011. During fiscal year 2011 this CT was unavailable due to scheduled outages a total of 22 days. The Authority scheduled it from service eight times during the year, three of the outages lasted less than one day. This unit was not forced from service during fiscal year 2011.

During August the Authority replaced a section of a line bringing fuel to the units. The section of pipe was replaced and the unit returned to available status after 24 hours. In October the repair of a feed water control valve was completed in one day and the CT returned to available status. In November the compressor section was washed, the Authority completed the wash in less than half of a day. A casing flange was tightened repairing a leak in less than one day during February. Three outages were scheduled for MPT maintenance. In all these outages kept the CT from available status for less than seven days between February and May. The Authority completed a class A inspection during May. The CT was unavailable for 13 days while the inspection was completed.

Unit 2 is scheduled for a class C inspection in March 2012. The scheduling of the class C inspection is premised on the unit being in service 400 hours per month. In March or April 2012 this CT will be converted to dual fuel capability. For fiscal year 2011 this CT had an availability factor of 94%; it had 43 starts, and was in service for 569 hours. It generated an average of 70 MW and had a gross capacity factor of 6% for the past fiscal year.

CCTP Unit No. 3 (nominal 82.5 MW) was available for service and capable of generating 82.5 MW on June 30, 2011. During fiscal year 2011 the unit was scheduled from service three times for a total of approximately 22 days: twice for planned outages and once time for a maintenance outage. This unit was not forced from service during fiscal year 2011.

The replacement and re-insulation of a section of fuel piping was completed during a one day maintenance outage in August. The unit returned to available status in less than one half day on completion of a scheduled compressor wash. In mid May the CT began a class B inspection that was completed 21 days later. In addition to the routine unit inspections and replacements in the CT the Authority replaced cracked tile in the combustor and performed routine maintenance on the MPT and auxiliaries. During the outage the Authority inspected generator supports and power turbine internals. The CT returned to available status on June 9, 2011.

Unit 3 is scheduled for a class C inspection in December 2012, however this schedule is based on 400 EOH per month which is a level of service not achieved during fiscal year 2011. For fiscal year 2010 this CT had an availability factor of 94%; it had 39 starts, and was in service for 403 hours. It generated an average of 72 MW. Unit 3 had a gross capacity factor of 4% for fiscal year 2011 down from 15% achieved for the prior fiscal year.

Other Combustion-Turbine Power

The Authority has nine Combustion-Turbine Power Blocks, each with two simple cycle machines. In the paragraphs that follow the terms combustion turbine and gas turbine are synonymous; these machines are 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 aero-derivative combustion turbines into service at Mayagüez. These units replaced four of the Frame 5 GTs that went into service at Mayagüez in 1972. The Mayagüez GTs provide the Authority with 220 MW of capacity at Mayagüez and a System total of 598 MW of simple cycle combustion turbine capacity. The Authority has offered the four Frame 5 GTs from Mayagüez for sale. Twenty of the GT units were in service during the fiscal year and twenty one were available for service on

June 30, 2011. For fiscal year 2011 the GTs had a combined equivalent availability of 88%.

The net generation of the GTs during fiscal year 2011 was down, being only 39% of the net generation realized in the prior fiscal year. During fiscal year 2010 the Mayagüez aero-derivative units accounted for 90% of the net generation of all GTs; in 2011 the Mayagüez units accounted for a slightly higher percentage, 92% of the net generation by all of the GTs. The Mayagüez units with newer technology were dispatched more because their net heat rate is approximately 30% lower than the other gas turbines. However due to low System-wide demand and the adequacy of capacity capable of generating at lower cost the Mayagüez units only achieved a capacity factor 5% while recording an EA of 91% for fiscal year 2011. During fiscal year 2012 the Authority has scheduled Palo Seco GTs 1-1 and 2-2 for major inspections. The major inspections will be performed sequentially and each is scheduled to be of three months duration. During routine operation engineers perform preventative maintenance tests and inspections of GTs at prescribed weekly and monthly intervals.

The GTs discussed in the following paragraphs were unavailable for service on June 30, 2011.

Jobos GT 1-1: During fiscal year 2010 the Authority completed an intermediate inspection of this GT. As part of the inspection the generator rotor was rewound in a mainland shop. While conducting pre-acceptance testing late in fiscal year 2010, excessive vibration of the generator's rotor was observed, possibly caused by crossed windings. During fiscal year 2011 the rotor was removed, inspected and balanced onsite by the contractor under warranty. At the end of fiscal year 2011 the GT was being reassembled and was scheduled for testing prior to a return to available status early in fiscal year 2012.

Daguao 1-2: This GT was in service for 15 hours and in reserve shutdown for economy 123 days during fiscal year 2011. It began a major inspection in early November during which its generator stator was rewound, the generator rotor was replaced, and a new excitation system was installed. A Mark VI control system replaced the Speedtronic system. The turbine and compressor sections were replaced as was the ratchet and torque converter. The GT was repainted and is scheduled to return to available status in July 2011.

Yabucoa 1-1: This was not in service during fiscal year 2011. In late May during a full speed no load (FSNL) test switchgear failed forcing the GT from service. The switchgear is being replaced and the GT is scheduled to return to available status in mid July 2011.

Yabucoa 1-2: While undergoing a FSNL test in mid May this GT was forced from service by a failure in the generator's stator. Stator repairs are scheduled for completion in September 2011.

Mayagüez 2A: A borescope inspection of the eight aero-derivative combustion turbines was performed in February by an OEM engineer. The inspection found that four GTs that comprise Units 1 and 2 had improper gaps between the blades in the first stage of the turbine. GT 2-A is the first of the four GTs to be repaired by the OEM under warranty. The GT removed from available status in early March and shipped to the OEM's mainland shop for repair. GT 2-A is scheduled to return to available status at the end of July. Following its return one of the other three GTs needing repair will be sent to the OEM for modification.

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 2011 the hydroelectric generating units had an aggregate equivalent availability of 75% and generated 149,794 MWh, which was 13% more than they generated during the previous fiscal year. The hydroelectric units had an annualized service factor of 19%. On June 30, 2011 the hydroelectric system was capable of generating 50 MW. Briefly, at the end of fiscal year 2011 seven units, with 37 MW of capacity, were unavailable for service. Six of the seven hydroelectric units that were unavailable on June 30, 2011 are scheduled to return to available status during the first quarter of fiscal year 2012. During June there were seven hydro units that accrued a total of 4,282 outage hours while undergoing unscheduled repairs. The Authority's largest hydroelectric unit, Yauco 1, a 25 MW unit was in service, but limited to 12 MW. Five of the 21 hydroelectric units underwent scheduled inspections and maintenance during fiscal year 2011. More than 4,555 hours were expended completing these scheduled inspections and repairs. Housekeeping at the hydroelectric stations was uniformly good, logbooks were well maintained, inspections, and operational data was well documented.

The five year CIP allocates approximately $13 million for the refurbishment of hydroelectric units through fiscal year 2016; the CIP for fiscal year 2012, however, includes only $1 million for refurbishment projects. Due to financial constraints the Authority has suspended feasibility studies related to the refurbishment of several small hydroelectric units that have not been in service for more than a dozen years. These units were located at the Carite, Isabella, and Comerio hydroelectric stations; their return to an operable condition would have required extensive replacement of components, systems and sedimentation removal.

The status of the units that were unavailable or limited at the end of fiscal year 2011 is described below.

Garzas 2-1 with a design capacity of 5 MW was in service ten hours in July 2010 before being forced from service by electrical and mechanical problems. Additional repairs to the unit's excitation system were scheduled for completion late in the fiscal year. The repair of the main control valve which was stuck in a partially open position was included in the CIP. Its repair is scheduled to enable Garzas 2-1 to return to service in July 2011. During fiscal year 2011 replacement batteries for the Garzas hydroelectric units were ordered.

Toro Negro 1-3 with a design capacity of 1.5 MW was forced from service by high vibration at generator bearing 3 in February 2011. The bearing was being repaired and the unit is scheduled to return to available status in mid July 2011.

Toro Negro 1-4 with a design capacity of 4 MW was forced from service in July 2010 by a generator failure. The unit's rotor was sent out to be rewound. The rotor's return and the generator's reassembly are scheduled t support a return to available status in late July 2011.

Dos Bocas 1-3 with a design capacity of 5 MW was unavailable for service at the start of fiscal year 2011 while its turbine thrust bearing was being refurbished. It had been damaged when a cooling line to the bearing became plugged. It returned to available status in October and was available and in service until the bearing failed again in February. The repair of the bearing and the return of this unit to available status are scheduled for July 2011.

Caonillas 1-2 with a design capacity of 9 MW was forced from service in April by water leaks in proximity to the wicket gates. To obtain access to the area of the leak the Authority will remove generator components and the turbine. It is scheduled to return to available status in late August 2011.

Caonillas 1-1 with a design capacity of 9 MW was forced from service in June 2011. Following the forced outage of Caonillas 1-2 excessive water pressure caused the Authority to limit Unit 1-1 to 6 MW. The Authority dispatched the unit in that manner until control issues forced it from service in June. It is scheduled to return to service on completion of repairs to its control system during the first quarter of fiscal year 2012.

Caonillas 2-1 with a design capacity of 3.6 MW continued 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. The Authority is evaluating proposals for the removal of sand and sedimentation from Lake Vivi and anticipates the award of a contract for this service early in fiscal year 2012.

Yauco 1 with a design capability of 25 MW is the Authority's largest hydroelectric unit. The water passing through the unit is used for irrigation and for human consumption. Damage to turbine nozzles, the turbine, and other mechanical components have limited its capacity for a number of years. In addition, obstructions in the unit's tunnel system have reduced water flow and contributed to the limitation. During fiscal year 2011 sections of the supply tunnels to Yauco 1 were inspected, trash was removed and trash rakes repaired. During this fiscal year the hot tap into the main penstock was completed and the discharge piping to complete the bypass was installed. The Authority identified a number of deficiencies with respect to the bypass system. These deficiencies were being corrected at the end of the fiscal year; after which the bypass system will be commissioned. The major overhaul of Yauco 1 will include the replacement of the turbine, nozzles and other components. The generator will be inspected and necessary repairs completed. The major overhaul of the unit is scheduled over an 18 month period.

Diesel Generators

The diesel generators installed by the Authority on the islands of Vieques and Culebra provide backup power in the event of an interruption of the power delivered by submarine cables to these islands. At the end of fiscal year 2011 the four diesel generators on Culebra had a combined capacity of 2.0 MW and were available for service. These four diesel generators were in service a total of 233 hours and generated

18 MWh. There is an additional I MW diesel generator on Culebra but it is not connected to the System.

During 2011 a contract was awarded for the rehabilitation of the emergency diesel unit station on Culebra; the contract includes the construction of diesel storage tanks. During 2012 the Authority will solicit proposals for the supply of three diesel generating units each with a 2 MW capacity, for installation on Culebra.

On Vieques the Authority's two 3 MW diesel generators were in service a total of 74 hours during the fiscal year and generated a total of 25 MWh. The Authority has awarded a contract for the replacement of the control system for the two diesel generators. The replacement system will have an open architecture for ease of troubleshooting and thereby facilitate expedited repairs

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. Following the switch to the low sulfur fuel, the two stations on the south side of the island discontinued the use of fuel additives. In fiscal year 2009 the Authority revised its distillate fuel specification and since making the revision has been burning a distillate fuel oil with a sulfur content not exceeding 0.05% sulfur in its simple and combined cycle units. This standardization has helped the Authority to realize better pricing and supply options.

The Authority continues its practice of soliciting 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.

The residual oil supply contract for the Aguirre Steam Plant was extended in March 2011 through February 2012. The Authority will request bids for the supply of residual fuel oil for Aguirre late in calendar year 2011. The Authority has three residual oil storage tanks each with a capacity of 260,000 barrels. At the end of the past fiscal year one tank was unavailable as it was being refurbished. The Aguirre units receive 70,000 barrels of residual fuel oil every three days. During fiscal year 2011 these units consumed an average of approximately 20,200 barrels per day (BPD) of residual fuel oil when both were in service.

In June 2010 the Authority awarded a contract for the supply, starting in July, of residual oil for the Costa Sur Steam Plant; during fiscal year 2011 it exercised the option for a second year's supply which runs through June 2012. Late in fiscal year 2012 the Authority plans to request bids for the supply of residual oil effective July 2012. The Authority has 800,000 barrels of residual oil storage capacity at the Costa Sur Steam Plant. The station receives 250,000 barrels of residual fuel oil every ten to fourteen days. On average these units consume approximately 20,000 BPD of residual fuel oil. During the last quarter of fiscal year 2011 Costa Sur Units 5 & 6 first fired natural gas. This was performed on a limited basis because the necessary gasification capacity expansion at the LNG facility at the nearby EcoEléctrica cogeneration plant was not completed. As discussed in the *Capacity and Energy Resource Planning* section the Authority plans to utilize gas supplied from the EcoEléctrica plant to co-fire with fuel oil at the Costa Sur Units 5 & 6 when the expansion of the cogenerator's gasification capacity becomes operational by the end of fiscal year 2012.

A contract for the supply of residual oil for the Palo Seco and San Juan Steam Plants was awarded in May 2010; however an unsuccessful bidder contested the award. The dispute over the award was resolved and the contract took effect in June 2010. The parties agreed to extend the contract through the option year that began in June 2011. The Authority plans to solicit bids for a supply contract late in fiscal year 2012. At the Palo Seco Steam Plant the Authority has the capacity to store 450,000 barrels of residual oil; at the San Juan Steam Plant there is an additional 138,000 barrels of storage capacity for residual fuel oil. These stations receive a combined total of 250,000 barrels of residual fuel oil every ten days. On average these stations consume a combined total of 25,000 BPD of residual fuel oil.

The Authority's contracts for the supply of distillate specify that the distillate not contain more than 0.05% sulfur by weight. The Authority's contract for the supply of distillate fuel for San Juan Units 5 & 6 that was awarded in February 2009 was suspended following the October 2009 devastating fire at the CAPECO facility that destroyed 32 of its 47 storage tanks. The Authority then purchased distil-

late using purchasing procedures established to cover failure to perform situations. During fiscal year 2010 the Authority purchased more than one million barrels of distillate in this manner. In July 2010 the Authority awarded a contract for the supply of distillate fuel to the Cambalache and Mayagüez gas turbines, and to the combined cycle units at Aguirre and San Juan. In July 2011 this contract was extended through its option year. The Authority plans to rebid it late in fiscal year 2012. Distillate fuels are delivered to a south coast storage facility and from there are barged to each of the four stations. During fiscal year 2011 the CAPECO facility was acquired by a new owner that has begun remediation work and restoration of fuel storage capacity; the intent is to make a portion of this capacity available to the Authority.

The Authority has not entered into a contract for the supply of distillate fuel oil for the Authority's Frame 5 21 MW combustion turbines. These combustion turbines are in service so seldom that their fuel consumption is below a level that requires more than an infrequent truck delivery of distillate fuel oil that is paid for on a price at delivery basis.

BATTERY ENERGY STORAGE SYSTEM

The 20 MW Battery Energy Storage System, BESS, at Sabana Llana was commissioned in August 2004. The plant consisted 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. Within two years of commissioning a fire in one unit forced it from service. The Authority alleges that design faults with the batteries caused the fire, consequently neither unit was returned to service. Since 2008 the parties have engaged in complex litigation with extended discovery. During 2011 the Authority continued its action against the Puerto Rican partner of the battery's manufacturer while evaluating salvage value of the more than 6,000 batteries and the future use of the building that houses them.

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 & diaphragms for Costa Sur Unit Nos. 5 & 6
- Motors for FD, ID, GRF, & air heaters for Costa Sur Units Nos. 5 & 6 and Aguirre Unit Nos.1 & 2
- Motors and pumps for condensate, boiler circulating, & boiler feed water for Costa Sur Unit Nos. 5 & 6
- NSST 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 IMPROVEMENTS

Production plant capital expenditures in millions of dollars in fiscal year 2011 amounted to $151.2. As shown in *Appendix VI, Capital Expenditures,* production plant capital expenditures in millions are forecasted to be $104.3, $121.2, $151.1, $150.7, and $116.9 in fiscal years 2012 through 2016 respectively. Details by Budget Item Number for these five fiscal years 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 applicable Federal and Commonwealth environmental laws and regulations. These responsibilities include the development of comprehensive programs to achieve the Authority's environmental performance goals. This division is charged with obtaining the permits required to increase or modify any Authority owned capacity assets prior to operating within the System.

Much of the division's efforts during fiscal year 2011 were focused on obtaining the approvals and permits to enable the construction of a 92 mile long natural gas transportation pipeline from Guayanilla in the south to San Juan in the north. The Authority plans to make a number of units on the north side of the island capable of being fired with natural gas, in addition to their present liquid fuel. The prime candidate in the metropolitan north would be the Authority's two most efficient plants, San Juan Units 5 & 6, which are combined cycle units presently burning high cost distillate fuel. Substituting to natural gas for fuel will lower their production costs, reduce emissions and reduce maintenance frequency, and therefore associated costs. While contentious debate over the gas pipeline was continuing at the end of fiscal year 2011 the Authority had obtained all but the final permit needed for the construction of the pipeline to begin. The US Army Corps of Engineers (USACE) was completing its evaluation of the Authority's routing and environmental mitigation plans for the pipeline. During the course of the evaluation the Authority responded to numerous recommendations with respect to routing, safety and environmental mitigation. Several federal agencies were preparing comments for submission to the USACE at the end of the fiscal year. Following the USACE's announcement of its intent to issue the Authority a construction permit for the project there will be a thirty day period during which comments may be submitted to the USACE. The acquisition of land along the pipeline's route was ongoing at the end of the fiscal year.

During fiscal year 2011 Costa Sur Units 5 & 6 were converted to dual fuel burning capability; in the last quarter of the year the units operated firing natural gas and residual oil for less than two weeks. Stack testing while firing natural gas confirmed significant reductions in emissions resulted from burning the clean fuel. The natural gas was supplied by EcoEléctrica LP via a pipeline from its facility adjacent to the Costa Sur Steam Plant.

The EPA's proposed finalization during fiscal year 2012 of regulations under the Clean Air Act (CAA), will establish new national emission standards for hazardous air pollutants under the mercury and air toxics standards (MATS). These regulations will be directed to coal and oil fired steam electric generating units larger than 25 MW. The pollutants subject to regulation include mercury, arsenic, chromium, nickel and other heavy metals, and acid gases such as hydrogen chloride and hydrogen fluoride, sulfur dioxide, and particulate matter. To reach the mandated emission levels of these hazardous air pollutants, the EPA will require the installation of the maximum achievable control technology (MACT). The Authority estimates that without a major conversion of its oil fired steam generating capacity to natural gas it will be required to install MACT on its oil fired steam units. The MACT for these units could consist of various retrofitted emission control systems, such as filter baghouses and flue gas desulfurization equipment and associated ancillary systems. If the EPA's proposed schedule for the implementation of MATS holds then the industry would have until January 2015 to install the MACT for the hazardous air pollutants, with a one year extension potentially available. Based on its preliminary analysis, the Authority has concluded that if it is unable to replace fuel oil with a cleaner burning fuel, natural gas, in its steam generating units that the installation of the MACT to achieve compliance with MATS would cost more than $400 million. The Authority estimates they will have a year following the implementation of these standards to develop a compliance plan.

During fiscal year 2011 the Authority performed environmental protection or environmental remediation projects at each of its major generating stations. Environmental projects performed during fiscal year 2011 were budgeted at $13.6 million. Actual 2011 expenditures totaled slightly more than $8.1 million. The Authority's five-year capital improvement program (CIP) for fiscal year 2012 through 2016 identifies environmental projects valued at $58.9 million. During fiscal year 2012 the Authority has budgeted $10.2 million to be spent among seven projects.

Approximately one quarter of the $10.2 million budgeted for environmental projects during fiscal year 2012 is dedicated to asbestos abatement projects. These projects enable the Authority to reduce exposures to asbestos containing materials through encapsulation and removal. The abatement work takes place during programmed outages such as the major overhaul of Aguirre Unit 1 scheduled during fiscal year 2012.

In fiscal year 2012 three million dollars is budgeted to fund two section 316 Clean Water Act projects; the funding is divided equally between the two projects: one project addresses cooling water intake and the other cooling water discharge at the Costa Sur Steam Plant. The section 316 (a) & (b) projects are each budgeted to cost $23 million over the five years ending in fiscal year 2016, completion of these Costa Sur projects, however, is not expected until fiscal year 2018. These are the two largest and most costly environmental projects that the Authority has currently funded. A third environmental project at the Costa Sur Steam Plant is the rehabilitation of the station's outflow channel walls; this project started several years ago and is scheduled for completion in fiscal year 2012.

The Authority has budgeted one million dollars for the refurbishment of fuel storage tanks at the Aguirre Combined Cycle Plant and in fiscal year 2012 budgeted one million dollars for the refurbishment of tanks and associated systems at the Aguirre Steam Plant. The refurbishment of the fuel storage capacity at the Aguirre Steam Plant is scheduled to continue through fiscal year 2016; at a budgeted cost of six million dollars.

Since discovery in 1997 of oil contaminated soil at the Palo Seco Steam Plant and in the area of the Palo Seco Warehouse, the Authority has taken steps to remediate contamination from oil with a low concentration of PCB that was found in monitoring wells. The Authority has removed contaminated soil and is awaiting a decision from the EPA regarding its disposal. The Authority expects a decision from the EPA regarding the disposal of this soil during fiscal year 2012. During the final phase of the remediation program the Authority will excavate a barrier trench to prevent the possible migration of a subsurface plume from reaching salt water. The barrier trench will be completed during fiscal year 2012 and has a one million dollar budget. The scope of work includes installation of additional monitoring wells.

The Authority has a program to comply with Spill Prevention Control and Countermeasures (SPCC) regulations regarding containment of potential leakage from oil containing electrical equipment in its distribution substations. During fiscal year 2011 the Authority completed the installation of signage and spill response material at all its substations. In addition it completed the construction of compliance containment at 21 of the 54 substations that need to be upgraded. The Authority has budgeted $1 million for the completion of this program.

During fiscal year 2011 the Authority removed 15 transformers from service that had a PCB concentration of between 50-499 ppm. The Authority has had a long standing program to remove transformers with oil containing PCB between 50-499 ppm and has cataloged 179 remaining transformers for removal. All of the transformers and electrical equipment with PCB concentrations greater than 499 ppm were removed from service and disposed of years ago.

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 Monacillo 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 Monacillo 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 while subsequently amended, is still in effect. 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.

During the past fiscal year 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 2011 none of the Authority's generating stations was on probation with the EPA. There were no events, leaks or spills reported during fiscal year 2011 that could lead to significant administrative action.

COGENERATORS

The Authority has entered into long-term Power Purchase Operating Agreements (PPOAs) 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 PPOAs 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 current environmental standards; both plants are highly efficient. The Authority controls the dispatch of the cogenerators' power. During fiscal year 2011 the cogenerators accounted for 32.8% of the System's net generation an increase over the 30.6% that was recorded for fiscal year 2010. (For further discussion of these power producers see the *Capacity and Energy Resource 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 2011 totaled $ 660.9 million; in fiscal year 2010 the total was $693.7 million. For fiscal years 2012 through 2016 the Authority's forecasts include the renewable energy projects discussed in the *Capacity and Energy Resource Planning* section coming on line and the costs of that power are included in forecasted total purchased power costs. The Authority, however, projects that the cogenerators will be the largest sources of purchased power through fiscal year 2016. During the five year period beginning with fiscal year 2012 the Authority forecasts the costs of cogenerator sourced purchased power in millions of dollars will be, $672.0, $802.0, $879.5, $999.9, and $1,083.9, respectively.

In the following narratives a scheduled outage will be noted regardless of duration. The sum of the forced outage hours will be noted as will the longest of the forced outage events. An unscheduled outage or limitation 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 PPOA. 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, LNG vaporizers, and associated facilities.

In accordance with the PPOA each calendar year EcoEléctrica fixes the fuel cost per million BTU for the first 76% of the station's capacity for that year. For capacity in excess of 76% the Authority has been charged based upon a spot fuel price that was set by EcoEléctrica at the time the excess capacity was dispatched. From time to time the Authority has agreed to purchase power at a capacity above the facility's nominal rating of 507 MW, however power purchases at these levels has not been formally incorporated in the PPOA.

EcoEléctrica has contracted to store and regasify LNG in sufficient quantity to supply the Authority with natural gas for the units being converted to dual fuel capability. To satisfy the Authority's need for natural gas at Costa Sur, EcoEléctrica was required to install two additional LNG regasification units. EcoEléctrica will have four regasification units when the two new units are completed. Three will be in regular service with one held in reserve. During fiscal year 2011 the permits required for their construction were obtained. The two new regasification units are scheduled for commissioning during the second half of fiscal year 2012. At that time EcoEléctrica will have enough LNG regasification capacity to maintain a continuous supply of natural gas to the nearby Costa Sur Units 5 & 6 which were converted to dual fuel firing and were commissioned to burn natural gas during fiscal year 2011.

For fiscal year 2011 EcoEléctrica achieved an equivalent availability of 93.7%, higher than the equivalent availability of 90% achieved during fiscal year 2010, and above the contractual target of 93%. By achieving the target EcoEléctrica earned the full capacity payment for fiscal year 2011. The plant had a capacity

factor of 80.7% while generating 2.2% less energy in fiscal year 2011 than in fiscal year 2010. Each of the plant's three units was in service and capable of full output on June 30, 2011.

CT 1 was unavailable for service ten days in December 2010; during an inspection cracks were found in blade roots of row two of the turbine; blades were replaced and the CT returned to service in mid-December. During the remainder of the year the unit was out of service seven times. Only one of the seven outages lasted more than one day. It was a plant wide shutdown in mid February of 27 hours duration at the request of the Authority during which a blind was installed between the CT and the steam turbine as the steam turbine was scheduled for generator repairs starting the next day. The only other outage of more than 12 hours duration was of 16 hours duration to remove the blind and to normalize the steam for the steam turbine. The sum of the outage hours for the five other outages did not equal one day of lost availability involving blinding operations and minor adjustments and repairs. The loss, however brief, of CT 1 also caused the steam turbine to be limited for a slightly longer period of time.

CT 2 was unavailable during fiscal year 2011 for the equivalent of ten days. Almost eight of these days accrued during the second and third week of December while the blades in rows 2 and 3 of the turbine were replaced. Root cracks had been found in blades in those rows of the turbine. In February CT 2 came out of service for 27 hours at the Authority's request. CT 2 came out of service in mid-March for the removal of blinds and for the conditioning of the steam generated in its HRSG for the steam turbine that was returning to service later that day. These actions kept CT 2 from service for 21 hours. There were several more instances when CT 2 was taken from service for the installation and removal of steam blinds; each time the CT returned to service in a matter of hours.

EcoEléctrica's steam turbine-generator was out of service for 39 days due to problems with generator vibration. In early February the steam turbine generator tripped due to high vibration. EcoEléctrica returned it to service in approximately six hours. Less than two weeks later it came out of service for one day at the request of the Authority; it remained out of service for 22 additional days during which EcoEléctrica replaced two of the generator's bearings. It came out of service twice more due to excessive vibration; inspections and re-alignment were completed but not before the steam turbine had accrued an additional 17 outage days. It remained in service for the remainder of the year. There was one brief, four hour long, outage during which generator brushes were replaced. The steam turbine's generation was limited for 18 days during December while first CT 1 then CT 2 was unavailable for service.

The Authority had forecast that EcoEléctrica would generate 15.8% of the System's energy during fiscal year 2011. For fiscal year 2011 EcoEléctrica provided 16.6% of the System's energy, slightly more energy than had been forecast. The Authority forecasts that EcoEléctrica, L.P. will generate 16.0% of the energy sold by the Authority during fiscal year 2012.

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 PPOA 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 2011 AES-PR accounted for 16.2% of the energy sold by the Authority, exceeding the 14.9% of the System's net generation that the Authority had forecast that AES-PR would provide. Its net generation during fiscal year 2011 was 8% more than in fiscal year 2010. For the remaining years of the PPOA's term, the plant has a target equivalent availability of 90%, a target it has achieved most years. During fiscal year 2011 AES-PR achieved an equivalent availability of 89.3%, less than 1% below the target availability and significantly above the equivalent availability of 82% recorded in fiscal year 2010 when it had a major generator failure. The plant achieved a capacity factor of 88% for all of fiscal year 2011.

Unit 1: on June 30, 2011 this 224 MW unit was online; operating with a 57 MW limitation due to an opacity control problem. Unit 1 was scheduled from service for a 24 day generator inspection in October. During the outage general maintenance was performed throughout the unit. Four conditions partially limited the unit's generation; wet fuel limited both units to approximately 109 MW for three days in July and three days in November during which Unit 1 accrued almost four of the almost five equivalent outage days that it would accrue during fiscal year 2011. Its generation was limited for a partial equivalent of a day in January for membrane repair; briefly in May by low condenser vacuum and by opacity problems as

the fiscal year ended. There were five forced outage events; three of which kept the unit from service for more than 24 hours. In November the unit was out for six days while broken boiler tubes were repaired and again for four days in June. In late May it was forced from service by water leaks. The leaks were repaired over a 13 day outage, after which the unit returned to service. The unit returned to service in less than one day following the onset of the two other forced outages.

Unit 2: was in service and capable of generating 227 MW on June 30, 2011. This unit's output was limited six times during the fiscal year and like Unit 1 accrued a total of almost five equivalent outage days. Twice the unit's generation was limited by wet fuel, once in July and again in November. During the six days that the unit was limited it accrued four equivalent outage days. The unit was limited twice during the fiscal year while membrane repairs were made. These repairs accounted for much of the other equivalent outage day the unit accrued. The other two limitations were quickly resolved; they are not described here as the unit returned to full capacity within hours. Unit 2 was forced from service three times; it was unavailable for service for 15 days as a result of these incidents. In December it was unavailable for seven days while broken tubes in the fluidized bed heat exchanger were repaired. Boiler repairs were completed during an eight day forced outage in January. The third forced outage was the result of human error following which AES-PR returned the unit to service in two hours.

The Authority forecasts that AES-PR will generate 16.2% of the energy sold by the Authority during fiscal year 2012.

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 kV and 115 kV transmission systems precedes the *Appendices.* The map shows the existing transmission system with the planned modifications to the systems through fiscal year 2016.

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 reli-

ability 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 transmission line projects and recently completed construction of a new transmission center 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. The new transmission lines will provide additional redundancy for power flow from the major production units in the south, thereby improving operational flexibility of the system and economic dispatch.

The Authority's first priority project for expansion of the 230 kV transmission lines 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 and structures to 230 kV, thereby shortening the construction schedule of the 230 kV line from the Costa Sur plant to the transmission center at Dos Bocas. Work on this section of the new transmission line is scheduled for completion in fiscal year 2012, however it will continue to operate at 115 kV until the balance of the route to Cambalache is completed. The section of the new 230 kV line between Dos Bocas and Cambalache will utilize a new right of way. The total cost of the new 230 kV line is forecasted to be $79 million. The Authority's current CIP shows spending on this project in fiscal year 2012 will total $16.4 million. Presently, the 230 kV line is scheduled for completion late in fiscal year 2013.

The second priority 230 kV transmission line project is a new line from the Aguirre generating plant to the Cayey TC, centrally located north of the generating complex. The work is scheduled to be completed in fiscal year 2016 at a cost of $44.9 million.

A third 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, however system operational constraints resulting from the prolonged outage of the Palo Seco generating plant beginning in 2006 restricted work on extensive sections that are parallel to existing 115 kV transmission lines. The estimated cost of the new line is $110 million, with completion planned for no earlier than fiscal year 2019. The CIP has $2.4 million for this project through fiscal year 2016 since most construction work will be deferred in the short-term; extensive work is scheduled to resume in fiscal year 2017.

As part of these new transmission line projects the Authority will expand the capacity of the existing 230 kV switchyards at the Costa Sur Steam Plant and the Cambalache combustion turbine station. The Costa Sur switchyard expansion was completed in fiscal year 2011 at a cost of $3 million and is scheduled to be in operation in the first quarter of fiscal year 2012. The $3 million expansion at Cambalache is scheduled for completion in fiscal year 2013.

During fiscal year 2011 the Authority completed construction of a new 230/115 kV transmission center in Ponce, at a cost of $7.7 million; it is scheduled to be operational in early fiscal year 2012. The new 450 MVA transmission center is 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.

115 kV System

The 115 kV system is comprised of 710 circuit miles of transmission lines that encircle and cross the inte-

rior 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 bulk distribution of 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 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.

The Authority plans to install a new 115 kV line that will feed the new 115/38 kV Bairoa TC, north of Caguas. Construction of the line is scheduled to start in fiscal year 2013, with completion in fiscal year 2015.

In fiscal year 2011 the Authority made substantial progress towards completion of the new 150 MVA 115/38 kV Hato Tejas transmission center located in the region of Bayamón. The project is targeted for operation in fiscal year 2012. The Authority plans to begin work on two new 150 MVA 115/38 kV transmission centers one each in fiscal years 2012 and 2013. The first transmission center project will be at Barraquintas located between existing transmission centers in Aguas Buenas and Juana Díaz; the second will be at Bairoa, part of Caguas. The first project is scheduled to be completed in fiscal year 2014; the second will follow by a year. The transmission centers are 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.

The Authority continued work on the 115/38 kV switchyard utilizing gas insulated switchgear (GIS) at the San Juan plant during the past fiscal year. The new GIS will provide interconnection with the 38 kV system; interconnection to the 115 kV system will be via the existing aerial lines. The Authority plans a second phase of the GIS project to provide a permanent interconnect with the underground 115 kV system, meanwhile that connection can be accomplished on an interim basis if required. The final phase of the GIS project is scheduled for completion in fiscal year 2015.

The Authority presently has two near-term projects increasing the capacity of an existing 115/38 kV transmission center by extending the switchyard and increasing the transformer capacity by 150 MVA. A second transformer has been installed at the Canovanas TC, in the Carolina region, with the work effectively complete in fiscal year 2011; it is scheduled for operation in fiscal year 2012. The Authority plans to install a new higher capacity transformer at the Bayamón TC at a cost of $4.7 million, with completion scheduled for fiscal year 2013. The expansion of the 115/38 kV Victoria TC, in Aguadilla, was placed in service in the past fiscal year. Concurrent with the new 450 MVA 230/115 kV Ponce TC project discussed above, in fiscal year 2011 the Authority completed construction of the 150 MVA capacity expansion of the existing 115/38 kV Ponce TC.

The Authority plans to install an additional 115/38 kV transmission center in Venezuela, near Rio Piedras in the San Juan area. The project is scheduled to begin in fiscal year 2013 with completion targeted for fiscal year 2016.

In fiscal year 2014 the Authority plans to extend the switchyard of the existing Maunabo TC and increase its capacity with the installation of a second transformer.

During fiscal years 2012 and 2013 the Authority also plans to install 115 kV section-

alizers at five 115/38 kV TC; these provide switchable isolation of portions of the 115 kV system thereby improving operational flexibility to minimize the impact of a local problem.

To protect the integrity of the transmission system in the San Juan urban area during and following extreme weather events, the Authority installed a 30-mile underground loop of 115 kV transmission cables that link the major components of its System in the metropolitan area; the scope included four new 115/38 kV GIS substations, three of which are in operation. The general configuration of the loop is shown on the 115 kV underground system map, which is color coded to demarcate the construction phases. The system can be fed through existing transmission centers in the loop and by the Palo Seco units which are interconnected with the new transmission loop. The permanent interconnection of the San Juan units is planned for fiscal year 2015.

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, 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 Palo Seco and San Juan Steam Plants. The Palo Seco GIS has been in operation since fiscal year 2009.

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. At the end of fiscal year 2011 there were 1,375 circuit miles operating at 38 kV, including 60 miles of underground line and 55 miles of submarine service to the islands of Vieques and Culebra.

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. Both rehabilitation and new work are included in the Authority's CIP.

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 its installation as well as future maintenance.

In fiscal year 2011 the Authority expended $17.7 million on 28 projects of 38 kV line rehabilitation work; the largest project involved a line in the island's interior near Ponce and constituted approximately 55% of the total expenditures. Typically 38 kV line rehabilitation projects are located throughout the island and reflect the extent and age of the 38 kV system. The Authority has budgeted $15.4 million and plans to work on 31 line rehabilitation projects in the 38 kV

system during fiscal year 2012. The two largest projects in 2012, however, dominate the fiscal year's 38 kV rehabilitation budget. The first project involves upgrading the capacity of a 38 kV line in the island's west in the area of Aguada. The second project is in the island's interior, between Comerío and Naranjito.

The Authority expended $2.8 million during fiscal year 2011 on new aerial 38 kV lines; the budget for fiscal year 2012 for these expansions is $1.0 million, with funding for four projects.

The 38 kV system also includes more than 60 miles of underground cable in mostly urban areas. In response to civic and business leader requests, the Authority is expanding the scope of the underground cable in urban and industrial areas. During fiscal year 2011 the Authority expended $1.0 million on three new and expansion underground 38 kV projects. The largest 38 kV underground project in fiscal year 2011 was the underground work at the Parque Tecnológico Las Américas (Technology Park of America) in Mora. Approximately one half of the cost of the 38 kV underground feeders in the new Parque Tecnológico Las Américas, southwest of Arecibo; was slated to be underwritten by the public and private project developers. The Technology Park has had difficulty attracting tenants, consequently additional underground work will be deferred until development activity improves.

The Authority has budgeted $6.6 million for new 38 kV underground lines in fiscal year 2012. The largest of these projects is an underground feed from the Martin Peña 38 kV GIS to a sectionalizer in the Villamar substation in Carolina. The new feeder will reinforce supply to an area with many hotels, businesses and a high density population. The project is scheduled to be complete in fiscal year 2015 at a total cost of $10.3 million.

During fiscal year 2011 the Authority expended $4.4 million to effectively complete 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.

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 2011 amounted to $77.7 million. The Authority is planning to spend $76.1 million on capital improvements to its transmission system in fiscal year 2012: $52.6 million for expansion projects and $23.5 million for rehabilitation projects. The Authority plans to spend $381.6 million on its transmission system over the next five fiscal years. 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 three voltage levels serving most clients are 4.16 kV, 8.32 kV and 13.2 kV, with a small portion distributed at 7.2 kV. At the end of fiscal year 2011 there were approximately 32,550 circuit miles in the distribution system. Approximately 25% of the distribution circuit miles are at 13.2 kV, slightly less operate at 8.32 kV and most of the balance of circuit miles are 4.16 kV lines.

While most of the Authority's primary distribution systems are overhead, almost 6% of the Authority's distribution circuit miles are underground. The Authority's distribution overhead systems are conventionally located along road rights of way, although some are located along rear lot lines or installed along the Authority's rights of way. To improve operational reliability the Authority has a program to relocate high value lines from rear lot lines. Service ties 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. During fiscal year 2011 the Authority expended $9.4 million on the construction and extension of new overhead 13.2 kV lines. Including the special project in Ponce discussed below, expenditures for under-

ground 13.2 kV lines during fiscal year 2011 were $10.4 million. The Authority also expended $2.4 million in the past year on improvements to the 13.2 kV aerial distribution system.

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.

In fiscal year 2011 the Authority completed the restoration to service of the Río Bayamón I substation, a 13.2 kV substation that had previously been damaged by fire.

The Authority plans to complete and place into service five new 13.2 kV substations under construction and increase the capacity of an existing substation. The new substations are at Río Bayamón II and Hato Tejas both in the Bayamón region, Santa Isabel in the Ponce region, Cayey in Caguas, and Yabucoa in the island's southeast. An additional transformer is being installed at the Grana substation in San Juan and is scheduled for completion during fiscal year 2012. Beginning in fiscal year 2012 the Authority intends to work on four new 13.2 kV substations that are scheduled to enter service by fiscal year 2014. Three of these substations will be installed in the San Juan area: the Palmer TC in San Juan; Martin Peña II in Río Piedras; and Caparra in Guaynabo. The fourth substation will be in Añasco in the west coastal area of the island. The Authority also plans to begin work on five new 13.2 kV substations and the conversion of two existing substations to 13.2 kV during the fiscal years 2013 to 2016. The total amounts budgeted for these substation projects during the five years through fiscal year 2016 are $23.5 million for new substations and $6.2 million for increased capacity and voltage conversion of existing substations.

In compliance with a settlement with the municipality of Ponce, the Authority agreed to improve the electric 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 Authority has taken the lead in the underground work in the historic district which requires coordination 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 is being executed in four sequential phases to minimize disruptions to the neighborhoods and local traffic. The first two phases of the work have been completed and placed in service. In fiscal year 2011 the Authority began construction of the third phase, with expenditures during the past fiscal year of $4.8 million. In response to requests from Ponce to reduce the construction duration, the Authority is evaluating executing the final phase of this project similar to a design build contract with control and oversight by the Authority. Work on the fourth phase is targeted to begin following completion of the third, unless an alternative contracting approach is taken. The final phase is targeted for completion in fiscal year 2014. The total cost for all the work is estimated to be $56 million, with the Authority's portion costing approximately $34.4 million.

Other Distribution Work

Consistent with the wide use of lower voltage distribution lines and equipment, during fiscal year 2011 the Authority expended $32.0 million on improvements to overhead distribution lines at 4.16 kV – 8.32 kV. Expenditures on improvements to underground distribution lines operating at 4.16 kV – 8.32 kV totaled $6.2 million in fiscal year 2011; these improvements typically are in urban areas. One of the Authority's improvement programs begun in the past year is installation of proprietary automatic reclosers on priority distribution feeders; the reclosers use a low power pulse signal to status the line before reclosing, thereby protecting equipment if the fault has not cleared. While initial experience has been favorable, the Authority is taking measured steps in introducing this technology to its distribution system. The current plan is to install these automatic reclosers in limited areas, basically San Juan and Caguas, to verify longer term operation.

The Authority has established a program to comply with recent EPA's requirements on Spill Prevention Control and Countermeasures (SPCC) Plans pertaining to their electrical distribution system equipment containing oil. The Authority's SPCC Plan includes spill response material and notification signage at all substations. This scope of the plan was fully imple-

mented during the past fiscal year. In addition, the SPCC Plan has identified 54 substations in which spill containment dikes will be installed. During fiscal year 2011 the Authority performed the required civil work at 21 substations; 20 more are scheduled for fiscal year 2012 and the balance will be completed in the following year.

The Authority owns 20 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 10 MVA to 44 MVA at 38 kV and 115 kV, and includes two capacitor banks at 38 kV 18 MVAR.

Distribution Plant Capital Improvements

The Authority's capital expenditures on the distribution system were $142.9 million in fiscal year 2011. The scope of these expenditures included $43.4 million in the past year for the remote read meters discussed below. The Authority is planning to spend $87.2 million on capital improvements for its distribution system in fiscal year 2012: $18.6 million for expansion projects and $68.6 million for rehabilitation projects and other distribution expenses, such as remote read meters, line transformers, breakers, sectionalizers, and reclosers. The remote read client meters discussed below have been a long term capital commitment by the Authority and they account for 22% of the Distribution CIP budget for fiscal year 2012. The Authority plans to spend $453.3 million on its distribution system capital improvements over the next five fiscal years.

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, transmission, and substation transformers are inspected on a four year cycle. 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. Relays protecting major equipment, such as transmission transformers, are tested more frequently based on when the equipment is out of service.

In response to sporadic theft of aluminum structural bracing members for their scrap metal value from transmission towers in past years, the Authority has increased inspections of transmission towers using both the helicopter patrols and inspections from the ground. Any deficiencies identified in these inspections are repaired on a priority basis.

In fiscal year 2011 the total operation and maintenance expenses for the Transmission and Distribution systems was $282.1 million, of which $176.4 million was for operations. The Authority's total Transmission and Distribution operation and maintenance budgets for the five fiscal years 2012 through 2016 are forecasted to decline 3% annually in fiscal year 2012 and 2013, with reductions of 2%, 1% and 1% in the following years, respectively; the reductions are taken from the operations budgets.

Transmission system maintenance expenses, shown in *Appendix III, Detail of Operating and Maintenance Expenses,* totaled $31.0 million in fiscal year 2011. For fiscal years 2012 through 2016 the Authority has forecasted uniform annual transmission maintenance budgets at the same level as fiscal year 2011 expenditures. 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 Maintenance Expenses,* totaled $74.8 million in fiscal year 2011. The annual budgets for fiscal years 2012 through 2016 include $74.8 million each year for distribution system maintenance expenses, based on continuing at the level of fiscal year 2011 expenditures. These expenditures include distribution system related expenditures similar to those described under transmission system maintenance expenses.

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 major production plants.

Reliability Indices

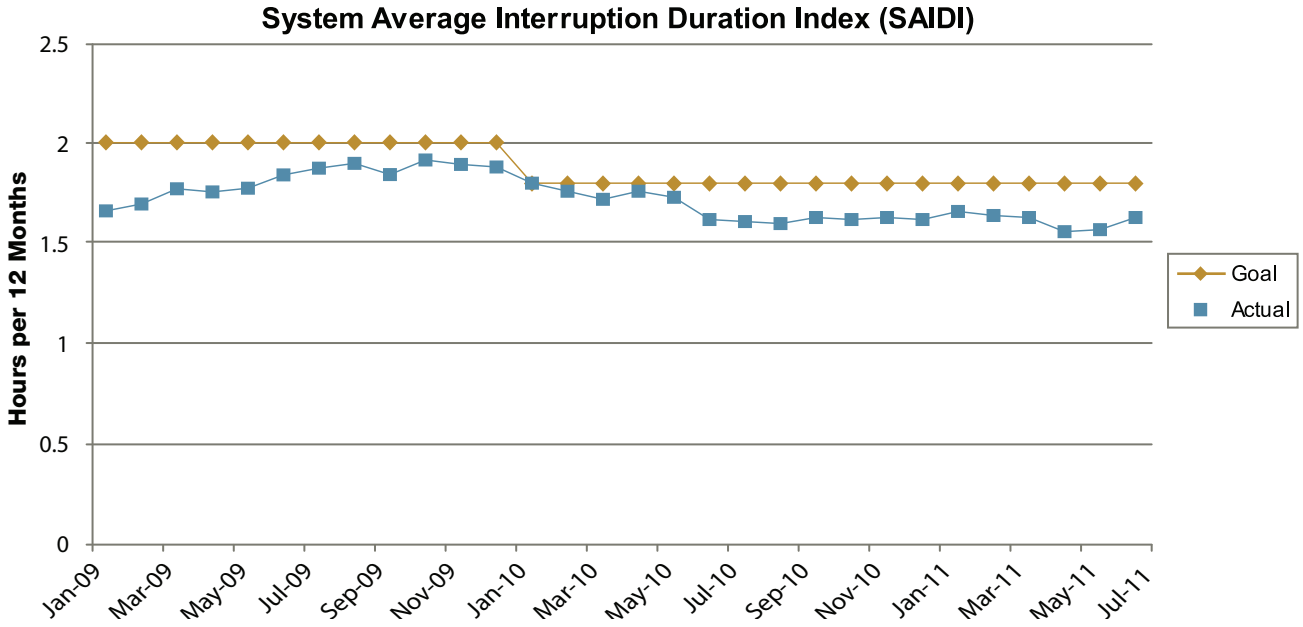
Reliability standards have been in place within the North American electric utility industry for many decades. Following recent wide spread power losses in America, such as the Northeast blackout in August 2003, the electric power industry and its regulators have reaffirmed the importance of reliable service to support the requirements 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.

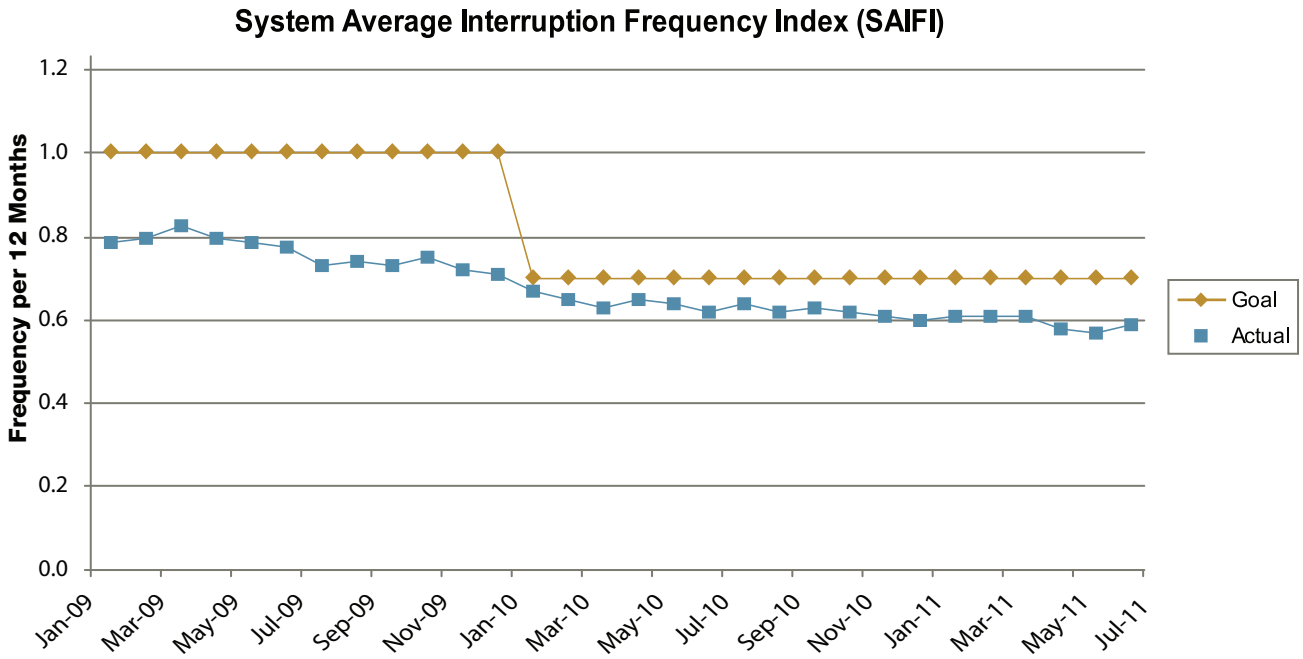
Two industry criteria generally accepted for measuring an electric system's reliability of service to its clients are the following:

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 provide perspective on the short term trend of the Authority's SAIDI and SAIFI data over the 30 month period ending on June 30, 2011. During this timeframe the average duration of service interruptions tended to stay in a relatively narrow band while the frequency of interruptions trended on a gradual downward slope. In comparison to the reliability indices of five years ago, however, the recent SAIDI and SAIFI data are less than one-half of levels in fiscal year 2006. To achieve these significant reductions in service interruptions the Authority prioritized improving the reliability of the distribution system. A critical component in the Authority's program was to re-establish emphasis on tree trimming and vegetation control programs that specifically address a major cause of service interruptions. The scope of the Authority's on-going program includes both transmission and distribution lines, as well as public education of appropriate plantings located under overhead power lines. Concurrent with these programs the Authority established lower performance goals, which have been progressively dropped as they have been met. The most recent reduction in January 2010 lowered the target SAIDI by 10% and SAIFI by 30% to reflect the Authority's objectives in continuing to improve client service.

As the Authority's SAIDI and SAIFI goals have dropped and become more challenging to achieve and maintain, 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 continued a trend from fiscal year 2009 indicating that additional significant reductions in the average duration of interruptions may be difficult to achieve in the near term.

During fiscal year 2011 the twelve-month rolling average of the number of sustained outages per client slowly declined and was below the Authority's SAIFI goals for the year. Similar to the SAIDI statistics discussed above, fiscal year 2011 continued a downward trend in the frequency of interruptions from 2009 that may be difficult to extend beyond the near term.

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 proposed, improved automated systems and Automated Meter Reading 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.

TECHNOLOGICAL SYSTEMS OPERATIONS

The Authority employs numerous automated control systems to ensure safe and reliable operation of its System. These systems coordinate with or are integrated into larger systems that support the Authority's routine technical and commercial operations. This section addresses selected automated systems employed by the Authority for control and operation of the generation, transmission and distribution systems.

ENERGY MANAGEMENT SYSTEM

Consistent with good operating practice in the industry the Authority uses a sophisticated control system to regulate operation of its production sources to always match in real time the consumption of electric power while maintaining the proper voltage and frequency.

The Authority's present energy management system (EMS) has been in service since 1999. When it was installed the EMS was basically a second generation of the digital control systems used for control of electric transmission and generation systems. Early in fiscal year 2010 the Authority contracted for the replacement of the EMS. The vendor of the latest generation EMS had supplied and supported the present system; this facilitated the design of the new EMS to meet the Authority's requirements and operator interface. Although the present EMS continues to function properly with the existing System, the EMS hardware and software are aging. In addition, the EMS is not configured to handle the operation of a System that will include intermittent renewable energy generation and wheeling mandated by recent Commonwealth legislation. The new EMS will also update the Authority's cyber-security system for compliance with North America Electric Reliability Council's (NERC), critical infrastructure protection (CIP) standards. Approximately one half of the funding of the replacement EMS was obtained through the U.S. Department of Energy's "Recovery Act Smart Grid Investment Grant Program". The new EMS can interface with the distribution management system, which is an important communications link for "Smart Grid" technologies.

In conjunction with the new generation EMS, over the last three years the Authority has been upgrading the supervisory control and data acquisition (SCADA) system functionality. The SCADA system is the secure communications network linking the central EMS with all the generation sources and substations.

The scope of work for the new EMS includes new hardware and software. With the new EMS, the Authority's back-up control center in Ponce will be upgraded to enhance its ability to respond to critical situations if the primary control in Monacillo is limited or compromised. The EMS features include extension of the Authority's load forecasting and load flow analysis. The automatic generation control (AGC) will be based on revised economic and security criteria. Among the network applications will be power scheduling opportunities, it will provide improved software for the analysis of disturbances; phase angle and frequency monitoring and for the detection and analysis of inter-area oscillation. The replacement EMS will more accurately identify fault locations thereby facilitating faster service restoration and interface with the distribution outage management system.

During fiscal year 2011 several factory acceptance tests were completed at the vendor's facility. Since the new EMS was developed by the same vendor who supplied the present system, similarities in their architecture will facilitate the training; the operator training simulator is being configured to incorporate distributed generation and wheeling. The implementation of the new EMS is scheduled for fiscal year 2012.

ASSET MANAGEMENT SYSTEMS

During fiscal year 2011 the Authority was in the process of upgrading its programs for work and asset management systems to utilize modern platforms and provide improved service to its users.

PRODUCTION PLANT ASSET MANAGEMENT SYSTEMS

Since 2010 the Authority has been upgrading its enterprise asset management systems (AMS) program that supports its generation and high voltage assets to more effectively monitor and manage these critical assets and associated inventory with the objective of improving their reliability and availability. The present system has been in place for more than a decade and has been superceded by newer technology. The supplier of the new AMS suite of programs is a well established vendor in this field and has direct relevant experience with electric utilities; the supplier is also the successor to the present AMS vendor. The new AMS will improve the coordination of the numerous directorates with responsibility for the management of the production and high voltage electrical assets. It will facilitate the integra-

tion of data into the different programs used within the human resource, financial, engineering, procurement, and management disciplines.

The new AMS suite of programs integrates operational and support resources within the Authority to manage assets, their maintenance, repair, and overhaul costs to achieve a high level of performance, safety, and reliability. The suite addresses work and asset management through maintenance optimization, life extension, work planning, predictive failure, materials and planning, monitoring of critical equipment on a real time basis, and analysis of historical performance data to improve repair or replace decisions. Effective management of supply chain responsibilities, maintenance of critical spares, purchasing, expediting, material receipt, management of accounts payable, and quality control are each critical to the Authority's asset management program. Safety and compliance management components identify requisite safety training requirements for the work being performed, possible chemical exposures, permit requirements, document control procedures, and environmental compliance.

The data conversion from the present AMS program to the new AMS is scheduled to begin early in fiscal year 2012. System acceptance testing is scheduled for completion early in calendar year 2012. Concurrent with these activities will be training in the new AMS program. It is scheduled for initial service before the end of fiscal year 2012.

TRANSMISSION & DISTRIBUTION ASSET MANAGEMENT SYSTEMS

Presently the Transmission & Distribution operations of the Authority use a multi-faceted work and asset management system that is more than ten years old. The Authority's transmission and distribution asset 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 areas such as Finance, Human Resources, and Procurement. The objectives of the AIRe 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.

Over the last decade since the AIRe system was implemented, the applicable vendors, hardware and software technologies have evolved. During fiscal year 2011 the Authority re-evaluated various options to replace the existing AIRe software which was supplied by a vendor who was subsequently acquired by another vendor, who agreed to support the old software for only a limited time. One of the goals of the evaluation was to identify a system that provides a state of the art asset management system while maintaining the user interface with which the Authority's transmission and distribution personnel were accustomed. The AMS system discussed above for production plant asset management did not meet the criteria established for the transmission and distribution users. The new asset management system for transmission and distribution work, however, will include interfaces with the production AMS. The Authority plans the upgraded asset management system to interface with the outage management system and geographical information system with web based technology. At the end of fiscal year 2011 the Authority was planning to complete its technical and commercial negotiations with the selected vendor in fiscal year 2012; the schedule for implementation of the new system would be established then.

The work management system (WMS) component of the AIRe system has been in service in all of the Authority's districts since 2001. The WMS tracks the progress of all construction and maintenance work from start to completion. 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.

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 (OMS), 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 OMS discussed below. 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) 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.

In conjunction with the OMS system the Authority expanded the use of an automatic vehicle location (AVL) system to more than 750 vehicles during fiscal year 2011. 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 in reducing travel time to respond 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.

Since the Authority completed the installation of the work management system in each district and implemented the interface with the Customer Information System, Customer Services operators can access the WMS to provide timely information to 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.

REMOTE METER READING

In fiscal year 2000 the Authority began the island-wide installation of an automated meter reading (AMR) system. The key attribute of the new meters is the ability to remotely read the parameters measured by the meter. The scope of the AMR system will enable the Authority to remotely status the meters of all clients in residential, commercial and industrial classes. Capital expenditures for the AMR system through fiscal year 2011 were approximately $200 million, with $59 million budgeted for fiscal years 2012 through 2016. The program consists of installing new design digital meters for all new clients as well as actively replacing old and defective meters. By the end of fiscal year 2011 automated meters had been installed in more than 96% of the Authority's clients. 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 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, microwave systems or secure internet. During fiscal year 2011 the Authority completed the installation of AMR equipment at all its active substations; all new substation include the AMR equipment with the original construction.

The Authority's early experience with the AMR meters exposed weaknesses in the meter's resistance to tampering. During the first ten years of deployment the meter technology evolved from electro-mechanical meters with communication modules to rugged digital meters, fitted with the same communication module. Over the years the Authority has worked with meter vendors to develop increasingly robust units to resist tampering. It has also enhanced sealing of the plastic case of meters that were already in inventory but had not been deployed. The Authority now buys meters with the most robust anti-tampering specifications commercially available; these meters also include internal memory good for storing many months of data, which might be used if tampering or theft were suspected, or for data recovery if the AMR communications were disrupted. In fiscal year 2011 the Authority began installing meters with an integral connect/disconnect feature. These meters have greatly reduced the time required for customer service connections and disconnects for short term clients or in problematic locations. In most instances these meters enable a client to re-establish disconnected service after making a secure payment of an overdue invoice by phone or internet within minutes of that payment.

During fiscal year 2011 the Authority continued its aggressive 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, unannounced meter inspections, and a toll free hot line for anonymous reporting of suspect electricity theft. Based on recent experience, 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 culpable clients.

As the technology for remote meter reading has evolved the Authority has identified certain applications which may benefit from enhanced access to the client meter data. The Authority is evaluating a new meter data management system to facilitate the data exchange with the new client billing system the Authority plans to implement in the next fiscal year. The meter data management system may also be used for enhanced data input to the OMS discussed above. The Authority is also evaluating using the AMR system to provide data to support the upgraded EMS, discussed above, which will be the principal system for controlling the generation and transmission of power on the island. The electrical power consumption data could also be used to support analyses of operational performance and time based pricing structures that may be evaluated in the future.

The Authority plans to upgrade the AMR communication equipment at its large substations to improve data transfer speed. In addition, the Authority plans to install internet communication with the AMR communication gear at many of its substations to improve reliability and provide operational flexibility.

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. This two-way communications is a critical attribute of the "Smart Grid". 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 the 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; refer to the *Demand and Energy Forecast* section.

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 2011 amounted to $36.1 million. The actual expenditures during fiscal year 2011 were $41.0 million, of which $3.6 million were expended on General Land and Buildings. The budget over-run was principally attributable to the costs of computer equipment associated with the new Client Services system which is scheduled to be in service in fiscal year 2012. As shown on *Appendix X Details of Capital Improvement Program,* the expenditures for General Plant for fiscal years 2012 through 2016 are forecasted to be $55.0 million, $36.5 million, $40.5 million, $36.1 million, and $29.2 million, respectively.

The extensions and improvements planned for fiscal year 2012 include $18.8 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 largest budget item in this group is the rehabilitation of the Authority's former headquarters building in Santurce, San Juan, which is still used for administrative services. The $12.9 million project is scheduled for completion by the end of fiscal year 2013. As discussed in the *Production Plant* section above, the Capital Improvement Program for fiscal year 2012 also includes building improvements at various generating plants, such as an elevator at the Costa Sur Steam Plant.

The total expenditures for Equipment in fiscal year 2011 were $37.5 million. For fiscal year 2012 the total Equipment budget is $36.3 million; this is comprised of four budget subgroups, as follows: The Computer Equipment budget for fiscal year 2012 is $23.5 million. The largest project is $20.0 million allocated to support the extensive Client Service systems upgrade. The Transportation Equipment budget is for repairs or improvements to the Authority's aircraft and for purchase and replacement of the Authority's vehicles; the budget for fiscal year 2012 is $8.4 million. The Communication Equipment budget is $400,000 for fiscal year 2012. The last Equipment subgroup is Other Equipment, which has a budget of $3.7 million for fiscal year 2012. The scope of this subgroup spans a wide range of equipment including miscellaneous tools used for the installation of transmission and distribution lines, environmental monitoring equipment, specialized power quality monitoring equipment, vehicle repairs tools, and small construction tools.

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 2011 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 three hundred and eighty 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.

CURRENT FORECAST

During the fourth quarter of every fiscal year the Authority develops a forecast entitled *Presupuesto de Ingresos* (Revenue Budget) that develops total energy sales, energy sales by service class, revenues, number of clients, generation, annual peak demand and projected fuel costs. These financial projections are essential input to the Annual Budget, as well as for future financial planning and capacity planning. This annual report references the Authority's Presupuesto de Ingresos (Revenue Budget) as the "Current Forecast". The Current Forecast contains detailed short to intermediate- term projections of energy sales revenues, number of clients, and fuel prices based on Energy Information Agency (EIA) projections and other sources; the forecast also includes long-term generation and long-term peak demand. 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 initial year of the short-term financial projection is used for the Authority's Annual Budget of Current Expenses (Annual Budget) for the ensuing fiscal year. The short to intermediate- term energy projections are utilized to establish the Authority's needs for capital expansion and the projected sales revenues, which are used to project its ability to meet the necessary requirements of the 1974 Agreement covenants regarding net revenues to projected debt service. The long-term peak demand and generation projection through fiscal year 2040 are generally used for trends of generating capacity that may be needed in the future. (See *Capacity and Energy Resource Planning*)

The Authority developed a Current Forecast dated May 2011 as the basis for the fiscal year 2012 budget, projections through fiscal year 2016 and long-term projections through 2040. In December 2012 the Authority updated its forecasts for fiscal year 2012 and extended its intermediate-term projections through fiscal year 2017. We refer to the forecast developed in December as the "Revised Current Forecast".

To establish energy sales data for fiscal year 2011, which is the base year in the May 2011 Current Forecast, the Authority's Planning Directorate used actual energy sales from July 2010 through February 2011 and preliminary generation data for March 2011. The estimate for energy sales for the remaining months of fiscal year 2011 were extrapolated from generation data for the comparable months in the five year period ending in fiscal year 2010, while sales by service class were estimated to follow the average distribution of the 12 month through February 2011. The projections for energy sales and related data for the period of fiscal year 2012 and after were based on econometric modeling of energy sales by service class. Macroeconomic indicators provided by economic consultants are key dependent variables for these models. The Authority also has extrapolations of energy sales by service class based on monthly data since fiscal year 1993 and annual data since 1983. 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 sales, revenues, number of clients, generation, and maximum demand on a monthly basis for the remainder of fiscal year 2011 and for all of fiscal year 2012 and on an annual basis thereafter through fiscal year 2016. Projections of fuel costs are also provided through fiscal year 2016. The long-range forecast projects annual generation (in GWh) and peak demand (in MW) through fiscal year 2040.

The projected revenues in the Current Forecast are derived from the forecast energy sales by classification using existing base rates and the appropriate projected adjustment charges for the cost of fuel and purchased power. The Current Forecast also includes

projections for the reductions due to subsidies and credits applied to the fuel and purchased power revenues and the hotel subsidy, but these reductions are not incorporated in the total revenue forecasts. 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. For the May 2011 Current Forecast the three consultants were: the Inter-American University – IHS Global Insight (IAU-GI); the Commonwealth of Puerto Rico's Planning Board (Planning Board) and Advantage Business Consulting (ABC). Last year the Authority chose ABC to replace a longtime consultant, Econometrica, who is no longer in operation.

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 capacity and operational planning. For the Current Forecast the Authority selected the ABC projections for its financial forecast of its annual budget for fiscal years 2012 through 2016; the average electric sales growth rate based on ABC projections was -0.38%, while the Planning Board projections resulted in 0.46% and IAU-GI was 0.50%. (See *Econometric Factors* section below.) The most expansive projections, that of IAU-GI, were used in its load growth forecast for capacity planning.

For many years the short-term energy sales projections in the Authority's Current Forecasts were usually 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 its projections, in 2008 the Authority revised the modeling of residential and industrial class consumption to reflect the clients' sensitivity to the price of electricity.

In the second quarter of fiscal year 2012 the Authority developed a revised forecast of energy sales and fuel pricing, which were the bases for its projections which we refer to as the "Revised Current Forecast". The methodology used for the Revised Current Forecast followed that described for the Current Forecast. The scope of this forecast addressed the balance of fiscal year 2012 and the intermediate-term through fiscal year 2017; the long-term expansive projections from the Current Forecast were not revised since the forecasted growth was low and will be reviewed again for the next *Presupuesto de Ingresos* (Revenue Budget) to be developed later in fiscal year 2012. The Revised Current Forecast was based on actual data from fiscal year 2011 and the first four months of fiscal year 2012; during these four months total energy sales dropped 3.0% in comparison to a decline of 1.8% for the same period in the previous year.

The largest revisions in developing the Revised Current Forecast over the Current Forecast involved updating the projected costs of fuel and to show natural gas firing at only Costa Sur Units 5 & 6 through the forecast period. These two were the only units in the Authority's system which were both capable of firing natural gas and reliably scheduled to be supplied with gas beginning late in fiscal year 2012, since the regasification expansion work at EcoEléctrica was nearing completion when the Revised Current Forecast was developed. The Authority's ongoing plans include fuel conversion to gas firing at many units, however the scope and schedules for supplying natural gas to these units were not firm when the Revised Current Forecast was prepared.

The Revised Current Forecast was updated with forecasts from ABC and IAU-GI, as of October 2011, however updated forecasts from the Planning Board were not available. The consultant's projections differed slightly on the performance of GNP for fiscal year 2011; ABC estimated that the economy as measured by GNP in fiscal year 2011 had decreased by 1.91% whereas IAU-GI had the economy receding by 0.81%.The revisions to the GNP forecasts over the five year period showed an average annual increase in the GNP of 0.97% for ABC in comparison to the earlier forecast of 1.25%, while IAU-GI changed from 1.44% to 1.28% in the October 2011 projections.

In the Revised Current Forecast the updated econometric factors only marginally affected energy sales forecasts over the intermediate-term period. The least expansive projection in the Revised Current Forecast was based on ABC's model, with the results that the average annual electric sales growth over the five years of 2012 through 2016 increased from negative 0.38% in the Current Forecast to negative 0.26% in the Revised Current Forecast. The updated IAU-GI forecast projected an annual average growth rate of electric sales of 0.36% through 2016, while the earlier model resulted in 0.50% growth rate.

ECONOMY OF PUERTO RICO

Since the present depressed state of the economy of Puerto Rico is unprecedented in recent history, 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.

According the Puerto Rico Government Development Bank using fiscal year 2010 data, the composition of the Puerto Rico Gross Domestic Product (GDP) by sector is as follows: manufacturing 46.3%; finance, insurance, and real estate 19.5%; services 12.4%; government 8.6%; trade 8.0%; transportation and utilities 2.9%; construction and mining 1.7%; and agriculture 0.6%.

The Planning Board is the official Commonwealth agency that collects and reports the macroeconomic indicators utilized in the Current Forecast, including the Gross Domestic Product (GDP), and the Gross National Product (GNP), of the Puerto Rico economy. 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 1.2% in fiscal year 2007, 2.8% in fiscal year 2008, 4.0% in 2009, 3.8% in 2010, and 1.0% in 2011. For the five-year period from 2007 to 2011 the contraction in Puerto Rico's GDP totaled over 12%, a magnitude not seen since the Great Depression. For fiscal year 2012 the Planning Board projects a marginal growth rate of 0.7%.

The following chart shows the projections of the Gross National Product for Puerto Rico by the Authority's three economic consultants for fiscal years 2010 through 2016. The forecasts by ABC and IAU-GI are as of October 2011, the forecast by the Planning Board is as of May 2011. As shown below there is little difference in the three forecasts resulting in a five-year compound annual growth rates of: ABC 0.97%, IAU-GI 1.28% and the Planning Board's 1.27%.

Year	ABC	Percent Change	IAU-GI	Percent Change	Planning Board	Percent Change
2010	6,255.1	-3.77%	6,255.1	-3.77%	6,255.1	-3.77%
2011	6,135.6	-1.91%	6,204.4	-0.81%	6,195.0	-0.96%
2012	6,080.4	-0.90%	6,222.4	0.29%	6,239.0	0.71%
2013	6,110.8	0.50%	6,261.6	0.63%	6,320.0	1.30%
2014	6,226.9	1.90%	6,378.1	1.86%	6,405.0	1.34%
2015	6,328.2	1.63%	6,500.6	1.92%	6,501.0	1.50%
2016	6,437.7	1.73%	6,610.4	1.69%	6,599.0	1.51%

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 historical and projected macroeconomic indicators. These macroeconomic indicators are: personal disposable income, used in part to forecast residential energy sales; GDP, used in part to forecast commercial energy sales; and GNP, used as a factor in forecasting industrial energy sales.

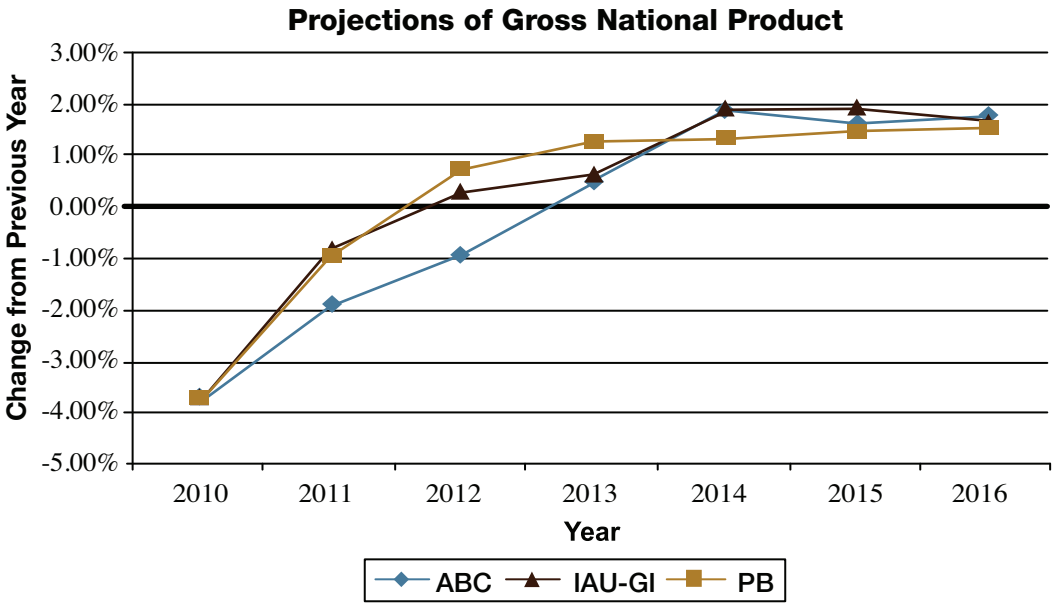
In developing the Current Forecast and the Revised Current Forecast the Authority uniformly employs the economic indicators from each economic consultant. The resulting energy sales over the five-year intermediate term forecast period are summarized below (CAGR is the compound annual growth rate), with ABC and IAU-GI data from the Revised Current Forecast:

TOTAL GWH SALES PROJECTIONS

Fiscal Year	ABC	Year Change	IAU-GI	Year Change
2011	18,501.4	-3.81%	18,501.4	-3.81%
2012	17,940.2	-3.03%	18,095.8	-2.19%
2013	17,741.1	-1.11%	18,006.9	-0.49%
2014	17,797.3	0.32%	18,158.5	0.84%
2015	17,987.5	1.07%	18,460.2	1.66%
2016	18,261.6	1.52%	18,840.9	2.06%
	5-year CAGR	-0.26%		0.36%

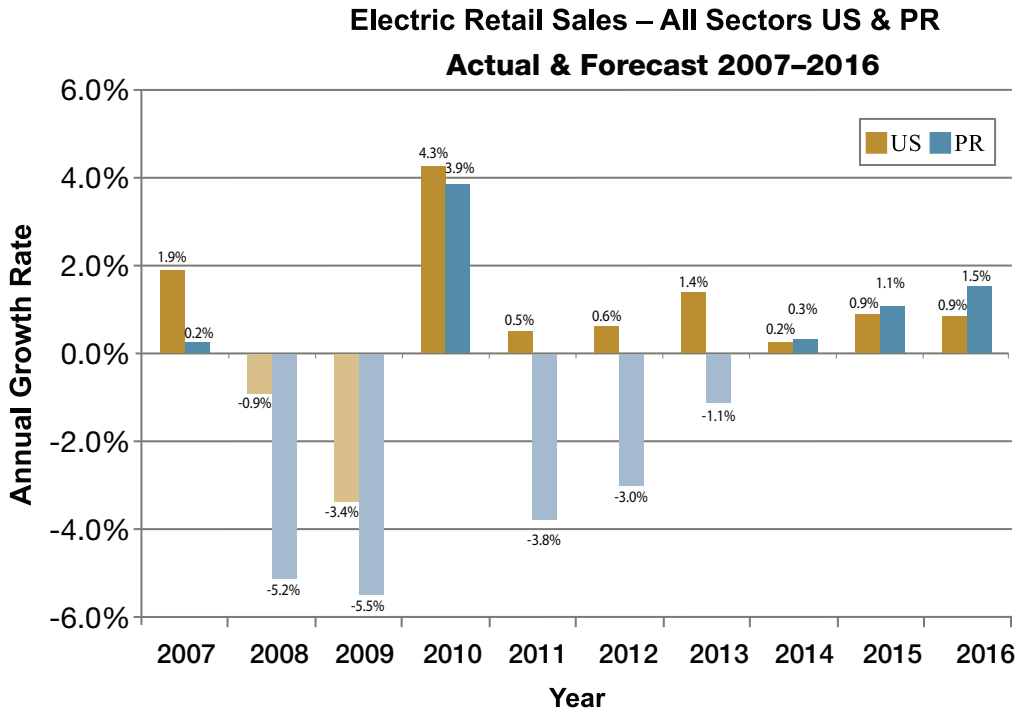
Revised Current Forecast, 2011 Actual

For reference, ABC considered a wide range of factors while developing its economic forecast dated October 2011 over the forecast period. As reported in the Revised Current Forecast, these factors included the following exogenous variables: growth of the U.S economy of between 1.8% and 3.1%,; the price of a barrel of oil (WTI) of between $85 and $86; U.S. interest rates for Certificates of Deposit of between 1.0% to 3.6% and commercial notes of between 2.7% to 5.5%. The endogenous variables considered are: the Commonwealth government will meet projected revenue and expenses and will not need to increase measures of austerity, the end of the American Recovery & Reinvestment Act (ARRA) Fund, liquidation of the Jobs Act, changes in the pharmaceutical sector including the expiration of patents that can cause reductions in production of 25% to 30% and the effect of the 4% surcharge to non-resident corporations can aggravate the effect of patent expiration, the Commonwealth Government will not incur additional expenses with the reformation of the Government Health and Pension System and collective bargaining negotiations.



CONSUMPTION OF ELECTRICITY

Over the period 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 energy 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. In fiscal year 2010, the negative trend in energy sales reversed when total energy sales increased by 3.9%, principally as a result of greater energy sales of 10.8% in the residential sector. However, during fiscal year 2011 energy sales declined by 3.8% continuing its previous negative trend.



The five-year energy sales projection in the Current Forecast showed declining annual energy sales of 2.8% and 1.4% for fiscal years 2012 and 2013, respectively, and incremental positive growth of 0.1%, 0.7%, and 1.3% in fiscal years 2014 through 2016, respectively. The Revised Current Forecast resulted in a similar pattern with declines of 3.0% and 1.1% in fiscal year 2012 and 2013, followed by growth of 0.3%, 1.1% and 1.5% for fiscal years 2014 through 2016. As shown on the comparative chart below, Electric Retail Sales-All Sectors US & PR, the rate of growth in electric sales has gradually decreased over the past five years in Puerto Rico as it has on the U.S. mainland.

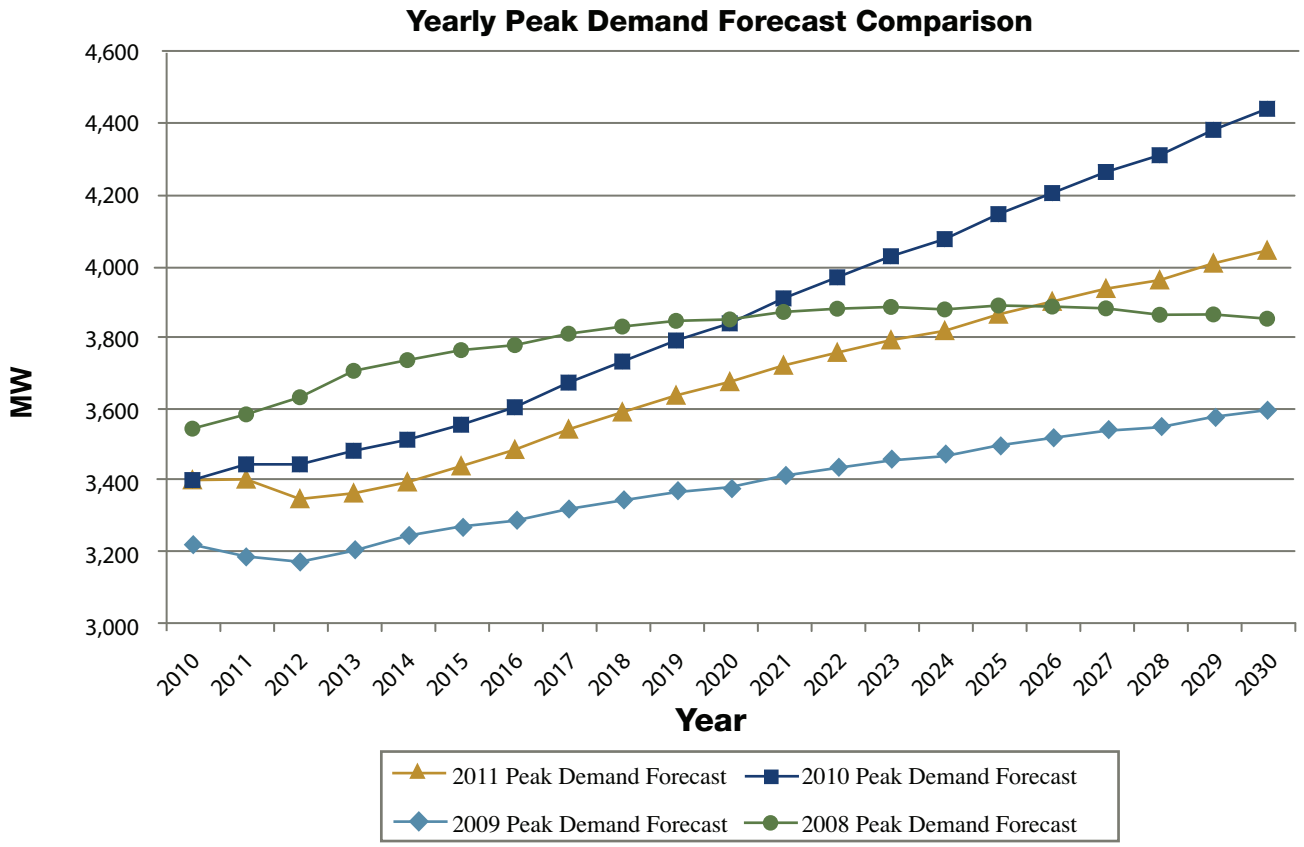
U.S. energy sales dropped 0.9% and 5.2% in calendar years 2008 and 2009, respectively, and reversed that negative trend in calendar year 2010 to increase 4.3%. For calendar years 2011-2016 the EIA forecasts US energy sales to grow marginally. The data for the U.S. are derived from monthly and annual EIA sources. The first EIA report is the Short-Term Energy Outlook, which is published on a monthly basis and is therefore current; this was referenced for the historic data and the forecast for the calendar year 2010. Data for 2011 and 2012 were taken from the January 2012 *Short-Term Energy Outlook*. The EIA's *Annual Energy Outlook 2011*, prepared in April 2011, was the source for the forecast data in calendar years 2013 through 2016.

DEMAND AND ENERGY FORECAST

GENERATION FORECAST

The total net generation for fiscal year 2011, including purchased power and hydro-power, was 21,639.7 GWh, which was a 4.1% decrease compared to that generated in fiscal year 2010. This decline in generation exceeded the outlook of last year's Current Forecast which had forecasted a decline in generation of 3.4% in fiscal year 2011. The decline in net generation was the third in the past four years and is approximately equivalent to the net generation in fiscal year 2002. For the five-year period from fiscal year 2006 through 2011, the compound annual growth rate (CAGR) in net generation was negative 1.9%. The Revised Current Forecast of electric generation over the next five fiscal years, through 2016, tracks with forecasted sales and has a CAGR of negative 0.3%. In the Current Forecast, the long-term generation forecast for the following ten years through fiscal year 2026 projects small but steady annual increases with a CAGR of 1.0% in that period.

The Current Forecast and Revised Current Forecast developed 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 projections in the Revised Current Forecast were based on actual generation data for fiscal year 2011 and the four months through October 2011 and projected for the remaining months of the fiscal year. The annual generation for the forecast period was determined utilizing a system efficiency that was the System's annual average for fiscal year 2011, based on the sales and generation data methodology in the Revised Current Forecast.

PEAK DEMAND FORECAST

Consistent with the Authority's conservative approach to expansion of generation capacity the Current Forecast used the projections that resulted in the most expansive forecast for the development of the peak demand forecast. In May 2011 the projections from IAU-GI were the basis of the peak demand forecast. In the Revised Current Forecast the projections from IAU-GI were more expansive than ABC, but marginally lower than the earlier IAU-GI forecasts. To be conservative, the peak demand forecast in this section is based on IAU-GI projections in the Current Forecast.

For the fifth 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 2006 to 2011 the five-year CAGR in actual peak demand contracted by 1.6%. The peak demand for fiscal year 2011 was 3,406 MW which is 2 MW greater than that the peak demand reached during fiscal year 2010 and 7.6% less than the historic system peak demand. The Current Forecast utilized a system load factor of 75.92% to project peak demand for the duration of the generation forecast. The system load factor is the ratio of the average demand in kilowatts supplied during a designated period, in this case the twelve months through March 2011, 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 until fiscal year 2020. The forecast peak demand projects a CAGR growth of 0.6% during the five-year period from fiscal year 2011 through 2016; 1.0% growth over the ten-year period from fiscal year 2011 through 2021; and, 0.9% over the long-term forecast to 2040.

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 Yearly Peak Demand Forecast Comparison graph shows the degree in which the peak demand forecast has changed over the last four 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 shift load from peak hours to nonpeak 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.

The Commonwealth Government's Energy Affairs Administration (EAA) launched a public service campaign entitled "Conserving energy: the best idea" to create awareness on energy savings early in fiscal year 2011 to advocate simple and practical advice for energy savings such as replacing incandescent light bulbs with compact fluorescent bulbs and switching appliances off when not in use. This program was a continuation of other Commonwealth programs to encourage reduction in energy consumption.

Also during fiscal 2011 the EAA launched the State Energy Efficiency Appliance Rebate Program. This Program offers a $200 voucher for the purchase of new energy efficient appliances, such as refrigerators, laundry washers, dishwashers, air conditioners and electric heaters thereby replacing old less efficient

appliances. As of mid-December 2010 approximately one thousand vouchers had been issued

During fiscal year 2010 the Commonwealth government offered incentives to the municipalities with funds received from the Federal American Recovery and Reinvestment Act (ARRA) to modify their electric consumption with more efficient lighting and appliances. One of these incentives begun in fiscal year 2011 was the State Energy Efficiency Appliance Rebate Program. This Program offers a $200 voucher for the purchase of new energy efficient appliances, such as refrigerators, laundry washers, dishwashers, air conditioners and electric heaters thereby replacing old less efficient appliances. As of mid-December 2010 approximately one thousand vouchers had been issued.

The Federal ARRA funding was directed to commercial energy efficiency projects, projects to increase job growth, and increase investment in companies that develop energy saving technologies. Included in the funding targets were building energy audits; energy efficiency retrofits, developing and implementing transportation programs, and other purposes. The initiative's goal was to achieve an annual minimum target in electricity savings of 1 percent. ARRA funding supported the installation of more than 2,100 light emitting diodes (LEDs) by the Department of Transportation and Public Works in March 2011. The LEDs are expected to reduce energy costs by 70 percent in addition to savings in other maintenance related costs, with the projected savings of $300,000.

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. The Authority is evaluating its long term metering plans to potentially expand the operational features of its automated meter reading system to include a load control component. This feature would increase the impact of load reduction by allowing the Authority to control clients' equipment, such as air conditioners, for periods when load management is desirable.

CAPACITY AND ENERGY RESOURCE 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.

The Authority's goals of providing low cost and environmentally compliant electric power are the cornerstones of its energy resource planning. To these ends the Authority has pursued fuel diversification for many years, with the primary focus being on increasing the utilization of natural gas in its production plants. As renewable energy technologies have matured and been supported by legislation, they have entered the Authority's near term forecast mix of electric power sources.

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 lowered 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

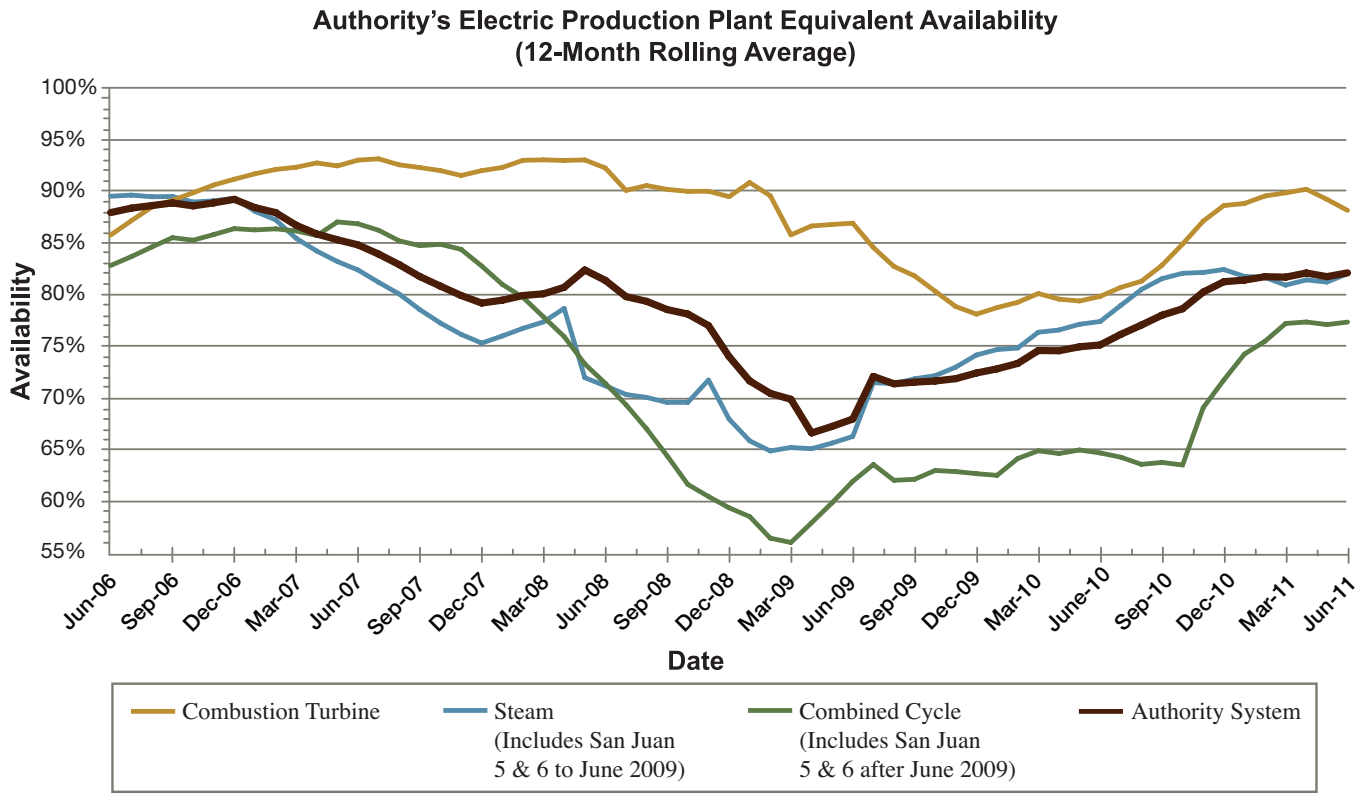
being consistently in the range of 80% up to 2003, to 88% by the end of calendar year 2006. In the most recent five years the Authority's system availability was negatively impacted by three notable events. The most significant was the extended loss of 602 MW at the Palo Seco Steam Plant as the result of two separate fires on December 29 and 30, 2006. The second was equipment failures shortly after the start up at the combined cycle San Juan Units 5 & 6 and, to a lesser degree, the third was the modifications of the Aguirre Combined Cycle units to add natural gas firing capability. The loss of capacity at Palo Seco and San Juan stations reduced the Authority's twelve month average steam plant availability from a peak of 89% in December 2006 to 72% at the end of fiscal year 2009. During fiscal year 2010 the Palo Seco units were fully restored to service. The availabilities of both the steam plant and total system steadily increased during fiscal years 2010 and 2011. Steam plant and total system availability were slightly above 82% at the end of fiscal year 2011. The Authority anticipates continued availability in this range through fiscal year 2013 during the completion of scheduled major overhauls of large steam units and the conversion of the San Juan Combined Cycle to dual fuel firing capability. After 2013, system availability is forecasted to increase to approximately 85%.

The Authority's overall production plant equivalent availability for the five-year period ending June 30, 2011 is shown in the chart based on rolling twelve month data. Performance is shown by the Authority's total system and by the three major kinds of generation—steam, combustion turbine, and combined cycle. Prior to fiscal year 2010, the availability of San Juan Units 5 & 6 was included with the steam portion of the system. Beginning in fiscal year 2010 San Juan Units 5 & 6 were tracked in the combined cycle group.

CAPACITY PLANNING

The Authority's current capacity expansion plan is based on the Authority's most recent Current Forecast dated April 2011. As discussed in the *Demand and Energy Forecast* section, the Current Forecast foresees relatively steady, but modest increases, in peak demand averaging 0.9% per annum over the first ten years of the forecast period. The previous system peak of 3,685 MW, established in fiscal year 2006, is not currently forecasted to be exceeded until fiscal year 2020, beyond the horizon of the Authority's capacity planning.

Details of existing generating capacity of the System are shown in *Appendix VIII, System Capability.* The Authority does not plan to add or retire existing capacity through fiscal year 2016. In view of the low capacity factor associated with most renewable energy projects discussed below, their additions to the system are recognized as energy sources, however for system operation the Authority will not rely on these projects for dependable capacity.



PURCHASED POWER

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

In accordance with a 22-year power purchase operating agreement (PPOA) that commenced in March 2000, the Authority began purchasing 507 MW of power produced by EcoEléctrica, L.P.'s gas-fired combined-cycle cogeneration facility. The PPOA 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 availability during fiscal year 2010 was 90%, but improved to 94% in fiscal year 2011.

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 coal-burning technology. The facility commenced commercial operation in November 2002. The 25-year PPOA 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. The availability of AES-PR for the 12 months ended June 30, 2010 was 82%; actual availability for fiscal year 2011 was 89%.

These PPOA'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 Operation* 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. Based on the past fiscal year's sales, it is estimated that more than 35% of the Authority's annual energy sales could be derived from fuels other than oil, if both the EcoEléctrica, L.P. and AES-PR plants were operating at base load. In fiscal year 2011 the cogenerator generation was 32.8% of the system total. Subject to dispatch and actual availability, the combined generation of EcoEléctrica, L.P. and AES-PR is forecasted to be 32.1% of the total System generation in fiscal year 2012.

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 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 afford the Authority the opportunity to better dispatch its electric production plant.

ENERGY RESOURCE PLANNING

With the prospect of adequate generation reserves for many years the Authority has moved to focus on reducing and stabilizing future electric power costs by decreasing its dependence on oil. The Authority has identified the first step in this process is to expand its use of natural gas, which would be supplied to the island as liquefied natural gas (LNG). Typically the price structure of LNG tends to provide more stable energy prices in comparison to oil. The availability of competing, alternative fuels may also benefit the Authority in its negotiations with fuel suppliers. In addition, emissions when firing natural gas will be lower than with petroleum. As discussed in *Environmental* in the *System's Operations* section, pending air emission regulations will require the Authority to either install pollution abatement equipment for its residual oil fired units or significantly increase the utilization of natural gas.

In anticipation of increased use of natural gas the Authority leased excess LNG storage at EcoEléctrica's cogeneration plant in Guayanilla. The first units scheduled to use the surplus gas capacity from EcoEléctrica were the two existing 296 MW combined cycle units at the Aguirre plant, which had been converted to dual fuel capability. The pipeline project from Guayanilla to Aguirre was canceled in April 2009, however, in response to community opposition.

After cancellation of the southern pipeline to Aguirre the Authority decided to utilize the excess gas storage capacity at EcoEléctrica by converting the boilers at Costa Sur Units 5 & 6 to dual fuel. The scope of this project at the two 410 MW units is described in the *Production Plant* section of *System's Operations.* These units were selected because of their proximity to the LNG facility and the relatively low capital cost

and short schedule to convert the units to dual fuel. The conversions were completed in the third quarter of fiscal year 2011. As discussed in the *Cogenerators* section of *System's Operation,* in order to have sufficient capacity for both its needs and Cost Sur Units 5 & 6, the regasification facility at EcoEléctrica was in the process of being doubled during fiscal year 2011, with full operation targeted by the end of fiscal year 2012. Until the scope of the natural gas infrastructure is expanded beyond this stage, the two Costa Sur units will be the only Authority owned production plants with the ability to fire natural gas.

Subsequent increase in natural gas firing within the Authority's system will require a significant expansion of supporting infrastructure. The Authority evaluated a variety of gas supply and distribution alternatives. In addition to an underground pipeline originating from an LNG regasification facility on the south coast, alternatives included offshore regasification of LNG in dedicated ships, barges and offshore compressed natural gas. While the offshore delivery alternatives were technically feasible, based on its evaluations the Authority decided to pursue the expansion of the existing LNG facility in Guayanilla on the south coast, which would supply a 92 mile underground pipeline transporting gas north to generating units at Cambalache and eastward to the units at Palo Seco and San Juan. The proposed pipeline infrastructure would supply natural gas to approximately 1,520 MW of the Authority's capacity at major generating stations in the north which would be converted to dual fuel; including the capacity at Costa Sur Units 5 & 6, the Authority's total capacity with dual fuel firing capability would be 2,340 MW. By the end of fiscal year 2011 the Authority had received almost all permits for the project from relevant regulatory agencies, with the key exception being the US Army Corps of Engineers (USACE). That essential determination was expected by the end of the calendar year 2011, but as the review schedule extended opposition to the pipeline project grew on the island.

In the past fiscal year the Authority reevaluated a dedicated offshore LNG supply arrangement for the Aguirre plant on the south coast. The evaluation of the structure and costs of this configuration was still in progress at the end of the year.

In addition to the air emission benefits, the comparative cost of residual oil versus LNG sourced natural gas currently favors natural gas, therefore the dual fuel conversion of residual oil burning steam plant boilers provides some economic benefits. Greater reductions in the system generating costs, however, will be realized by natural gas firing at the newer, high efficiency units that currently use expensive distillate fuel oil, in particular the combined cycle San Juan Units 5 and 6. The use of natural gas in these units would reduce their generating costs to the lowest of the Authority's plants, thereby increasing their generation and displacing more expensive generating units, leading to a greater overall reduction in electric energy costs.

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.

To promote the use of renewable resources for the production of electric energy and further expand energy diversification, the Commonwealth passed legislation that established new initiatives to strongly encourage the development and implementation of renewable energy sources in Puerto Rico. The legislation effectively sets a target renewable portfolio standard that requires an increasing percentage of retail electric power be provided from renewable energy sources. The initial target calls for 12% renewable energy production by the year 2015, increasing to 15% by 2020 and 20% by 2035. The legislation creates a financial incentive to meet these standards by establishing Renewable Energy Certificates that can be sold if the standards are exceeded or must be purchased if the standard is not met.

The Authority plans to install two wind turbines at 1.3 MW to gain operating experience with the technology. The first turbine is slated for installation near San Juan during fiscal year 2012, while the second is planned for the island's southeast in fiscal year 2013.

As of the end of fiscal year 2011 the Authority had signed a total of 37 Agreements to Purchase energy from 982 MW of proposed renewable energy projects. The Authority has forecasted an aggressive completion schedule for these projects over the five fiscal years through 2016. As the projects become available, they are projected to produce from 3% of the Authority's total system energy in fiscal year 2013 to 8% in fiscal year 2015, when the first renewable portfolio target of 12% is proposed, and 10% in fiscal year 2016. The 37 agreements include: 394 MW of wind energy from ten proposed wind farm projects, 243 MW from six proposed waste to energy projects, 18 MW from nine proposed landfill gas projects, and 327 MW from twelve proposed solar projects. These projects depend to varying degrees on government subsidies that expire or

need to be renewed periodically. The power purchase contracts also call for the developers to post a development fee to maintain the agreement terms.

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's mix of generation by fuel type for fiscal year 2011 consisted of 66.6%, being oil generated, 0.6% from its hydroelectric plants, 16.6%, from EcoEléctrica's natural gas burning facility and 16.2%, from AES's coal burning facility.

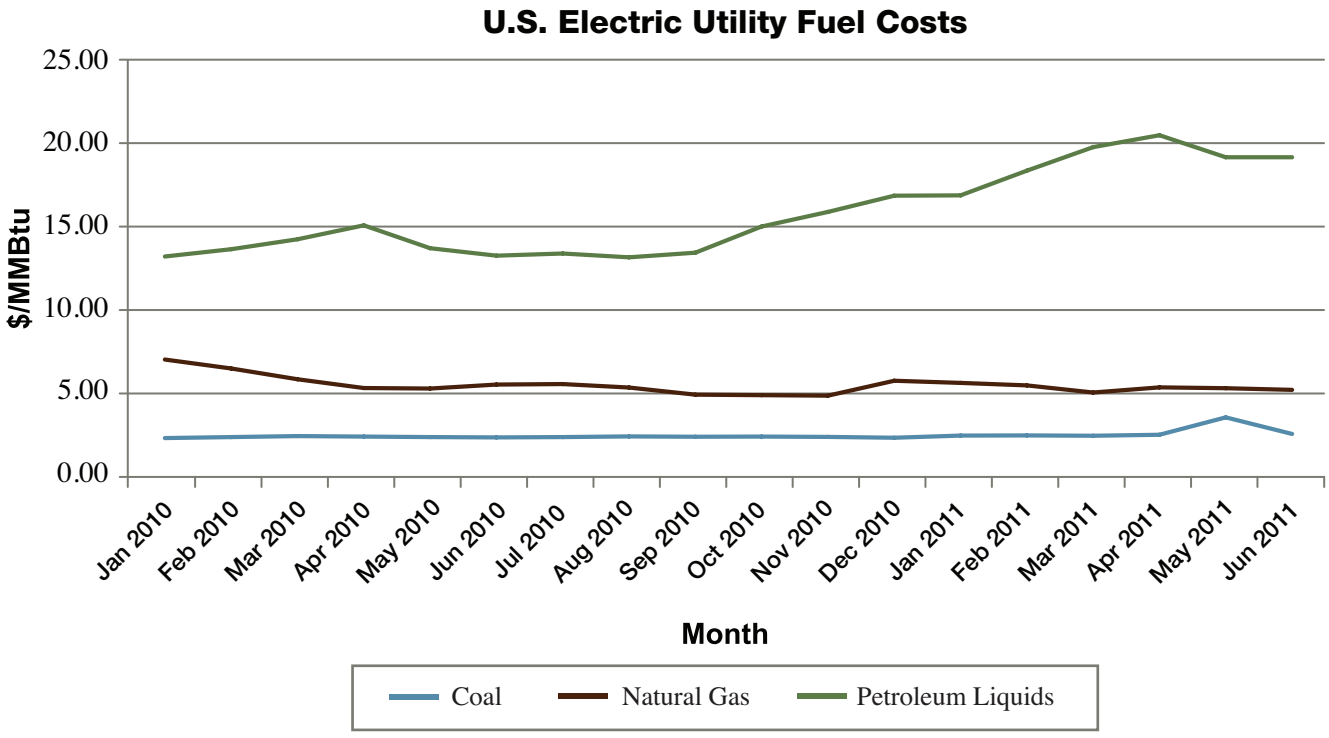
The Authority purchases all its fuel oil under one-year contracts that include an option for a second year. These contracts are structured to reflect physical clearing prices, and avoid speculation in the market. In addition, the pricing structures of the two cogenerators are based in part on annual 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—residual or distillate oils or natural gas from fiscal year 2012 and later—is based on generation required to meet the energy demand forecasts which are developed as reviewed in the *Current Forecast* section. 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 2011 and summarized annually for the five-year intermediate-term forecast. The actual annual results of generation, fuel use and costs for fiscal year 2011 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 price variations from January 2010 to June 2011 in the cost 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. This differential in price would be due to the high capital costs of infrastructure to liquefy, store and regasify the LNG, specialized transportation vessels and energy consumed in its liquefaction, transportation, storage and regasification.

AUTHORITY'S FUEL

The Authority's average composite cost of fuel oil, including transportation and fuel-handling costs and



the cost of the fuel line of credit, in fiscal year 2011 was $95.91 per barrel. The composite barrel cost is based on the total cost of all the petroleum burned by the Authority, both distillate and residual oils. The total costs of fuel for fiscal year 2011 and the five-year forecast period are shown in *Appendix III, Detail of Operating and Maintenance Expenses.*

Based on the Revised Current Forecast, the Authority's estimated cost of fuel per barrel excluding finance charges, for fiscal year 2012 is $118.08 and is forecasted to be $111.00, $105.07, $105.81, and $102.55 in fiscal years 2013 through 2016, respectively. The composite average fuel cost per barrel from fiscal year 2012 onward includes natural gas; this is presented by equating gas consumption in MMBTU—a measure of its heating value—to equivalent barrels of distillate fuel oil based on its nominal heating value in MMBTU. 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 incidental charges. The composite fuel cost is based specifically on the mix the Authority has forecasted to be utilized in its generating units. The forecasted dispatch and fuel use are shown in *Appendix IV, Annual Generation, Fuel Consumption, and Fuel Costs for Thermal Stations.*

In projecting the price per barrel of all fuel oil the Authority adds $0.40 for transportation and handling, plus the interest on the Authority's fuel credit line, which escalates from $0.22 to $0.49 over the five year period, and a Commonwealth tax of $3.36 is also added to the cost of distillate fuel oil.

Natural gas firing at Costa Sur Units 5 & 6 is projected to begin late in fiscal year 2012 following completion of the expansion of the regasification capacity at EcoEléctrica, consequently the Authority's fuel mix for fiscal year 2012 will include less than 2% of its generation from natural gas. The Authority's fuel mix is forecasted to increase to more than 17% gas the following year and remain a significant source through the forecast period. To establish the future cost of LNG for its forecasts, exclusive of EcoEléctrica, the Authority has referenced available international LNG pricing and applied an adjustment factor for transportation and regasification costs in Puerto Rico. The long term supply of natural gas may involve alternative pricing structures, however these had not yet been established at the end of fiscal year 2011.

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

The Authority's total fuel oil storage capacity is 4.3 million barrels, including rented storage. As discussed in the *Fuels* section of *System's Operation,* in October 2009 there was an explosion and fire at a fuel storage facility that supplied the Authority's San Juan and Palo Seco power plants. During fiscal year 2011 the damaged fuel storage facility was acquired by a new owner that has begun remediation work and restoration of fuel storage capacity; the intent is to make a portion of this capacity available to the Authority. Including rented fuel storage tanks the Authority has continued to maintain 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.

COGENERATOR FUELS

Natural Gas Fired

In March 2000 the Authority entered into a 22-year contract with EcoEléctrica, L.P. to purchase all its generation up to 507 MW of power produced by the first natural gas fired facility on the island. In fiscal year 2011, EcoEléctrica, L.P. represented 8.6% of the System's capacity and provided 16.6% of the Authority's dispatchable energy. For fiscal year 2012 the energy provided to the Authority's from natural gas is forecast to be 16.0% of the system total.

As discussed above, the Authority's long-term fuel strategy has been to increase the use of natural gas in new and selected existing units, with the dual fuel conversion at Costa Sur Units 5 & 6 being the first units. These units will utilize the expansion of LNG regasification capacity at the EcoEléctrica facility. When the Authority's contributions are included, the total generation from natural gas is projected to be 17.1% in fiscal year 2012 and 27.2% the following year.

Coal Fired

The AES-PR plant began commercial operation in November 2002. The 454 MW plant uses fluidized bed boilers, which are considered a clean coal-burning technology. The Authority has entered into a 25-year PPOA 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 16.2% of the Authority's dispatchable energy during fiscal year 2011. It is anticipated that the plant will provide 16.1% of the system's total generation in fiscal year 2012. 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 energy sales and revenues. The methodology and results of the Current Forecast are discussed in the *Current Forecast* section above. In summary, the Authority typically chooses the least expansive or most pessimistic projection over the intermediate five-year period for its financial forecast to account for the uncertainty inherent in economic forecasting. The Authority generally uses projections from three economic consultants. These consultants forecast three key macroeconomic indicators—Gross Domestic Product, Gross National Product and Personal Disposable Income—which are used with other variables to project the intermediate-term electric sales and revenues.

SHORT-TO-INTERMEDIATE TERM ENERGY SALES FORECAST

As discussed in the *Current Forecast* section, in three out of the last four years there had been a contraction of energy sales. The actual total energy sales in fiscal year 2011 decreased 3.8% from the previous year with all sectors decreasing: Residential by 5.0%, Commercial by 2.4%, Industrial by 5.5% and Other by 3.0%.The projection from last year's Current Forecast was a 0.1% decrease in total energy sales for fiscal year 2011.

As shown in the table below, total sales for fiscal year 2012 are projected to decrease by 3.0%, based on the Revised Current Forecast. The decline in total energy sales is projected to continue in fiscal year 2013 with a decrease of 1.1%. The trend is forecasted to reverse starting in fiscal year 2014 with the increase in annual energy sales for fiscal years 2014 through 2016 being 0.3%, 1.1%, and 1.5%, respectively.

Last year's Current Forecast projected that energy sales would increase at a CAGR of 0.3% over the five-year period ending in fiscal year 2015. Based on the Revised Current Forecast, this year's projections for fiscal years 2012 through 2016 are consistent with the previous, with an annual decrease of 0.3% 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 2016 will be 0.8%.

The projected energy sales through fiscal year 2016, taken from the Authority's Revised 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 2010 and 2011. It also shows the projected kilowatt-hour sales and percent change from the prior year by major client classifications for fiscal years 2011 and 2012 taken from the Authority's Revised Current Forecast.

SHORT-TERM ENERGY SALES FORECAST
(GWh)

	2010 Actual	2011 Actual	2012 Forecast[1]
Residential Sales	7,056.6	6,707.5	6,481.4
Annual Increase (Decrease)	*10.8%*	*(4.9%)*	*(3.4%)*
Commercial Sales	8,758.9	8,551.4	8,373.9
Annual Increase (Decrease)	*3.1%*	*(2.4%)*	*(2.1%)*
Industrial Sales	3,047.1	2,881.2	2,722.6
Annual Increase (Decrease)	*(7.3%)*	*(5.4%)*	*(5.5%)*
Other Sales[2]	372.3	361.3	362.3
Annual Increase (Decrease)	*3.0%*	*(3.0%)*	*0.3%*
Total Sales	19,234.9	18,501.4	17,940.2
Annual Increase (Decrease)	3.9%	(3.8%)	(3.0%)

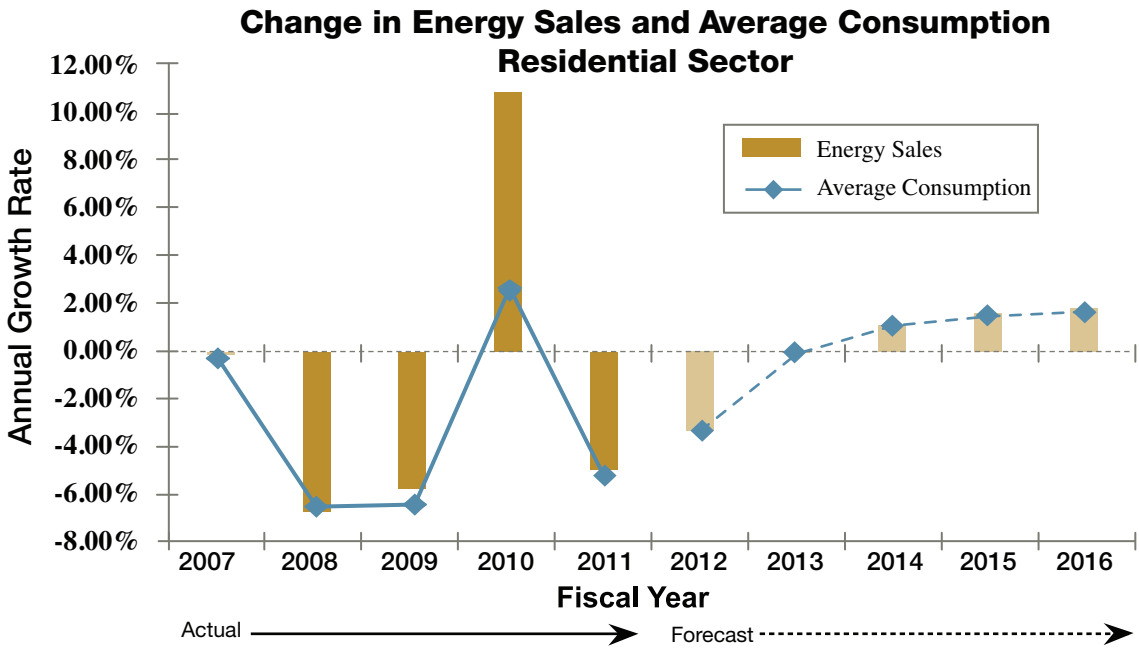
1. Revised Current Forecast.
2. Other Sales are comprised of Agricultural, Other Public Authorities, and Public Lighting.

The energy sales statistics for the U.S. cited in the following discussions are taken from EIA reports: *Annual Energy Outlook 2011 with Projections to 2035* dated April 2011, *US Electric Power Monthly – December 2011 and Short-term Energy Outlook – January 2012.* The US 2010 calendar year energy sales are preliminary and 2011 are estimated.

RESIDENTIAL KWH SALES

Following a fiscal year in which the residential sector had an annual increase of 10.8% the decrease in energy sales for fiscal year 2011 was 5.0%. The Authority partly attributes the growth in sales in fiscal year 2010 to the warmer than usual weather and the modest decrease in the average cost of electricity for this sector. In the Authority's Revised Current Forecast, residential energy sales for fiscal year 2012 are estimated to decrease by 3.4%.

Actual residential energy sales for the five-year period ended June 30, 2011 decreased at a CAGR of 1.5%. The average number of customers during this five-year period increased at a CAGR of 0.4% and the average consumption decreased at a CAGR of 1.9%.



The Revised Current Forecast projects that the residential sector consumption will increase at a CAGR of 0.2% through fiscal year 2016. During this five-year forecast period the average number of customers is projected to increase at a CAGR of 0.1%, with the average client consumption decreasing at a CAGR of 0.2%.

The average number of residential clients the Authority served during fiscal year 2011 was 1,341,291—an increase of 0.4% from the previous year.

In fiscal year 2011 the average annual electric consumption per residential client was 5,001 kWh, which was 5.3% less than the previous fiscal year. There has been a reduction in the average annual electric consumption per residential client in seven out of the last eight years with fiscal year 2010 being the exception. In fiscal year 2012 the average residential energy consumption is forecast to decrease by 3.3%, with marginal growth continuing throughout the five-year period.

EIA data for recent performance of the U.S. electric sales are preliminary. These data show that U.S. residential energy sales increased 6.8% in calendar year 2010 and are estimated to increase by 0.6% in calendar year 2011. The preliminary five-year CAGR in U.S. residential energy sales for calendar years 2005 through 2010 is 1.4%. The projected five-year compound growth rate in U.S. residential energy sales for calendar years 2011 through 2016 is negligible.

According to EIA statistics, the average electric consumption of the Authority's residential clients is approximately 37% of the average electric consumption of residential clients of the U.S. South Atlantic Census Division.

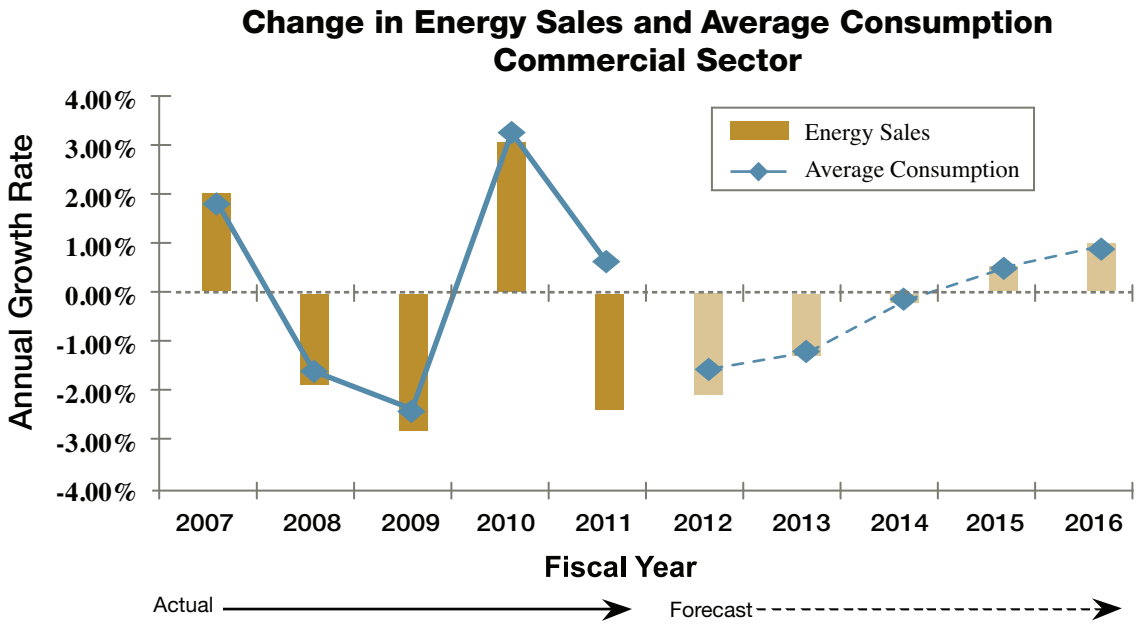
COMMERCIAL KWH SALES

Commercial energy sales for year fiscal year 2011 decreased 2.4% from the previous fiscal year. This is the third decline over the last four years in this sector. In fiscal years 2010 commercial energy sales had increased 3.1% from those of the previous fiscal year. The Revised Current Forecast projects that commercial energy sales will decrease by 2.1% in fiscal year 2012.

The five-year CAGR of commercial sales from 2006 through 2011 was -0.4%. The Revised Current Forecast projects a future five-year CAGR from fiscal years 2011 through 2016 of 0.4%, which is less than last year's Current Forecast which had projected a CAGR of 0.8% in commercial energy sales over the five-year period ending in fiscal year 2015.

The average number of commercial clients during fiscal year 2011 was 129,537, an increase of 0.3% from the previous fiscal year reversing three years of declines. The size of the commercial client base in fiscal year 2011 was essentially the same as it had been in fiscal year 2005, even after the addition of 612 clients in fiscal year 2009 by reclassification from the industrial class. In fiscal year 2012 the average number of commercial clients is projected to decrease by 0.5% and remain basically unchanged for the balance of the five year forecast.

The average annual consumption per commercial client during fiscal year 2011 was 66,015 kWh for a



decrease of 2.6% from the previous year. The Authority's actual five-year CAGR in consumption per commercial client through the end of fiscal year 2011 was negative 0.3%. For fiscal year 2012 the average energy consumption per commercial client is projected to decrease by 1.5%. The Revised Current Forecast projects a CAGR of negative 0.3% in electric consumption per commercial client over the next five fiscal years.

Based on preliminary EIA data, U.S. commercial energy sales increased by 2.0% in calendar year 2010 and are estimated to increase by 1.6% in calendar year 2011. The preliminary five-year CAGR in U.S. commercial energy sales for calendar years 2005 through 2010 is 1.1%. The projected five-year CAGR in U.S. commercial energy sales for calendar years 2009 through 2014 is 1.2%.

According to EIA statistics, the average energy consumption of the Authority's commercial clients is approximately 77% of commercial clients of the South Atlantic Census Division of the U.S.

INDUSTRIAL KWH SALES

Industrial energy sales for the fiscal year 2011 decreased 5.5% compared to the previous year during which industrial energy sales had decreased 7.3%. This year marked the fifth consecutive year that Industrial energy sales have diminished. Actual industrial energy sales for the five-year period ending in fiscal year 2011 decreased at a CAGR of 7.4%.

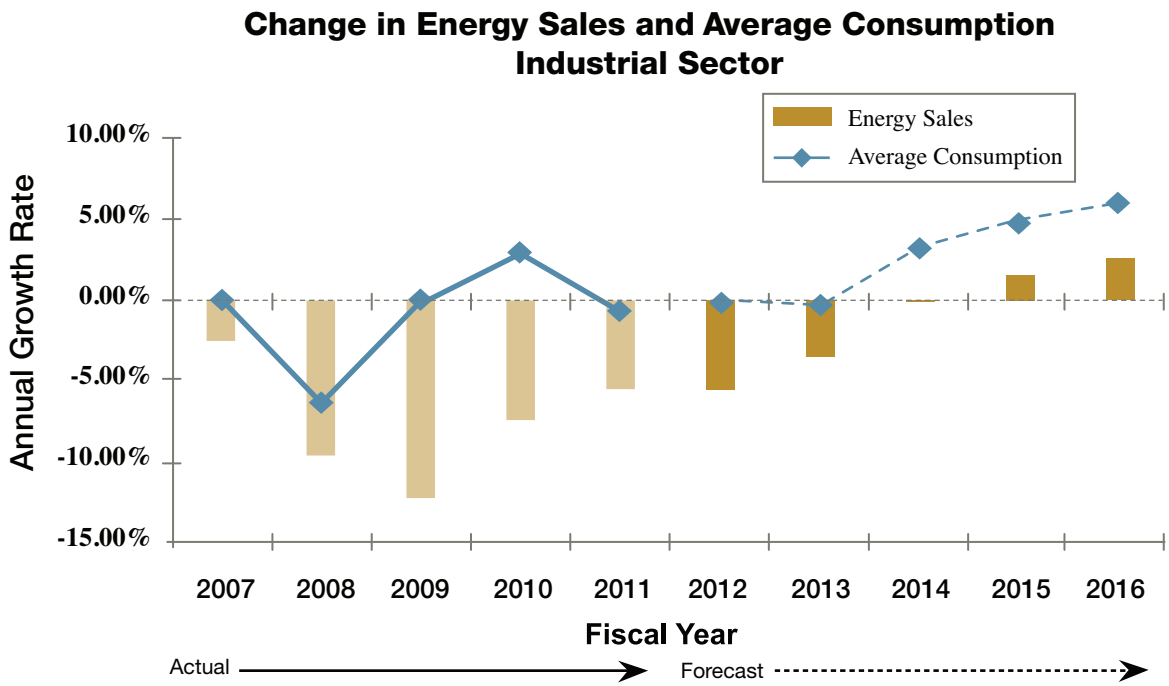
The Revised Current Forecast projects that in fiscal year 2012 industrial energy sales will continue to decrease by 5.5%, followed by diminishing annual declines leading to stabilization in fiscal year 2014 and 1.6% and 2.6% growth in fiscal years 2015 and 2016, respectively. The industrial class energy sales are forecasted to expand at a CAGR of 1.0% for the five-year period through fiscal year 2016.

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%.

The average number of industrial clients served by the Authority at the end of fiscal year 2011 was 770, which was 4.7% less than the previous fiscal year. The average annual consumption of those clients was 3,742 MWh. The Revised Current Forecast projects the number of industrial clients to decrease by approximately 25 clients per year over the next five years.

The average consumption per Industrial client is omitted from the graph for fiscal year 2009 because of the reclassification. The CAGR for the future five-year period ending in 2016 in energy use per client is projected at to increase by 2.7%.

Preliminary EIA data show total industrial U.S. energy sales increased 6.3% in calendar year 2010 and is estimated to increase by 2.9% in calendar year 2011. The preliminary five-year CAGR in U.S. industrial energy sales for calendar years 2005 through 2010 is negative 1.7%. The projected CAGR in U.S. industrial energy sales for calendar years 2011 through 2016 is 1.3%.



According to EIA statistics, the average energy consumption of the Authority's industrial clients is approximately 124% more than those of the South Atlantic Census Division of the U.S.

OTHER CLASSES KWH SALES

The sum of the energy sales in fiscal year 2011 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 2011 the group's energy sales were 3.0% less than that of the previous year. In fiscal year 2010 the Other sector posted an increase in energy sales of 3.0%. The Authority's Revised Current Forecast projects virtually no change in energy sales to this group throughout the forecast period. The number of clients in this group is also projected to remain unchanged during the forecast period.

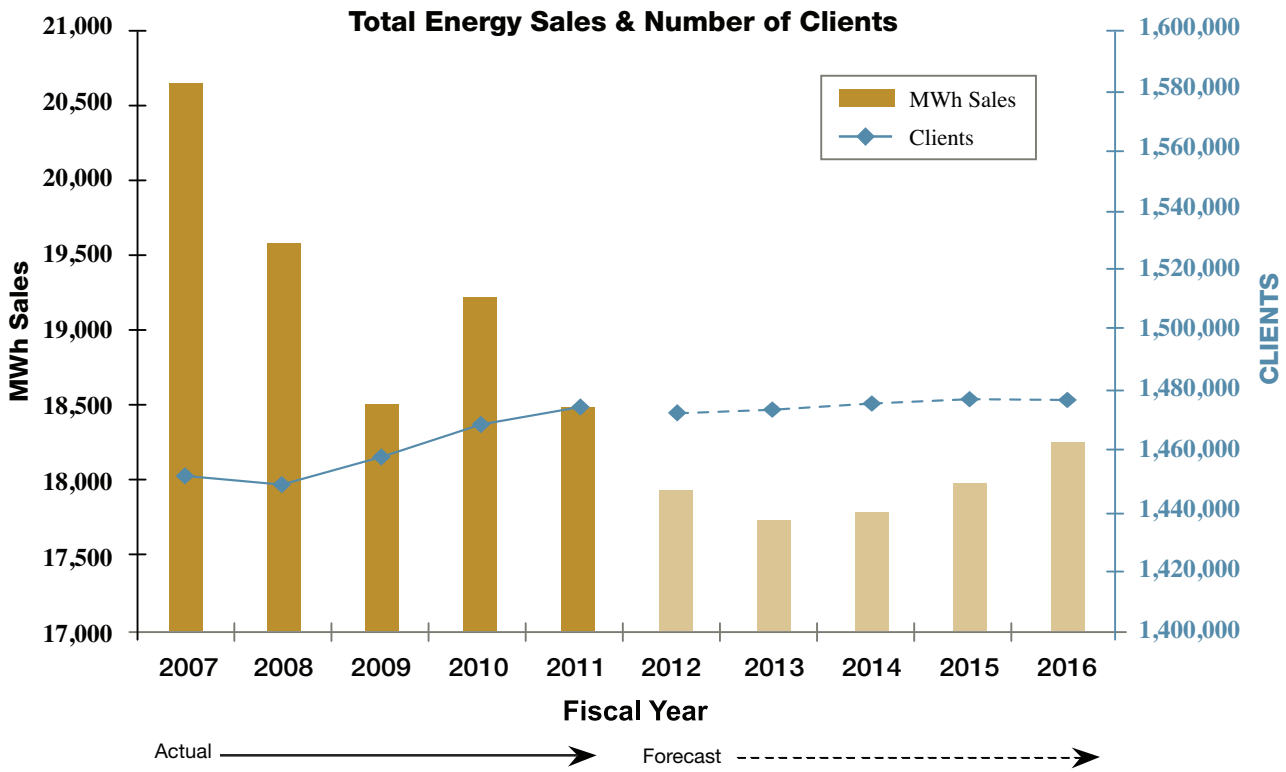
TOTAL KWH SALES

Total energy sales in fiscal year 2011 were 18,501.4 GWh, a decrease of 3.8% with those of the previous fiscal year. The decline in total energy sales is the third in four years. Actual total energy sales for the five-year period ended June 30, 2011 decreased at a CAGR of 2.1%. In the Revised Current Forecast total energy sales are expected to decrease by 3.0% for fiscal year 2012 and to decrease at a CAGR of 0.3% per year over the five-year period ending in fiscal year 2016; this contrasts with an increase of 0.3% in total energy sales projected in last year's forecast for the five-year period ending in fiscal year 2015.

The average number of clients that the Authority served during fiscal year 2011 increased 0.3% from the previous fiscal year to 1,475,126. Over the five-year period ending in 2011 the CAGR in the number of clients was 0.4%. The total number of clients is projected to remain essentially unchanged through the next five years of the forecast period ending in 2016.

The average electric consumption of the Authority's clients in fiscal year 2011 was 12,542 kWh, a decrease of 4.2% from the previous year. Over the past five-year period the CAGR was negative 2.5%. The Revised Current Forecast projects the average consumption of the Authority's clients will decrease in fiscal year 2012 by 2.9%, and the future five-year CAGR is projected to decrease by 0.3% annually through fiscal year 2016.

The preliminary data for total U.S. energy sales show an increase of 4.3% in calendar year 2010. For calendar year 2011 total energy sales in the U.S. are estimated to increase by 0.5%. The CAGR for the U.S. preliminary total energy sales during the five-year period between calendar years 2005 and 2010 is 0.5% and is projected to be 0.8% for the five-year period ending in 2016.



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 2011, 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 2011 the core four rates accounted for 86.7% of the Authority's kilowatt-hour sales and 88.0% 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 classifications there is dominant rate schedule. For example, although four rate schedules apply to the Residential classification, the GRS rate schedule served 88.4% of the Residential clients' kilowatt-hour sales and accounted for 90.9% of the Residential class revenue in fiscal year 2011. Within the Commercial classification seven rate schedules applied in fiscal year 2011, however, the GSP rate schedule, which served 7.9% of the Commercial clients, accounted for 53.0% of the Commercial class revenue. The GSS rate schedule generated the second most revenue in the Commercial classification; it served 91.7% of the Commercial clients and accounted for 29.5% of the Commercial class revenue. While fourteen rate schedules applied to the Industrial classification in fiscal year 2011, the GST rate schedule, which served 31.9% of the Industrial clients, accounted for 49.0% 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	32.0%	33.6%	24.23
General Service Secondary Voltage	12.4%	14.1%	27.10 – 26.98
General Service Primary Voltage	25.4%	26.4%	24.76 - 25.12
General Service Transmission Voltage	16.9%	14.9%	21.07 – 20.92

* Commercial – Industrial Classes

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. Six of the rate schedules are common to both the commercial and the industrial classifications.

As shown on the Rates Table, the average cost per kWh for all power sold by the Authority was 23.82 cents during fiscal year 2011. The lowest average cost among the four popular rate schedules was 20.92 cents/kWh for GST – Industrial, with the highest average cost being 27.10 cents/kWh for GSS – Commercial.

The Authority's ten largest industrial clients (25.8 % of the classification's consumption) paid an average of 19.10 cents/kWh during fiscal year 2011. This was 7.7% less than the industrial class average.

The Rates Table below shows all the rate schedules in use during fiscal year 2011 by the Authority's clients, with the average number of clients, total annual sales,total revenue and average pricing for each rate schedule.

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 residential class was the only one not paying a separate demand charge. The base 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 fuel adjustment clause was revised by the Authority 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.

The Authority invoiced $3,319.1 million through the adjustment charge in fiscal year 2011: $2,578.9 million for fuel and $740.3 million for purchased power. The adjustment charge constituted 75.3 % of the Authority's $4,406.2 million electric revenue.

RATES TABLE

Rate Schedule	Average Number of Clients	Total MWh	Total Revenue ($000)[1]	Average Cost Cents/kWh[2]
Residential Class[2, 3]				
103-104 (RH-3)	13,275	42,253	8,722	20.64
105-107 (RH-3) *Rev.*	35,079	200,166	16,606	8.30
109,110 (LRS)	151,694	536,229	117,747	21.96
111,112 (GRS)	1,141,242	5,928,838	1,436,371	24.23
Total Residential Class	*1,341,291*	*6,707,486*	*1,579,446*	*23.55*
Commercial Class[2]				
060 Telephone Booth	59	11	3	28.39
070-080 Cable TV	7	15,788	4,182	26.49
082 Security Cameras	140	87	31	35.62
211 (GSS)	118,723	2,289,929	620,660	27.10
212 (GSP)	10,267	4,511,587	1,117,101	24.76
213 (GST)	340	1,726,272	363,672	21.07
862	1	7,761	1,800	23.19
Total Commercial Class	*129,537*	*8,551,435*	*2,107,448*	*24.64*
Industrial Class[2]				
311 (GSS)	145	6,136	1,656	26.98
312 (GSP)	334	187,342	47,065	25.12
313 (GST)	246	1,396,651	292,145	20.92
333 (LIS)	2	146,183	28,427	19.45
343 (PPBB)	2	538	1,895	352.43
363 (TOU-T)	13	465,052	93,848	20.18
393 (SBS-T-TOU)	1	21,484	5,163	24.03
603 (SR-GST)	7	79,625	14,802	18.59
613 (SR-GST)	14	283,490	56,195	19.82
633 (SR-TOU-T)	1	17,657	3,652	20.68
643 (SR-TOU-T)	2	90,205	17,589	19.50
653 (SRTOU-T)	1	88,190	17,047	19.33
663 (SR-LIS)	1	77,765	11,844	16.28
963(TOU-T)	2	25,843	4,719	18.26
Total Industrial Class	*770*	*2,881,159*	*596,047*	*20.69*
Total Industrial Class	*898*	*3,288,597*	*601,985*	*18.31*
Other Classifications[2]				
Public Lighting				
2-41 (Non Meter P/L)	162	245,033	96,629	39.44
72 (PLG Bus Shelter)	3	548	134	24.40
73 (PLG Police)	5	34	7	20.98
414 (LP-13)	10	3,563	983	27.60
421 (PLG)	93	1,788	473	26.42
422 (PLG)	80	1,406	327	23.26
423 (PLG)	715	4,238	1,032	24.36
424 (PLG)	1,158	21,192	4,952	23.37
050-056 (Dusk to Dawn)3	0	3,172	713	22.47
Total Public Lighting	*2,225*	*280,973*	*105,250*	*37.46*
Agricultural				
711 (GAS)	1,300	29,216	7,428	25.42
Total Agricultural	*1,300*	*29,216*	*7,428*	*25.42*
Public Authorities				
513 (GST-Public Authority)	3	51,141	10,538	20.61
Total Public Authorities	*3*	*51,141*	*10,538*	*20.61*
Total[4] Other Classifications	*3,527*	*361,330*	*123,215*	*34.10*
Total	*1,475,126*	*18,501,409*	*4,406,155*	*23.82*

[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.

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 37.46 cents/kWh while the Industrial class paid the lowest average cost of 20.69 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, 2011. 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.

2011 AVERAGE PRICE COMPARISON
(Cents/kWh)

	Authority	Hawaii	U.S.
Residential	23.55	30.42	11.69
Commercial	24.64	28.13	10.31
Industrial	20.69	24.08	6.85
All Classes	23.82	27.33	9.82

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 and credits benefited 476,791 clients in fiscal year 2011, which is approximately 32% of its client base. The total costs to the Authority for the benefits credited to these clients during fiscal year 2011 was $71.8 million. In fiscal year 2010, approximately 33% of the Authority's clients benefited from $78.3 million in subsidies and credits. Funds for these subsidies were drawn from the Set Aside moneys discussed in the *Contributions in Lieu of Taxes and Other* 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 2011, there were 296,303 clients or 22% of the total residential classification who qualified for subsidization. The purchased power component of the adjustment charge is not subsidized.

The residential fuel subsidy was $26.8 million during fiscal year 2011; for the previous fiscal year this subsidy totaled $29.6 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 fiscal year 1992, the residential fuel subsidy was paid by the Commonwealth and was recorded as a receivable by the Authority. By the end of fiscal year 1991, the Commonwealth owed the Authority $94.9 million for 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 2011 the balance owed by the Commonwealth was $12.7 million; the Commonwealth made a payment of $6.3 million during fiscal year 2011.

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 is capped at $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 2011 ranged from a low of $ 77.77 per barrel in July 2010 to a high of $118.00 per barrel in June 2011. The average fuel cost for the fiscal year 2011 was $ 95.91 per barrel, which is up over 25% from the previous year.

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 four rates—GRS, LRS (Lifeline), and RH-3 (Public Housing) and a revised RH-3 rate. In fiscal year 2011, 85.1% 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 2011 the Authority served an average of 200,048 residential clients under the rates of LRS ,RH-3, and RH-3 Revised, which is discussed in *Selected Rates.* Approximately 164,970 or about 12% of the clients received the subsidy; in terms of revenue, the $15.5 million subsidy represents about 10% of the total residential subsidy.

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 2011, an average of 198 establishments benefited from the $7.4 million in hotel subsidies.

CHARITABLE ORGANIZATIONS SUBSIDY

This subsidy applies to charitable organizations, such as churches, which provide services to the community at no charge. The subsidy enables any qualifying charitable organization to use the GRS rate (average cost of 24.23 cents/kWh during fiscal year 2011) in place of the other applicable commercial rates (27.10 cents/kWh for GSS or 24.76 for GSP). Applying the GRS rate in place of the GSS rate reduced the client cost by 10.6% in fiscal year 2011; the GRS rate in place of the GSP rate saved only 2.1%.

The Authority subsidized $3.6 million to serve an average of 4,280 charitable organizations in fiscal year 2011.

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 4,541 clients and amounted to $4.1 million in fiscal year 2011.

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-Commercial rate. The average price differential between the GSS-Commercial and GAS rates was 1.68 cents/kWh based on their average costs in fiscal year 2011.

This subsidy served an average of 1,300 clients and amounted to $0.6 million in fiscal year 2011.

IRRIGATION SERVICE 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 2011 the Authority incurred costs of $4.5 million for these services.

OTHER SUBSIDIES AND 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 2011 an average of 12 rural water companies took advantage of this subsidy and received a benefit of approximately $4,900.

Since July 2, 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. In fiscal year 2011 more than 4,100 residential clients took advantage of this credit and saved $159,791.

The Authority provides a 10% credit for power, up to a maximum of $40 per month, to small commercial clients with less than seven employees on the weekly payroll. This credit applies for up to three years. During fiscal year 2011 the credit provided was approximately $2,500 to fourteen 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 2011, the Authority provided its manufacturing industry users a credit of $7.9 million to an average of 26 clients; which was a decrease from the previous fiscal year's credit of $9.8 million. 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 residential public housing, 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.

PUBLIC HOUSING RESIDENTIAL RATE

As shown in the Rates Table above, approximately 3.3% of the Authority's residential clients are served by the RH-3 public housing rate. In August 2009 the Commonwealth enacted legislation, under Act No. 69, entitled Special Law for Pricing Justice of Utilities for Public Residents. The Special Law provides simplified low cost water and electric utility rates for qualifying low income residents of public housing. The new electric rates went into effect in February 2010, under the scope of RH-3 Revised. The rate structure establishes flat monthly charges based on the number of rooms: $30 for one room, $40 for two or three rooms, and $50 for four or five rooms. The rate applies for usage up to 425 kWh per month. For a client to transition from RH-3 to the RH-3 Revised tariffs he must agree to a payment plan if he has overdue invoices. By the end of fiscal year 2011, almost 73% of the total RH-3 clients had opted for the RH-3 Revised rate. The clients served under the RH-3 Revised rate consume 82.6% of the total RH-3 power and contribute only 65.6% of the total RH-3 revenue.

While the legislation provides rate relief to these clients, the Authority views this as an opportunity to increase revenue collections by adding some residential units that did not have currently active accounts. In addition the law also increases the Authority's sanctions to collect past due utility bills from a client base within which a significant portion have had accounts that were historically in arrears.

SPECIAL RATES

In order to promote an increase in industrial development in Puerto Rico, the Authority instituted five new special rates. These special rates offered a discount for new industries and expansion of existing industrials on or after February 2002. New industrial clients received a discount of approximately 11% on their total electric bill. Also, existing industrial clients that expanded their operations received a discount of approximately 11% on the demand, energy, and adjustment charges associated with its expansion. 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. During fiscal year 2011 these rates benefited qualifying industrial clients with savings of $7.9 million; the saving was $9.8 million for fiscal year 2010. 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)

Only three of these rates —SR-GST, SR-TOU-T, and SR-LIS— were used during fiscal year 2011. The SR-GST rate was used by 21 clients with a combined average cost of 19.55 cents/kWh. The SR-TOU-T Rate served three clients at a combined average cost of 19.69 cents/kWh; the SR-LIS Rate, with an average cost of 16.28 cents/kWh, was used by only one client.

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. In view of the declining industrial client base, the Authority has relaxed the 80% load factor to 50% for LIS and SR-LIS, however the 50% load factor is then the minimum basis for monthly billing. The Authority served two industrial client under the LIS rate during fiscal year 2011, an increase from only one client during fiscal years 2010. The average cost per kWh for this rate was 19.45 cents/kWh in fiscal year 2011; its average cost for the previous fiscal year was 15.13 cents/kWh.

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 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 has several TOU rates; currently these rates are only offered to the Authority's commercial and industrial clients.

In May 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. At the end of fiscal year 2011, a total of 20 clients were served under these rates, resulting in $142.0 million in revenues, which is approximately 24% of the total industrial classification's revenue. Thirteen clients were served using the TOU-T (time of use at transmission voltage) rate at an average cost of 20.18 cents/kWh. The SBS-T-TOU (time of use at standby service at transmission voltage) rate served only one client at an average cost of 24.03 cents/kWh in fiscal year 2011.

Four 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 four clients was 19.53 cents/kWh for fiscal year 2011.

The last TOU rate utilized in fiscal year 2011 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 2011 this TOU-T rate served two clients with an average cost of 18.26 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 attracted few clients and the last one changed to a conventional rate two years ago.

POWER PRODUCERS AT BUS BAR RATE

In March 2000, the Authority's Governing Board, under Resolution Number 2812 approved the Power Producers at Bus Bar (PPBB) rate. This rate, which became effective in June 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 $1.9 million in revenues from the sale of 538 MWh of power to the two cogenerators in fiscal year 2011.

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.

During fiscal year 2011 the only standby rate in use was for one industrial client utilizing the SBS-T-TOU rate, which was discussed above in *Time-of-Use Rates.* The average cost of the SBS rate serving the lone industrial client was 24.03 cents/kWh. The Authority derived $5.2 million in revenue from the sale of 21,484 MWh from this rate.

SECURITY CAMERAS RATE

As part of an increased public safety program throughout the Commonwealth, 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 anywhere on the island. Before installation of these security devices, the client is required to provide all equipment specifications to the Authority's Director of Transmission and Distribution. The electric consumption for each installed security camera may not exceed 200 kWh per month.

During fiscal year 2011 an average of 140 clients used this rate. The average monthly consumption was 52 kWh per client, the same as the previous fiscal year, and the average cost was 35.62 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 2011 the Authority performed a cost of service study based on fiscal year 2009 data. This study employed methodologies that are commonly accepted in the electric utility industry. The study results included the allocation of costs and revenues shown below as well as an analysis based on rate base and its rate of return

The revenues, expenses and recovered cost percentage from the most recent cost of service study for the major classes of service are summarized below:

2011 COST OF SERVICE RESULTS BASED ON 2009 DATA
($ millions)

Rate Schedule/Class	Collected Revenues	Cost to Serve	Recovered Cost Percentage
Residential	1,388.4	1,608.0	86.3
Commercial	1,915.2	1784.1	107.3
Industrial	608.1	585.5	103.9
Other Classes	115.1	202.1	57.0

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 2011 was 1.47. The debt service coverage for fiscal year 2012 is forecasted to be 223% based on the Authority's Annual Budget discussed in the *Financial* section.

FINANCIAL

The financial data used in the Annual Report are based on information provided by the Authority and Schedules II through VI of the Audited Financial Statements prepared by the Authority's Auditors for fiscal year 2011. These Schedules present certain information in accordance with the 1974 Agreement, including a reconciliation of Net Revenues under generally accepted accounting principles with the 1974 Agreement. The financial data in the Annual Report are based on accrual basis accounting.

When this report was initially issued on February 23, 2012 the Consulting Engineers noted that the Authority was updating its budgets, forecasts and the Capital Improvement Program for fiscal years 2013 and after. This amended report incorporates the budgets and forecasts that were subsequently developed and are consistent with those in the Official Statement prepared for the Power Revenue Bond Series 2012A and 2012B. For the most part the revisions in this amended report are limited to the *Financial* section and the *Appendices.*

The latest budgets include reductions in operating and maintenance expenses for fiscal years 2013 through 2016, increased revenues from theft recovery, the Rate Stabilization costs in fiscal year 2012, reduction in forecasted earned interest, changes in the forecasted Contributions in Lieu of Taxes and Other, revisions in internal funding of the Capital Improvement Program and revised debt service requirements. The allocation of funds within the Capital Improvement Program was revised for fiscal year 2013 and after, however, the total annual amounts were unchanged.

As discussed in the *Current Forecast* section, the budget for fiscal year 2012 and projections through fiscal year 2016 were revised during the first half of the fiscal year. The resulting Revised Current Forecast has continued to be the basis for the latest budgets and forecasts for energy sales, peak demand, fuel prices, fuel mix and unit dispatch.

ANNUAL BUDGET

The Annual Budget, prepared in conformance with Section 504 of the 1974 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.

The Proposed Annual Budget of Current Expenses and Capital Expenditures—Fiscal Year 2011-2012 was approved in June 2011 by the Consulting Engineers prior to the Governing Board's adoption later that month.

As discussed in the *Current Forecast* section, the budget for fiscal year 2012 and projections through fiscal year 2016 were revised during the first half of the fiscal year. The budget dated January 19, 2012 was reviewed by the Consulting Engineers and was the basis of the forecast data in the initial issue of this report. The budget of Current Expenses for fiscal year 2012 was not revised subsequently, except for adjusting functional group operations budgets to keep the maintenance budgets at the same level as fiscal year 2011 expenditures. The budget dated March 16, 2012 was reviewed by the Consulting Engineers and is the basis for this amended report, with adjustments for debt service schedules and requirements as shown in the Official Statement prepared for Series 2012A and 2012B.

REVENUES

Total revenues booked for fiscal year 2011 were $4,411,213,212, or 2.5% less than the $4,522,113,000 that was budgeted, principally because energy sales were 3.7% below budget. Total revenues for fiscal year 2012 are forecasted to be $4,925,742,000; compared to the actual revenues in fiscal year 2011 this is a projected increase of 11.7%, resulting from the forecasted increase in fuel costs outweighing the projected decline in energy sales. Beginning in fiscal year 2010 the Authority has adjusted the forecasted total revenues from electricity to reflect recovery of sales lost to theft. The Authority's forecasted revenues for fiscal year 2012 include $25,000,000 for billings of power lost to theft as a result of the significant initiative to recover these losses. The additional theft recovery revenue is forecasted to be $30 million per year from fiscal year 2013 through 2016. For fiscal years 2013 through 2016 total revenues are forecasted to be $4,767,006,000, $4,641,094,000, $4,679,427,000, and $4,731,243,000 respectively. *Appendix II, Income Statement,* presents the Authority's income statements (including interest income) for fiscal years 2011 through 2016.

The total revenues above reflect an increase of $5 million per year in projected theft recovery and a decline of $810,000 per year in projected Other Income, principally earned interest. In fiscal year 2012 the revenues include a reduction of $70 million for the cost of the Rate Stabilization program, which is a temporary dis-

count to non-subsidized residential clients that is projected to expire before the end of the current fiscal year.

Revenues from electric sales are shown on *Appendix I, Intermediate-term Financial Planning Forecast* which breaks down the revenues by sector and the three components that the revenue is based on—the base revenue, the fuel oil charge and the purchase power adjustment charge—for the six year period 2011 through 2016.

As shown on Appendix I, base revenues from sales of electricity for fiscal year 2011, excluding fuel and purchased power included in the adjustment charge, were $1,087,026,000 and are forecasted to be $1,054,016,000 for fiscal year 2012 or a decrease of 3.0%. The base revenue projections move with the forecasted energy sales; for fiscal years 2013 through 2016 they are $1,044,186,000—a decrease of 0.9%, $1,046,622,000—an increase of 0.2%, $1,056,284,000—an increase of 0.9%, and $1,070,640,000—an increase of 1.4%, respectively.

The Authority's total revenues include the energy sales to municipalities and other subsidy amounts which are discussed in the *Contributions in Lieu of Taxes and Other* section below. In fiscal year 2011 these contributions in lieu of taxes (CILT) and Other subsidies amounted to $197,006,365. The CILT and Other costs are forecasted to be $265,067,000, $240,295,000, $228,525,000, $223,752,000, and $220,237,000, respectively, in fiscal years 2012 through 2016.

EXPENSES

The Authority's budget for Current Expenses for fiscal year 2011 and the amounts actually expended, as well as those budgeted for fiscal year 2012, are shown below.

Expenses incurred during fiscal 2011 were more than the expenses budgeted by 0.5% or $19.3 million. Extracting fuel and purchased power the variance was 5.9% more than that budgeted.

In the revised budget of January 2012 the Authority adopted wide spread reductions in the projected operating budgets. The Authority subsequently incorporated further reductions for the fiscal years 2013 and later in the revised budget of March 2012. In the latest revised budget the current expenses less fuel and purchased power are projected to decrease by 4.3% in fiscal year 2012 as compared to actual expenses in fiscal year 2011. The forecast for the subsequent fiscal years 2013 through 2016 show annual reductions in current expenses less fuel and purchased power of 4%, 3%, 2% and 1%, respectively.

OPERATING AND MAINTENANCE EXPENSES

In fiscal year 2011, total Operating and Maintenance (O&M) expenses were $3,705,192,000 and for fiscal years 2012 through 2016 are forecasted to be $4,195,003,000, $3,966,771,000, $3,832,526,000, $3,844,768,000 and $3,871,801,000. *Appendix III, Detail of Operating and Maintenance Expenses,* shows O&M expenses by category for fiscal years 2011 through 2016.

The cost of fuel oil is the largest component of O&M expenses. During fiscal year 2011 approximately 69% of the System's energy was generated by the Authority's oil-fired plants, with a total fuel cost of $2,291.4 million; this constituted 61.8% of the total O&M expenses for the year. The total cost of fuel for fiscal year 2012 is forecasted to be 22.3% more than the actual costs in fiscal year 2011, driven by forecasted near term increases in oil prices. The Authority's forecasts of total fuel cost through fiscal year 2016, which reflects utilization of natural gas at the Costa Sur Units 5 & 6, show a decrease in the average annual rate of 1.4%. The costs of fuel in fiscal

COMPARISON OF FY 2011 BUDGETED EXPENSES TO ACTUAL EXPENSES

(in thousands)

Current Expenses	2011 Budget	2011 Actual Expenses	2011 Variance	2012 Budget	2012 Budget vs 2011 Actuals
Fuel	$ 2,239,021	$ 2,291,386	$ 52,365	$ 2,802,337	22.3%
Purchased Power	736,171	660,872	(75,299)	672,026	1.7%
Production	59,667	67,451	7,784	60,751	-9.9%
Transmission & Distribution	144,207	176,369	32,162	168,569	-4.4%
Maintenance	223,545	220,775	(2,770)	220,775	0.0%
Client Acctg & Collection	113,931	114,837	906	112,837	-1.7%
Administrative & General	165,282	173,502	8,220	157,708	-9.1%
Interest Charges	4,098	0	(4,098)	0	
Total	**$ 3,685,922**	**$ 3,705,192**	**$ 9,270**	**$ 4,195,003**	**13.2%**
Current Expenses Minus Fuel + Purch Power	710,730	752,934	42,204	720,640	-4.3%

year 2011 and the forecasted costs during fiscal years 2012 through 2016, including the type of fuel, are discussed in the *Capacity and Energy Resource Planning* 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 2011 and forecast data through 2016.

In reference to *Appendix III, Detail of Operating and Maintenance Expenses,* the forecasted breakdown of O&M expenses by category for fiscal years 2012 through 2016 reflect aggressive cost savings measures applied to a wide range of the Authority's operations. Acting as the fiscal agent for the Authority, during fiscal year 2012 the Government Development Bank hired a consulting firm to review the Authority's operations and identify areas for cost reductions, beyond those already addressed in the Authority's recent programs. Given the scope and scale of the Authority's operations, the consultant's formal recommendations are anticipated later this fiscal year. The consultant's preliminary observations, however, identified a range of processes in which the Authority could achieve cost reductions. Amongst others, the areas included supply chain, customer service, general and administrative, and inventory control. Coupling these and other measures with reductions in the number of employees by attrition provides the bases for the Authority achieving the forecasted budgets for operations and maintenance minus fuel and purchased power.

The ratio of O&M expenses to total operating revenues in fiscal year 2011was 84%; it is forecasted to remain in the range of approximately 82% to 85% throughout the five-year forecast period.

NET REVENUES

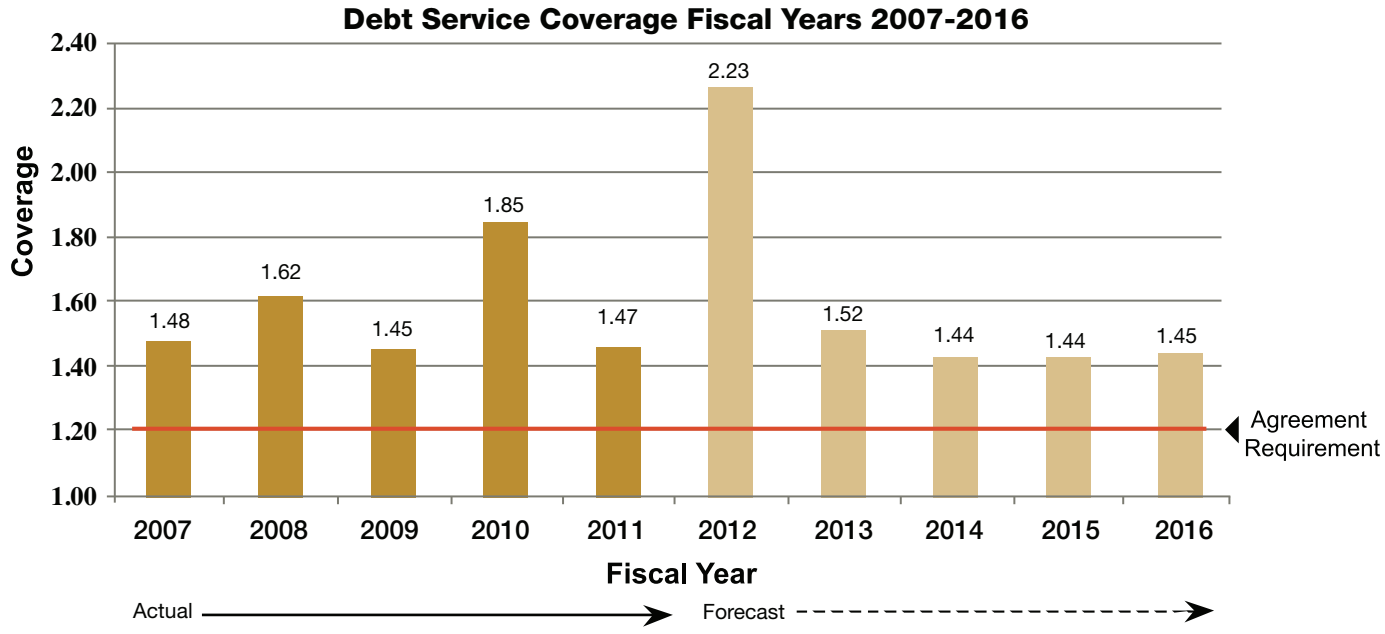
Net Revenues, as defined under the 1974 Agreement, are shown in *Appendix II, Income Statement,* as Balance to Revenue Fund. For fiscal year 2012 Net Revenues are forecast to be $730,739,000 compared to the actual amount of $706,021,000 in fiscal year 2011 an increase of 3.5%. For fiscal years 2013 through 2016 Net Revenues are forecasted to steadily improve with projected amounts of $800,235,000, $808,568,000, $834,659,000 and $859,442,000, respectively.

The projected annual increases in Net Revenues for fiscal years 2013 through 2016 are 9.5%, 1.0%, 3.2%, and 3.0%, respectively. These increases are principally attributable to reductions in the forecasted budgets for current expenses minus fuel and purchased power.

DEBT SERVICE COVERAGE

The 1974 Agreement requires that the Authority's Net Revenues as defined by the 1974 Trust Agreement must be not less than one hundred twenty per centum (120%) of the amount of the maximum aggregate Principal and Interest Requirements for any fiscal year. This ratio defines the Debt Service Coverage required under the Trust Agreement. In reference to *Appendix II, Income Statement,* the Net Revenues are shown as Balance to Revenue Fund and the aggregate Principal and Interest Requirements are shown as Total Sinking Fund Payments.

Based on the amounts shown in *Appendix II, Income Statement,* the Debt Service Coverage was 1.47 in fiscal year 2011. With the latest budget the Debt Service Coverage is projected to be 2.23, 1.52, 1.44, 1.44 and 1.45 for fiscal years 2012 through 2016, respectively. In the previous budget the corresponding values were



1.64, 1.46, 1.28, 1.24, and 1.23. 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 average Debt Service Coverage for the five fiscal years of 2007 through 2011 was 1.57, which was also consistent with the ten year period ending in 2011. With the high coverage in fiscal year 2012 the forecasted average Debt Service Coverage for the five fiscal years 2012 through 2016 is projected to maintain the same level at 1.56.

The continuation of historic Debt Service Coverage ratios is dependent on the Authority achieving the improvements in forecasted Net Revenues; these improvements are principally attributable to projected cost reductions in operation and maintenance expenses minus fuel and purchased power. As discussed above, the Authority's management is committed to reaching its budget objectives and is developing programs to lower the expenses of operations and maintenance minus the cost of fuel and purchased power; projected cost containments apply to the Authority's capital expenditures as well.

DEPRECIATION EXPENSE

Appendix IX, Depreciation Expense, shows the actual depreciation accrual for fiscal year 2011 as $382,975,969. The estimates for the ensuing five fiscal years are $398,418,000, $414,354,000, $430,929,000, $448,166,000, and $466,092,000, respectively. Depreciation Expense is excluded from statements required for Trust Agreement purposes.

The Consulting Engineers issued a draft of a comprehensive depreciation review of the Authority's Plant-in- Service as of June 30, 2009. The results which are being reviewed by the Authority show that there is no longer a deficiency between the theoretical and booked depreciation reserves and the depreciation accrual rate should be reduced. The review confirmed statistically that the production plant's average service life continues to increase. It also showed that net negative salvage (cost of removal less salvage) of retired capital equipment was no longer escalating at the rate that was shown in the previous study.

ACCOUNTS RECEIVABLE

The Authority's accounts receivable as stated on its Balance Sheet in the June 2011 Monthly Report to the Governing Board as of the end of fiscal year 2011 was $1,184.1 million or 20.9% more than the previous year's balance of $979.1 million. Of the $1,184.1 million balance $409.1 million applied to government clients, an increase of 60% from the previous year, and $673.6 million applied to general clients. The remaining balance was mostly for unbilled services.

The non-current account receivables balance for year end 2011 was $95.4 million or 13.3% less than the previous year's balance of $108.1 million.

The Auditor's Report for fiscal year 2011 shows that the allowance for uncollectible accounts increased to $214.1 million in the past fiscal year; this was an increase of $19.3 million or 9.9% over the previous year.

At the end of fiscal year 2011 the following five government agencies accounted for approximately 39% of Accounts Receivable balances owed to the Authority by Public Authorities:

Client	A/R Balance
Port Authority	$55.3 million
PRASA	$49.6 million
Urban Train Administration	$20.8 million
Public Building Authority	$18.6 million
Medical Services Administration	$13.6 million

The accounts receivables balances of Commonwealth government agencies were $54.2 million at the end of fiscal year 2011.

The Authority is continuing its effort to collect overdue accounts. The actions taken to collect from Public Authorities include working closely with the Office of Management and Budget to expedite payments. Actions taken for general clients include disconnecting electrical service, referring clients to collection and credit rating agencies, and setting up a payment schedule.

CONTRIBUTIONS TO THE COMMONWEALTH

CONTRIBUTIONS IN LIEU OF TAXES AND OTHER

Since the Authority Act was originally enacted, the Authority has been required to make certain payments to the Commonwealth government and the island's municipalities as contributions in lieu of taxes (CILT). These payments were designed to be funded with an 11% mark up on electric sales—referred to as the Set Aside—and to be paid or credited from Net Revenues, as defined by the 1974 Agreement. Over the years the Commonwealth's legislature has revised and added certain subsidies and revised certain provisions of the payments to the municipalities, however, the basic framework of these contributions has remained. In reference to the disposition of Net Revenues as shown on *Appendix II, Income Statement,* the Authority considers the total amount of CILT and Other to include its contributions to the municipalities, plus three subsidies and the amortization cost of a settlement with

the municipalities regarding disputed CILT obligations prior to 2004.

Under current law the free consumption of electricity by the municipalities constitutes the dominant portion of the total for CILT and Other. In fiscal year 2011 the total credited amount of CILT and Others was 28% of the Authority's Net Revenues, this was consistent with the five year average of 29% since fiscal year 2007 when the Authority began deferring portions of its current year obligations; the obligations in fiscal year 2011 totaled 36% of Net Revenues. As discussed below, the current law establishing the Authority's CILT obligations provides for deferral of current year payments for up to three years. These CILT and Other obligations have been paid or credited from the Authority's Net Revenues after certain defined expenditures, subject to compliance with its obligations under the 1974 Agreement. While initially the contributions in lieu of taxes were paid to the Commonwealth's Secretary of the Treasury for distribution to the municipalities, for many recent years these contributions have effectively amounted to a full credit to the municipalities for their electric power consumption.

In 1998, the Municipality of Ponce filed a complaint seeking payment from the Authority for the full amount of the contributions in lieu of taxes, plus a potential addition based on available net revenues, 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 had been reduced by such application. The Authority settled this litigation with the municipalities in 2004 by offering a monetary payment of $68 million and $57 million for electric infrastructure projects, for a total of $125 million. At the end of fiscal year 2011 the outstanding balance of the loan used for the monetary settlement was $30.0 million.

In 2004 legislation was enacted that revised the formula for computing contributions in lieu of taxes and set aside. The amended legislation requires the 11% mark up 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 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 2011 was $212.5 million, which was the value of the electric power consumed by the municipalities during the fiscal year. The amount of $197.0 million for Contributions in Lieu of Taxes and Other shown on *Appendix II, Income Statement,* is the sum of the CILT credit for fiscal year 2011, plus the annual payments for the three previous year's unpaid CILT, plus certain subsidies and an annual amortization cost described below. During fiscal year 2011 the Authority was credited with $99.1 million in payments and services for the current year's obligations, the difference of $113.4 million will be carried forward for payment by the Authority over a maximum of three fiscal years. In fiscal year 2011 the Authority also made annual installments of $5.9 million, $24.9 million and $19.1 million towards the unpaid CILT balances from fiscal years 2008, 2009 and 2010 respectively; the installment for fiscal year 2008 completed the Authority's outstanding CILT obligations for that year. At the end of fiscal year 2011, the unpaid CILT balance totaled $176.5 million. The deferred CILT balance has grown steadily since the end of fiscal year 2007 when it was $34.3 million.

The Contributions in Lieu of Taxes and Other for fiscal year 2011 includes $38.8 million for the hotel subsidy, the rural electrification and irrigation subsidy, and the residential fuel subsidy, which are discussed in the *Rates* section, and a payment of $9.2 million to amortize the outstanding line of credit used in the settlement of the lawsuit by the municipalities.

In December 2011 the Commonwealth enacted legislation that clarified the scope of CILT by removing the electrical consumption by municipalities currently used to subsidize revenues from for-profit activities, rental property generating income, and activities involving an entrance fee. The Authority is installing additional meters to track this consumption and anticipates its collections will increase by $15 million in fis-

cal year 2013, with incremental collections of $5 million per year through fiscal year 2016. The Authority has adjusted the projected municipal energy consumptions for fiscal years 2013 through 2016 and forecasts the CILT and Other costs will be $265.1, $240.3, 228.5, $223.8, and $220.2 million for fiscal years 2012 through 2016, respectively. Based on the its projected budgets and the CILT amounts, the Authority plans to meet its forecasted current year obligations through fiscal year 2016, however, during this period the accumulated deferred CILT balance discussed above will not be reduced. If municipal electricity consumption drops more than predicted or the price of power declines significantly the calculated CILT obligation may revert to the prior five-year moving average of the contributions in lieu of taxes paid to the municipalities collectively, as discussed above.

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 affect 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, the Authority was required to establish by January 2010 the technical criteria and tariffs that would 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 Authority anticipates the wheeling tariffs will be in effect during the first quarter of fiscal year 2012. 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.

During fiscal year 2011 the Authority incurred only administrative costs associated with the Economic Incentive Act. The Authority estimates, however, the costs will total $70 million in the five years ending in fiscal year 2016.

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 Authority's actual and forecasted capital expenditures for fiscal years 2011 through 2016 are summarized by category in *Appendix VI, Capital Expenditures.* The projected expenditures as shown in *Appendix X, Details of Capital Improvement Program,* are 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 2012 through 2016, as well as those realized in fiscal year 2011, are presented in *Appendix VII, Sources of Funds for Capital Expenditures.*

In the last quarter of fiscal year 2012 the Authority plans to issue two bond series amounting to $650 million. The proceeds of Series 2012A bonds will be used to finance portions of the Authority's CIP, repay lines of credit issued by the GDB for certain principal and interest payments due under the 1974 Agreement and provide capitalized interest for a three year period. The proceeds of Series 2012B bonds will be used to refund Power Revenue Bonds Series II. As shown in Appendix VII, the Authority plans additional financings in fiscal years 2013, 2015 and 2016, principally to fund the Authority's CIP and other purposes.

As of June 30, 2011, the Authority had $7,780,890,000 in Power Revenue Bonds outstanding. (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, 2011 was 147% exceeding the 1974 Trust Agreement's 120% requirement.

INTERIM FINANCING

Lines of Credit and Notes Payable

As of the end of fiscal year 2011 the Authority had three lines of credit and three term loans that are financed through a large commercial bank.

Two of the term loan 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, 2011 the balance was $29.9 million, of which $20.2 million is considered long-term; this note matures in June, 2014

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 $41.5 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, 2011 was $10.8 million of which $4.9 million 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. This note payable matures on November 30, 2013.

The third term loan is for $25.4 million, intended for the restoration of the Isabela Dam. The outstanding balance as of June 30, 2011 was approximately $750,000. This line of credit expires on June 30, 2018. The Authority expects to be reimbursed by the Commonwealth Government for any payments made for this term loan.

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, 2012. As of June 30, 2011 the entire line of credit was available for withdrawal.

The Government Development Bank offered a line of credit of $35 million in reference to the cancelled Gasoducto del Sur project, these assets were transferred to another government agency. As of the end of the fiscal year 2011, $26.5 million had been withdrawn. This line of credit expires on August 17, 2011.

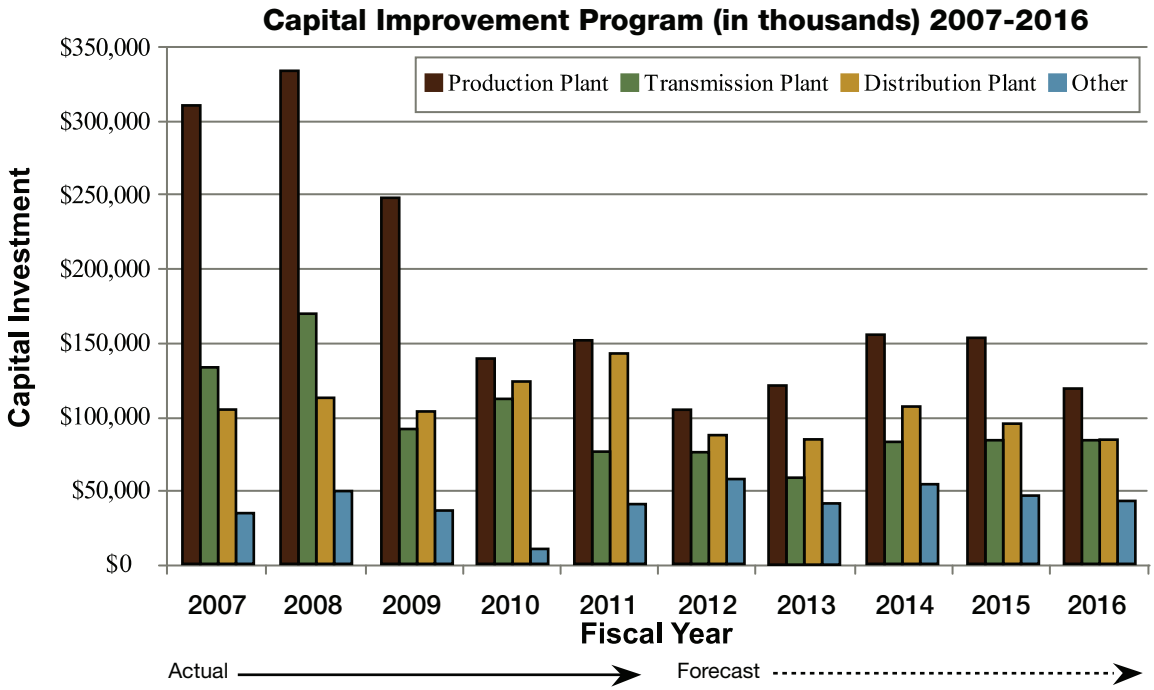
During fiscal year 2011 the Authority and a large commercial bank initiated a $150 million line of credit to be used for fuel financing. The line expires in June, 2012. As of the end of the fiscal year the line of credit had been exhausted.

In addition, the Authority has a line of credit of $150 million with the Government Development Bank to be used, if needed, for Basis Swap Collateral. The entire line of credit was available as of the end of fiscal year 2011.

In summary, as of the end of fiscal year 2011 the Authority's credit lines totaled $360.4 million with approximately $183.2 available for withdrawal and a $40.6 million notes payable balance in which $25.1 million is considered long-term. These figures do not include a PREPA.Net loan used in the acquisition of Ultramarinas de P.R.

CAPITAL IMPROVEMENT PROGRAM

The fiscal year 2012 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 2012 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 2016. Subsequent to developing the Revised Current Forecast discussed in the *Current Forecast* section, the Authority revised its five year CIP. The fiscal year 2012 budget was unaffected as the revisions focused on a net reduction of $55.8 million in fiscal year 2013, with other adjust-



ments principally in fiscal year 2015. The CIP revisions resulted in an overall reduction of the five year CIP budget through fiscal year 2016 from $1,774.7 million to $1,718.9 million. The CIP budgets were subsequently adjusted in March 2012, without affecting the overall total annual budgets; the adjusted CIP is basis of the discussions in this amended report.

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 Authority's capital expenditures reached a peak in fiscal year 2008 when construction of the Authority's two newest production plant projects, San Juan Units 5&6 and the new combustion turbines at Mayagüez, were in their final phases. The capital expenditures in fiscal year 2009 were 29% less than the previous year's. During fiscal year 2010 the capital expenditures of $387.0 million were 16% less than the actual expenditures in fiscal year 2009.

Capital expenditures were projected to decline even more in fiscal year 2011 with a budget of $300 million. Actual capital expenditures during fiscal year 2011 were $411.6 million, which were 37% above the budget. Over the ten year span of fiscal years 2002 through 2011 the Authority's average annual capital expenditures was $482 million, without adjusting for inflation. During this period the Authority made significant investments in expanding its generation base, as well as its transmission and distribution systems. Consistent with the recent downward trend, the capital improvement program expenditures in fiscal year 2011 were more than 14% below the previous ten year average. During the next five fiscal years the Authority plans to reduce its average level of annual capital expenditures to $343.8 million, which is 29% less than the previous ten year average. The CIP budgets in million of dollars are projected to be $326.5, $300.0, $392.6, $372.7, and $326.8 for fiscal years 2012 through 2016, respectively. The figures do not include the 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 2011. During the course of the year the Authority occasionally reallocates certain budgets, staying within the total frame work. The budget amounts shown in the table do not reflect any reallocations.

BUDGETED FY 2011 CIP TO ACTUAL CIP AND FY 2012 CIP BUDGET

(in thousands)

	2011 Budget	2011 Actual	2011 Over Budget	2012 Budget
Production	$ 109,799	$151,175	$ 41,376	$ 104,340
Transmission	67,420	77,734	10,314	76,110
Distribution	80,348	142,869	62,521	87,205
Other	42,433	39,797	(2,636)	58,845
Total	***$ 300,000***	***$411,575***	***$ 111,575***	***$ 326,500***

As indicated above, the Authority's CIP budget for fiscal year 2012 is 20% less than the previous year's actual expenditures. The CIP budget is consistent with the Authority's objectives to reduce capital expenditures. For a perspective on the size of the projected CIP for the five years ending in fiscal year 2016, which is $1,718.9 million, this amount is approximately 16% less than the total actual CIP expenditures for the five year period ending in fiscal year 2004, before the capital expenditure growth during fiscal years 2005 through 2009.

During fiscal year 2012 the Authority plans to contribute $132.5 million to the Capital Improvement Fund, principally relying on the proceeds from the projected bond financing in April 2012; this contribution is 41% of the Capital Improvement Program budget for the year. As shown in *Appendix II, Income Statement,* the projected level of internal funding is scheduled to decline in the remaining four fiscal years ending in 2016, with the contributed amount of funding averaging 6% during that period. Even excluding fiscal year 2012, the projected level of funding is above the Authority's recent performance, when it contributed 3% of the CIP during the five years ending with fiscal year 2011. Funding for the *Capital Improvement Program* is discussed further in the *Capital Improvement Fund* section below.

The first year of the Authority's five-year Capital Improvement Program is included in the Annual Budget of Current Expenses and Capital Expenditures which is reviewed and approved by the Consulting Engineers prior to the beginning of each fiscal year. The current CIP through fiscal year 2016 includes funds for the planned conversions to firing natural gas at all but four of its steam-electric production units, plus three combustion turbine units and two combined cycle units. As discussed in the *Capacity and Energy Resource Planning section,* providing natural gas to the converted units, except Costa Sur Units 5 & 6 that will be supplied during fiscal year 2012, will require an extensive gas supply infrastructure that was still in development during fiscal year 2011. The Authority plans to confirm its gas supply strategy and establish its funding structure during fiscal year 2012.

We believe that the moneys shown in the CIP for extensions and improvements to the System over the forecast period are reasonable. 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 Capital Improvement Program chart shows the trends and relative values of these groups over the five-year budget period.

PRODUCTION PLANT

The CIP for fiscal year 2012 includes $104.3 million for production plant related projects. These projects are broadly grouped in two classifications: expansion projects - $4.0 million and rehabilitation projects - $100.3 million. The latter group, however, includes projects associated with dual fuel conversion to include natural gas, as well as environmental related scopes of work.

As discussed in the *Capacity and Energy Resource Planning* section, the planned production plant expansion program for fiscal year 2012 is the installation of two wind turbine units.

The principal focus for rehabilitation projects is the major refurbishment work planned for the Authority's operating production plants during scheduled major overhauls and plant system upgrades. A representative scope of these projects is discussed in the *Production Plant* section. For example, these activities include the work planned for the major overhaul at Aguirre Unit 1, the upgrade and expansion of the demineralized water treatment plant at the Costa Sur station, the boiler overhaul and convective section modifications for gas firing at Costa Sur Units 5 & 6 and the refurbishment of the turbine driven feed pumps at Costa Sur Units 5 & 6. 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 CIP for fiscal years 2012 through 2016 includes $90.2 million for the conversion to dual fuel firing capability, i.e. fuel oil and natural gas, at eight steam plant units: Aguirre Units 1 & 2, San Juan Units 7, 8, 9 & 10 and Palo Seco Units 3 & 4; an additional $12 million is budgeted fiscal year 2017 to complete the conversions at San Juan Units 7, 8, 9 & 10. In addition to Costa Sur Units 5 & 6, which were converted in fiscal year 2011, the planned total will be gas firing capability at its four largest steam units plus six steam units in the San Juan metropolitan area. Fuel conversions at the last four steam plants (Costa Sur Units 3 & 4 and Palo Seco Units 1 & 2) are not anticipated since each is only 85 MW capacity and the Authority can met its generation requirements with these plants operating at low capacity factors. If the Authority subsequently decides to install dual fuel capability at any of these four steam units, it can be accomplished at relatively modest costs and will be addressed in a subsequent CIP. The CIP for fiscal years 2012 through 2016 also includes $17.1 million for converting the three Cambalache combustion turbines and the two

San Juan Units 5 & 6 combustion turbines to firing natural gas, in addition to distillate.

The Authority has identified projects within the rehabilitation category that are for pollution control, or for environmental issues, that have a total value of $13.9 million for fiscal year 2012. 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 2012 includes $76.1 million for transmission plant related projects. Expansion projects are budgeted at $52.6 million and rehabilitation projects have a budget of $23.5 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 230/115 kV transmission center in Ponce, the new 115 kV GIS transmission center at San Juan steam plant, the new 38 kV underground projects in various municipalities around the island, and the new 115/38 kV transmission center at Hato Tejas.

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 2012 is $87.2 million and is comprised of $18.6 million for expansion projects and $68.6 million for rehabilitation projects.

The distribution expansion projects include new substations, such as the 13.2 kV substations at Hato Tejas, Rio Bayamón, Santa Isabel, and Cayey. 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 in this category is directed to the purchase of remote read meters, which accounts for more than 22% of the distribution budget. 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 2012 totals $55.0 million. This category is composed of $18.7 million for general land and buildings and $36.3 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 alternative energy sources. 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. The budget includes funds for the rehabilitation of one of the Authority's major offices, the Luchetti building in San Juan.

The equipment group is made up of five subgroups. The CIP for fiscal year 2012 includes $220,000 for office equipment, with only modest budget increases in the following fiscal years through 2016. In fiscal year 2012 the computer equipment budget is $23.5 million; $20.0 million of that budget is directed to completing the first phase of a new client service system. Other equipment subgroups are transportation equipment (land and air) at $8.4 million, communications equipment at $0.4 million and other equipment at $3.7 million.

PRELIMINARY INVESTIGATIONS

The final category in the CIP is for preliminary studies and surveys. The fiscal year 2012 budget for these activities is $3.8 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 contri-

butions from both the Authority, based on annual actuarial valuations, and plan members. The Retirement System's independent actuary prepared an actuarial valuation for fiscal year 2010 and the results showed that "The valuation results indicate that the combined employer and member contribution rates are sufficient to fund the normal cost for all members and the unfunded accrued liability." The valuation report also states that the actuarial assumptions meet the parameters for the disclosures under Government Accounting Standards Board Statements No. 25 and 27.

The Retirement System's unfunded accrued liability had increased from $980.3 million as of the end of fiscal year 2009 to $1,401.7 million as of the end of fiscal year 2010.

For future calculations the Actuarial assumptions are: an 8.5% rate of return on investments; projected salary increases of 4.1 – 5.4% depending on age; 2—8% cost of living adjustments depending on the amount of benefit with a minimum of $25 per month and maximum of $50 per month; and 3% inflation.

The following table further summarizes the status of the Authority's Pension Plan for the year ending June 30, 2010:

AUTHORITY'S PENSION PLAN	
Number of Active Members	8,808
Number of Retired and Disabled Members and Survivors	11,270
Annual Benefits	$181,411,868
Actuarial Value of Assets (in millions)	$1,414.7
Actuarial Accrued Liability (in millions)	$2,816.4
Unfunded Actuarial Accrued Liability (in millions)	$1,401.7
Estimated Covered Payroll (in millions)	$357.4
Recommended Contributions for Fiscal Year Ending 2012	
Total Contribution Rate:	
Normal	9.6%
Unfunded Accrued Liability	24.5%
Total Employer Contribution Rate	34.1%
Average Member Contribution Rate	10.3%
Authority Contribution Rate	23.9%
Amortization Period	30 years

INVENTORIES AND OTHER PROPERTIES

As part of the Executive Directorate, 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. Included in the Material Management's responsibilities are purchasing and inventory control, under the Warehouse subdivision.

The Warehouses subdivision utilizes 32 warehouses and manages an extensive inventory. At the end of fiscal year 2011 the inventory was worth $175.8 million of which $67.2 million was transmission and distribution material and $108.6 was 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 the inventory 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.

INSURANCE

The Risk Management Office, within 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 2011 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 and fiber optic 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 Public Liability, Commercial Auto Policy-PREPA, Personal Auto Policy-Employees, Crime, Directors and Officers Liability, Fiduciary Liability, Employment Practices Liability, Aviation, Hull and Hull Risks, Personal Accident and Health, Owner Controlled Insurance Program (OCIP) Rolling Wrap-up, and Open Cargo. Among the policies included in the OCIP are; Commercial General Liability, Builders Risk Installation Floater, Pollution Liability and Professional 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 deductible 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, with a $25 million deductible, are covered by another policy that provides an additional $250 million in coverage. The Boiler and Machinery policy has a business interruption sub-limit of $10 million covering the costs from the first thirty days of the interruption. The public liability coverage remains at $75 million with the Authority holding $1 million self-retention and $1 million deductible/ $3 million annual aggregate deductible.

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.*

A report was issued in October 2009 by an independent risk management consultant in compliance with Section 706 of the Trust Agreement. After reviewing the recommendations in May 2010 the Authority made a number of changes which were effective during fiscal year 2011 to their Insurance Program,. Within the All Risk Property Policy the Authority's retention under the $550 million of windstorm damage coverage was reduced from $50 million to $25 million. The pollution and terrorism perils that are covered by the Property Program remain unchanged at $250 million per pollution event with the Authority responsible for the retention of $300 million. The deductible on the Authority's $550 million Boiler and Machinery Policy is $10 million per occurrence. Coverage under the Directors and Officers Liability Policy is an annual aggregate of $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 $21.8 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 $102.9 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, 2011 the Authority had been reimbursed a total of $301.3 million for losses associated with the two Palo Seco events and the Authority was continuing to negotiate the recovery of another $28.1 million.

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 moneys 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 status of the Self-insurance Fund and the Consulting Engineer's recommendations concerning contributions.

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 fires at the Palo Seco Power Plant during fiscal year 2008 caused damages estimated to total $339.1 million, of which insurance payments to the end of fiscal year 2011 amounted to $301.3 million.

The specific utilizations of money from the Reserve Maintenance and Self-insurance Funds are 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 2011, the Reserve Maintenance Fund's balance was $15.7 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 increased costs associated with the loss 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 years 2009, 2010 and 2011. At the request of the Authority, the Consulting Engineers agreed that the moneys would instead be used to reduce the $53 million inter-fund debt; at the end of fiscal year 2011 this inter-fund debt was approximately $38 million.

The Consulting Engineers recommends the Authority need not deposit any monies into the Reserve Maintenance Fund during fiscal year 2012.

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 2011 the balance of the Self-insurance Fund was $84.6 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 years 2009, 2010 and 2011 the Authority deposited $10 million per year to the fund in accordance with the Consulting Engineers recommendations.

For fiscal year 2012 the Consulting Engineers recommends that the Authority deposit $5 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 Capital Improvement Program (CIP). (For further discussion, refer to the *Annual Budget* in the *Financial* section.) The budget for fiscal year 2011 projected that the CIP expenditures would be $300.0 million, of which $69.1 million to the Capital Improvement Fund would be generated internally. The actual CIP expenditures for fiscal year 2011, however, totaled $411.6 million, of which $17.2 million, or 4%, was financed internally through the Capital Improvement Fund. In the six fiscal years from 2006 through 2011 the average level of internal funding for the CIP was just above 5%; this low average would have been much lower save for the contributions

made in 2006 and 2010. The levels of deposits to the Capital Improvement Fund over the three years through fiscal year 2009 were 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. While short-term debt was refinanced, the available internal contributions in fiscal years 2010 and 2011 reflect the sensitivity of this funding to the compliance with discretionary budgets and the Authority's obligations of Contributions in Lieu of Taxes.

For fiscal year 2012 the Capital Improvement Program budget is $326.5 million, of which $131.2 million, or 40%, is projected to come from internal funds; the principal source of funds will be the bond financing planned for April 2012. The internally generated funds portions of the CIP for fiscal years 2013 through 2016 are projected to be 9%, 4%, 6% and 8%, respectively. Including the high amount scheduled for fiscal year 2012, the forecasted amount of internal funds will average 12% of the CIP over the five years ending in fiscal year 2016.

The table below shows the Authority's actual deposits to the Capital Improvement Fund for the most recent five fiscal years compared with that which was budgeted.

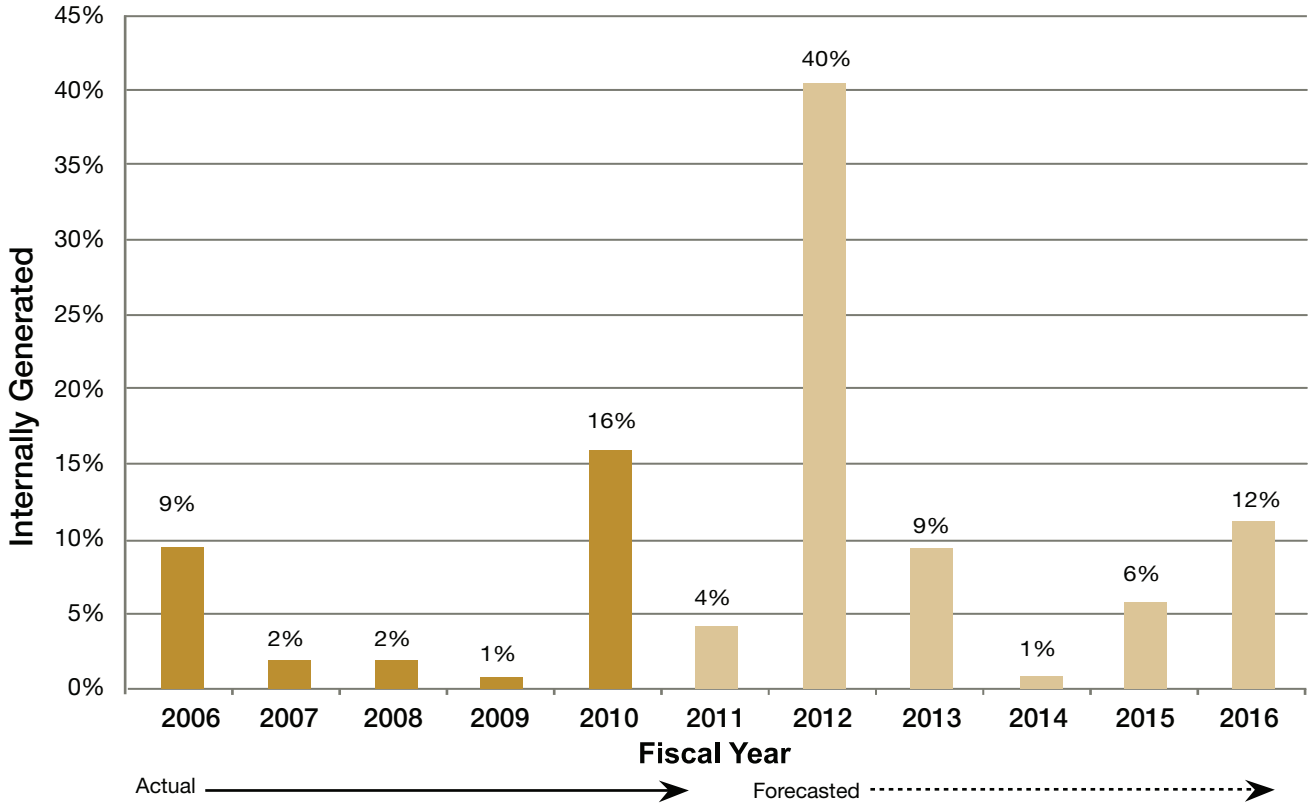
CAPITAL IMPROVEMENT FUND

Fiscal Year	Amount Budgeted	Amount Deposited	Difference
2011	$ 69.1	$ 17.2	($ 51.9)
2010	$ 0.0	$ 63.4	$ 63.4
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)

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 2006 and those forecasted through 2016.

Internally Generated Funds Portion of Financing Sources
Fiscal Years 2006-2016



HUMAN CAPITAL

HUMAN RESOURCES

On June 30, 2011, the Authority had a total workforce of 8,659 employees: 8,580 permanent employees and 79 temporary or probationary employees who had been employed by the Authority for less than 12 months and two of whom were classified as emergency employees. The total number of employees on June 30 2011 reflects a net decrease of 140 employees. However, during the fiscal year the number of permanent employees declined by 216 whiles the number of temporary employees increased by 76. The Authority anticipates that the number of permanent employees will continue to decline by several hundred through fiscal year 2012. On June 30 2010 the Authority had 8,799 employees; of which 8,796 were permanent and 3 were temporary.

Subsequent to the realignment of the Authority's directorates that were made during fiscal year 2010 the Authority reorganized the Generation, Transmission & Distribution Directorate with the appointment of a Director of Transmission & Distribution, with the responsibility for the operation of the transmission & distribution system. This change brought the number of Directorates to nine; they are the Executive Directorate, the Generation Directorate, the Transmission & Distribution Directorate, the Law Directorate, the Planning and Environmental Control Directorate, the Finance Directorate, the Client Services Directorate, and the Human Resource and Labor Affairs Directorate. Ninety–three percent of the Authority's employees were employed in one of the following four directorates: 3,768 worked in the Transmission & Distribution Directorate for a total of approximately 44% of the Authority's employees; 2,101 employees worked in the Generation Directorate for a total of 24% of the Authority's employees; the Client Services Directorate employed 1,564 persons or 18% of the Authority's workforce; and 602 employees worked in the Executive Directorate, constituting approximately 7% of the Authority's workforce. An additional 624 persons were employed in one of the five other directorates or by the Governing Board.

In addition to the realignment and streamlining of operations as described above the Authority has reduced their cost by suspending some allowances, by suspending professional compensation premiums, by the reclassification of certain management positions to a lower salary level, and by freezing the compensation of high level employees. In September of 2009 the Authority implemented a major change in the manner in which medical insurance would be provided for retirees and their spouses. Before September 1, 2009 an employee retiring with 25 years of service received medical care insurance for themselves and their spouse. An employee retiring with less than 30 years of service after September 30, 2009 was not eligible for a lifetime benefit of medical insurance for themselves or their spouse. An employee retiring after that date with more than 30 years of service received a lifetime benefit of medical insurance but received no medical insurance coverage for their spouse. The Authority however has a plan whereby these former employees with 30 years of service can purchase coverage for their spouse. The Authority has negotiated an extension of the firm fixed price for the provision of medical care for retirees and eligible spouses through December of 2012.

The Authority prepares its employees for their job assignments by providing a wide range of training programs and refresher training programs. The Human Resources Directorate provides the Authority's employees with training in the areas of safety, health, and computer usage. The training programs offering 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.

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 2011 four different unions represented 6,027 of the Authority's employees or 70% of the Authority's workforce. The other 2,632 employees are members of the executive, managerial, and administrative staff. The terms of employment for these 2,653 employees are not established by a collective bargaining agreement. The figures for fiscal year 2010 are similarly proportional; 6,146 employees represented by unions, (70% of the workforce), and 2,653 in executive, managerial, and administrative positions. The Authority replaced very few of the more than 200 former employees who retired or left its employ for other reasons during fiscal year 2011.

In an ongoing effort to further improve the efficiency with which their services were provided the

Authority continued to evaluate additional structural reorganization. The following paragraphs describe the status of the renegotiation of the Authority's collective bargaining agreements. During these negotiations the Authority will propose to reaffirm certain management rights, clarify job descriptions, and to modify the code of conduct in a manner that will facilitate the management of its operations and to use these concessions as the basis for a monetary offer. The Authority's practice has been to make a renegotiated agreement effective on the date following the expiration of the predecessor agreement but to make any monetary change effective on the date the agreement was made; it is not back calculated to the date the agreement's termination date. In 2008 the last of the four unions agreed to an entry level wage freeze for new employees. In an effort to educate employees the Authority plans to publish a benefits statement summarizing annual vacation, sick, and holidays, which total 72 days in all, and the costs of medical and pension benefits.

The Authority negotiates collective bargaining agreements with four unions. The labor agreements establishing wages, hours, and conditions of employment for three of these unions terminated during fiscal year 2011 .The Authority began the renegotiation of these three agreements with union representatives of the Pilots, (UPAEE), the Independent Professional Employees Union, (UEPI), and Insular Union of Industrial and Electrical Construction Workers, (UTICE), during fiscal year 2010. Early in fiscal year 2013 the labor agreement covering the employment of workers represented by the Union of Workers of Electrical Industry and Irrigation of Puerto Rico, (UTIER), will terminate.

The Authority has begun the renegotiation of a collective bargaining agreement with the Electric Energy Authority's Pilot Union (UPAEE). The four-year agreement, which established wages, hours, and conditions of employment for the Authority's six pilots, terminated on July 2, 2010. During the last year of the agreement the pilots received a 4% increase. At the end of fiscal year 2011 following more than a year of negotiations the union understood that the Authority could not offer a wage increase at the present time and was continuing to negotiate. It was unlikely that this agreement would be concluded before the commencement of bargaining with UTIER, the largest of the Authority's unions. The Authority is seeking a four year agreement with UAPEE.

Negotiations for a new collective bargaining agreement between the Authority and the Independent Professional Employees Union (UEPI), which represented 368 of the Authority's employees, were continuing at the end of fiscal year 2011. The Authority has been unable to obtain the concessions that would justify a monetary offer. The Authority is seeking a four year agreement.

The labor agreement with the Insular Union of Industrial and Electrical Construction Workers, (UTICE), was a three-year agreement, which terminated on January 26, 2011. UTICE represented 904 of the Authority's employees on June 30, 2011. As with the negotiations with the other unions the Authority has been unable to obtain the concessions that could be quantified as justification for a monetary offer. The Authority is seeking a five year agreement with UTICE.

The agreement between the Union of Workers of Electrical Industry and Irrigation of Puerto Rico, (UTIER), and the Authority will terminate on August 24, 2012. At the end of fiscal year 2011 UTIER represented 4,749 of the Authority's employees. These employees received a 4% wage increase in August 2011 for the final year of the agreement with the Authority. The agreement froze the entry level pay rate for newly hired employees during its four-year term of the agreement. The Authority will formally begin the renegotiation of the agreement covering these employees early in calendar year 2012.

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 31, comprised largely of safety and health professionals, provides assistance to managers and supervisors in the day-to-day implementation of safety and health programs. Twelve of the 31 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 ten Safety and Industrial Hygiene Officers,

of these one is assigned to each of five generating stations, Central Aguirre Steam, Aguirre Combined Cycle, Central Costa Sur, Central Palo Seco, and Central San Juan. Five Safety and Industrial Hygiene Officers are based in Santurce, 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 Mayaguez. Two Health and Safety Officers are based in the Authority's Santurce office and are assigned as needed 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) and initial and refresher training in hazard recognition, personal protective equipment, and hazard communication at facilities throughout the Commonwealth to more than 2600 of the Authority's employees each year. The Division has a performance recognition program for units and Directorates whose employees work in a high risk environment and a second recognition program for those working in office environments where there is less risk of a work related injury or illness.

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; during calendar year 2010 safety training focused on effective electrical grounding procedures, hazard communication, natural gas safety briefings for generating station employees, control procedures for abating hazardous conditions, and on the specification for and procurement of personal protective gear. Approximately 4,000 employees participated in training for working in confined spaces, respirator use, excavation safety, office safety, welding safety, fall protection, 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.

In calendar year 2010, the Authority reported to OSHA that its employees worked a total of 14,850,091 hours and sustained 1,339 incidents of work related injury or illness that were recordable in accordance with the OSHA's requirements. There were four fatalities during calendar year 2010, three of which were the result of an electric contact or high voltage discharge. Six of the 12 other serious incidents that had the potential of causing death or serious injury were the result of an electrical contact The frequency with which the Authority's employees reported work-related injuries or illnesses in calendar year 2010 was 18, slightly higher than the 17.4 recorded for 2009. This frequency continues to be more than four times the frequency rate experienced by mainland utilities.

For the past seven years the Authority and other Puerto Rican public corporations have been 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 2010, the Authority was cited eleven times for violating OSHA regulations, however no fines were imposed.

The sixty-seven employees of the Occupational Health Division, within the Human Resources and Labor Affairs Directorate, are responsible for providing first aid, medical treatment, training, and administrative services to employees from the reported onset of a work related injury or illness until the employee returns to work, is reassigned, or reclassified. They provide a range of health related activities and training programs. In the past year they completed more than 3,000 medical and psychological evaluations. An employee's initial contact with this division 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 Monacillo, Caguas, and Ponce. The other four dispensaries are located at the Aguirre, Costa Sur, Palo Seco, and San Juan steam electric plants. The Authority's registered nurses provided first aid or other treatment on more than 23,310 occasions to employees during calendar year 2010. Eighty-six percent of the treatments were for a condition that was classified as non-occupational.

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 have the authority to determine when the employee is capable of returning to work. A long-term goal of the Authority has been to obtain the cooperation of Fondo's representatives in expediting the scheduling of the care being provided to their injured or ill employees. The Authority reports increased cooperation from Fondo. In certain areas they are releasing the Authority's employees, those with minor injuries, to return to work following five days of recuperation. During 2010 the Authority's representatives met with Fondo administrators to review the case management of employees being treated by Fondo.

Since 1995 the Authority has had a random drug-testing program, which has been implemented in steps. The random drug-testing program applies to 5,481employees in safety sensitive positions. During calendar year 2010 approximately 1,321 of the Authority's employees were randomly tested. Thrty two employees tested positive and were referred to a three month long treatment program, where they received treatment and counseling. During the calendar year a total of 56 employees received counseling for some form of substance abuse. An employee who tests positive for drugs three times may be terminated.

In 74% 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. During 2010 twenty-six percent of employees who sustained a work related injury or illness reported for work on the day following the work related illness or injury. Of those reporting for work the day after an injury or illness, almost half were reassigned to another job or placed on light duty and technically were classified as a lost time case. Per OSHA recordkeeping rules, about 87% of those sustaining a work related injury or illness were incapable of performing their normal job function on the day following the incapacitating event. This ratio is similar to ratios recorded by the Authority over the past several years. During 2009 those employees reassigned to another position or placed on restricted duty were so assigned for an average of 31 days; the average duration of the reassignment or restricted duty in calendar year 2010 increased to 53 days.

During calendar year 2009 an employee sustaining a work related injury or illness was away from work on average 94 days if he was unable to report to work on the day following the incident. An injured employee who is at home recuperating following a work related incident continues to accrue vacation, sick leave, and is eligible to receive a Christmas bonus even though the employee may not have worked during the year. Salary continuation extends for up to two years at full pay. For calendar year 2010 the average number of lost workdays declined from 94 to 80 days. On December 31, 2010 there were 499 employees recuperating at home following a work related incident. This is 58 fewer than were reported to be recuperating at home at the end of 2009.

LEGAL AFFAIRS

The twenty-two attorneys of the Legal Affairs Directorate are 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 2011.

The breach of contract litigation between Abengoa, Puerto Rico, S.E. and the Authority continued in discovery in Superior Court, Court of First Instance in Puerto Rico. The suit dates to an action in May 2000 when Abengoa, the prime contractor for the construction of two combined cycle units at San Juan Steam Plant, terminated their contract and left the construction jobsite; Abengoa alleged $18 million in losses and have claimed as one basis that the Authority had not obtained the permits from the EPA that were necessary for the construction to proceed. In 2011 the Authority estimated their losses as a result of Abengoa's alleged breach of contract to be approximately $250 million. In October 2007 the lawsuit was certified as complex litigation necessitating specialized treatment. As discussed in the *Production Plant* section, San Juan Units 5 & 6 went into commercial operation in October 2008. During fiscal year 2011 Superior Court appointed a Special Commission headed by a Puerto Rican engineer to settle the case within the next four years.

In June 2006 seven plaintiffs filed suit alleging that the Authority had overcharged clients approximately $50 million for electricity between 1999 and 2003. Additional plaintiffs joined the suit and claims against the Authority grew to more than $700 million. The Authority was successful in defeating the plaintiffs attempt to reclassify their suit as a class action. The matter had nuisance value to the Authority and was disposed of for $5,000 per plaintiff during fiscal year 2011.

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. During fiscal year 2011 work was continuing; the final phase of the project is scheduled for completion in 2014.

Five 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 claimed damages of more than $18 million against the co-defendants, the manufacturer and their Puerto Rican partner. During fiscal year 2010 the Brazilian battery manufacturer declared bankruptcy. The Authority continues to litigate this case against the Puerto Rican partner. The bonding company standing behind the Brazilian manufacturer and the Puerto Rican partner was failing in 2011; making a significant recovery of the Authority's claim dubious.

The Authority has increased its efforts to eliminate the theft of electricity. Electricity theft is occurring across client classes, throughout the Commonwealth and has been identified as having a material impact on the Authority's operations. During 2011 the Authority assigned eleven attorneys as administrative law judges to decide cases of persons or entities suspected of electricity theft. Administrative law judges have the authority to make summary judgment to recover the revenue associated with the theft and to impose fines of up to $10,000. Five of the seven attorneys responsible for prosecuting the cases on behalf of the Authority are former prosecutors, working as contract employees who receive a percentage of the penalty assessed. In an effort to expedite the processing of a growing backlog of electricity theft cases, the resolution of cases involving less than $5,000 of suspected theft may be processed in the regional offices of the Client Services Directorate. The client is required to pay 50% of the determined value of the electricity that was stolen at the conclusion of the hearing. A repayment schedule for the balance of the amount assessed is established during the hearing. Recovery per the scheduled repayment plan is the responsibility of the Client Services Directorate. During fiscal year 2011 the Authority adjudicated 1,278 cases of electricity theft in their Santurrce offices and assessed $9.85 million in settlement of these cases. An additional $3.5 million was assessed in settlement of cases in which the value of the electricity theft was determined to be less than $5,000. In summary during the past fiscal year these procedures assessed a total of $13.4 million in repayment for the theft of electricity There were 2201 cases pending resolution on June 30, 2011. The Authority concludes that the publicity given their ongoing aggressive actions to uncover and prosecute energy theft is having a ripple effect which discourages continued theft by those not yet detected.

The Authority reports that Power Technologies Corp filed suit against the Authority over the Authority's decision not to proceed with a project to construct an electric generating plant in the Mayagűez area continues in discovery. Power Technologies Corp alleges that the project was cancelled without justification; they are seeking recovery of damages of more than $51 million.

The Caribbean Petroleum Corporation's (CAPECO), fuel storage depot in Bayamón caught fire in October 2009. The Authority had residual fuel oil and distillate stored at the depot. The fire was extensive; it shut down the depot and caused some amount of air and water contamination to the adjacent area. The Authority and numerous other parties have been named in suits filed against CAPECO. Early in fiscal year 2011 CAPECO filed for bankruptcy protection, staying the suits against it. In December 2010 CAPECO sold its assets to Puma Energy Caribe who commenced the reconstruction of the damaged facility and environmental remediation. At the end of fiscal year 2011 the suit against the Authority and others continued in the discovery stage of what could be a lengthy process, but one not material to the Authority.

During fiscal year 2011 the Authority closed 86 civil suits that had been brought against them. These suits claimed damages of more than $157 million; they were settled for less than $2 million, less than 1.3% of the damages claimed.

SUPPLEMENTARY INFORMATION

PREPA SUBSIDIARIES

The Authority' organization includes two component units—Puerto Rico Irrigation Systems and PREPA Holdings LLC. Both were active at the end of fiscal year 2011.

The Puerto Rico Irrigation System operates various legacy portions of irrigation systems on the island. The condensed financial statement for Puerto Rico Irrigation Systems as of June 30, 2011 showed $37.0 million in total assets and the annual revenue as $1.9 million, based on operating revenues of $6.0 million and operating expenses of $4.1 million.

PREPA Holdings, LLC is a subsidiary of the Authority that was created as the holding company for the Authority's four other subsidiaries; these subsidiaries are PREPA. Networks, LLC (PREPA .net); PREPA Utilities, LLC; PREPA Oil & Gas, LLC; and InterAmerican Energy Sources, LLC. The latter three were not operating in fiscal year 2011.

In 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.

In June 2005 the Authority created PREPA Networks, LLC (PREPA.Net) to replace PRIN and market the excess communication capacity of the fiber optic network. PREPA.Net owns, operates and maintains the fiberoptic network that offers next generation telecommunications (NGT) service to carriers, internet service providers (ISPs), and large enterprises. PREPA.net's network has optical technology that is used by service providers to communicate with submarine cable landing stations, wireless network towers and island wide locations.

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. The balance of the loan as of the end of fiscal year 2011 was $9.9 million of which $9.0 million is considered ongterm debt.

In fiscal year 2011 PREPA.net acquired property in Isla Verde for the development of a facility to support its telecommunications business; the facility is scheduled for completion in fiscal year 2014.

PREPA.net's audited financials showed its total assets at the end of fiscal year 2011 were $26.8 million and its net income was $2.7 million.

During fiscal year 2011 the following three subsidiaries were not in operation:

PREPA Utilities was formed to financially participate in, develop, construct and operate industrial projects and other related infrastructure to improve the electric infrastructure of the Authority.

PREPA Oil & Gas was established to provide a mechanism for the Authority to participate in a wide range of financial, commercial and operational projects for fuel supply and infrastructure.

InterAmerican Energy Sources was formed to financially participate in, develop, construct and operate renewable energy source projects and other infrastructure that improve the Authority's electric infrastructure.

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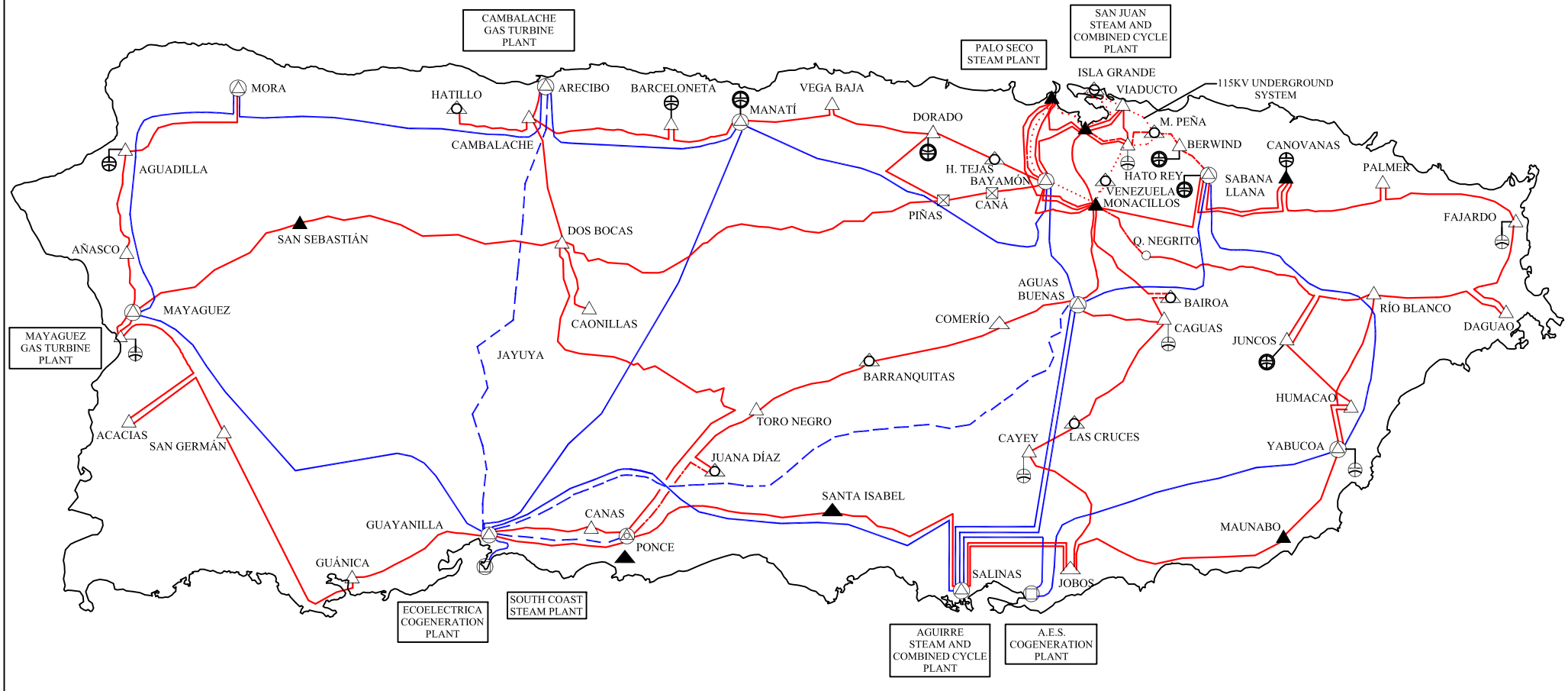
PREPA'S TRANSMISSION SYSTEM
2016



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 2016

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APPENDICES

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APPENDIX I
INTERMEDIATE-TERM FINANCIAL PLANNING FORECAST

	Actual[1]		Forecast											
	2011		2012		2013		2014		2015		2016	
	Amount	Increase %	Amount	Increase %	Amount	Increase %	Amount	Increase %	Amount	Increase %	Amount	Increase %
kWh SALES (000)												
Residential	6,707,486	(4.95)	6,481,399	(3.37)	6,483,906	0.04	6,555,322	1.10	6,662,128	1.63	6,785,571	1.85
Commercial	8,551,434	(2.37)	8,373,903	(2.08)	8,267,383	(1.27)	8,253,160	(0.17)	8,295,016	0.51	8,375,891	0.97
Industrial	2,881,159	(5.45)	2,722,546	(5.51)	2,628,516	(3.45)	2,627,508	(0.04)	2,669,063	1.58	2,737,837	2.58
Public Lighting	280,973	(1.32)	281,744	0.27	280,973	(0.27)	280,973	0.00	280,973	0.00	281,743	0.27
Agricultural	29,216	(2.71)	29,295	0.27	29,216	(0.27)	29,216	0.00	29,216	0.00	29,296	0.27
Others	51,141	(11.18)	51,281	0.27	51,141	(0.27)	51,141	0.00	51,141	0.00	51,281	0.27
TOTAL	18,501,409	(3.81)	17,940,168	(3.03)	17,741,135	(1.11)	17,797,320	0.32	17,987,537	1.07	18,261,619	1.52
CUSTOMERS (12 month average)												
Residential	1,341,291	0.40	1,340,316	(0.07)	1,341,544	0.09	1,342,758	0.09	1,343,959	0.09	1,344,946	0.07
Commercial	129,537	0.25	128,836	(0.54)	128,762	(0.06)	128,747	(0.01)	128,789	0.03	128,902	0.09
Industrial	770	(4.70)	729	(5.32)	706	(3.16)	683	(3.26)	662	(3.07)	641	(3.17)
Public Lighting	2,225	(1.07)	2,215	(0.45)	2,215	0.00	2,215	0.00	2,215	0.00	2,215	0.00
Agricultural	1,300	0.31	1,278	(1.69)	1,278	0.00	1,278	0.00	1,278	0.00	1,278	0.00
Others	3	(25.00)	2	(33.33)	2	0.00	2	0.00	2	0.00	2	0.00
TOTAL	1,475,126	0.38	1,473,376	(0.12)	1,474,507	0.08	1,475,683	0.08	1,476,905	0.08	1,477,984	0.07
kWh PER CUSTOMER												
Residential	5,001	(5.33)	4,836	(3.30)	4,833	(0.05)	4,882	1.01	4,957	1.54	5,045	1.78
Commercial	66,015	(2.62)	64,997	(1.54)	64,207	(1.22)	64,104	(0.16)	64,408	0.47	64,979	0.89
Industrial	3,741,765	(0.78)	3,734,631	(0.19)	3,723,110	(0.31)	3,847,010	3.33	4,031,817	4.80	4,271,197	5.94
Public Lighting	126,280	(0.26)	128,389	1.67	128,389	0.00	126,850	(1.20)	126,850	0.00	127,198	0.27
Agricultural	22,474	(3.01)	22,923	2.00	22,861	(0.27)	22,861	0.00	22,861	0.00	22,923	0.27
Others	17,047,000	18.43	25,640,500	50.41	25,570,500	(0.27)	25,570,500	0.00	25,570,500	0.00	25,640,500	0.27
BASE REVENUE ($000)												
Residential	$ 339,741	(2.54)	$ 328,865	(3.20)	$ 326,496	(0.72)	$ 329,923	1.05	$ 335,042	1.55	$ 340,953	1.76
Commercial	570,142	(2.90)	556,528	(2.39)	551,204	(0.96)	550,256	(0.17)	553,046	0.51	558,438	0.97
Industrial	121,539	(5.73)	112,755	(7.23)	110,881	(1.66)	110,839	(0.04)	112,592	1.58	115,493	2.58
Public Lighting	51,786	(0.75)	51,974	0.36	51,786	(0.36)	51,786	0.00	51,786	0.00	51,928	0.27
Agricultural	1,636	(0.37)	1,693	3.48	1,636	(3.37)	1,636	0.00	1,636	0.00	1,640	0.24
Others	2,182	(11.41)	2,201	0.87	2,182	(0.86)	2,182	0.00	2,182	0.00	2,188	0.27
TOTAL	$1,087,026	(3.03)	$ 1,054,016	(3.04)	$ 1,044,185	(0.93)	$ 1,046,622	0.23	$ 1,056,284	0.92	$ 1,070,640	1.36
FUEL OIL ADJUSTMENT ($000)												
Residential	$ 962,525	11.09	$ 1,172,683	21.83	$ 1,044,226	(10.95)	$ 970,950	(7.02)	$ 935,896	(3.61)	$ 917,339	(1.98)
Commercial	1,194,694	16.98	1,477,490	23.67	1,302,180	(11.87)	1,195,551	(8.19)	1,139,664	(4.67)	1,107,438	(2.83)
Industrial	369,036	14.01	440,454	19.35	381,354	(13.42)	350,595	(8.07)	337,779	(3.66)	333,434	(1.29)
Public Lighting	41,621	20.25	52,370	25.83	46,615	(10.99)	42,872	(8.03)	40,661	(5.16)	39,237	(3.50)
Agricultural	4,503	16.18	5,493	21.99	4,850	(11.71)	4,460	(8.04)	4,230	(5.16)	4,082	(3.50)
Others	6,491	6.64	8,286	27.65	7,370	(11.05)	6,778	(8.03)	6,429	(5.15)	6,204	(3.50)
TOTAL	$ 2,578,870	14.31	$ 3,156,776	22.41	$ 2,786,595	(11.73)	$ 2,571,206	(7.73)	$ 2,464,659	(4.14)	$ 2,407,734	(2.31)
PURCHASED POWER ($000)												
Residential	$ 277,179	(7.41)	$ 279,219	0.74	$ 337,697	20.94	$ 373,171	10.50	$ 426,594	14.32	$ 463,982	8.76
Commercial	342,612	(2.52)	353,879	3.29	421,117	19.00	459,493	9.11	519,474	13.05	560,132	7.83
Industrial	105,472	(5.25)	106,060	0.56	123,327	16.28	134,746	9.26	153,964	14.26	168,648	9.54
Public Lighting	11,842	(0.90)	12,435	5.01	15,075	21.23	16,477	9.30	*18,534*	12.48	19,846	7.08
Agricultural	1,289	(3.66)	1,314	1.94	1,568	19.33	1,714	9.31	*1,928*	12.49	2,065	7.11
Others	1,865	(11.02)	1,985	6.43	2,383	20.05	2,605	9.32	*2,930*	12.48	3,138	7.10
TOTAL	$ 740,259	(4.79)	$ 754,892	1.98	$ 901,167	19.38	$ 988,206	9.66	$ 1,123,424	13.68	$ 1,217,811	8.40
REVENUES ($000)-incl. adj. charge												
Residential	$ 1,579,445	4.29	$ 1,780,767	12.75	$ 1,708,419	(4.06)	$ 1,674,044	(2.01)	$ 1,697,531	1.40	$ 1,722,273	1.46
Commercial	2,107,448	7.53	2,387,897	13.31	$ 2,274,501	(4.75)	2,205,299	(3.04)	2,212,184	0.31	2,226,009	0.62
Industrial	596,047	5.70	659,269	10.61	615,562	(6.63)	596,181	(3.15)	604,335	1.37	617,575	2.19
Public Lighting	105,249	6.59	116,779	10.95	113,476	(2.83)	111,135	(2.06)	110,982	(0.14)	111,011	0.03
Agricultural	7,428	8.34	8,500	14.43	8,054	(5.25)	7,811	(3.02)	7,795	(0.20)	7,787	(0.10)
Others	10,538	(1.01)	12,472	18.35	11,936	(4.30)	11,566	(3.10)	11,542	(0.21)	11,530	(0.10)
TOTAL	$ 4,406,155	6.06	$ 4,965,684	12.70	$ 4,731,948	(4.71)	$ 4,606,036	(2.66)	$ 4,644,369	0.83	$ 4,696,185	1.12

1. Audited

APPENDIX II
INCOME STATEMENT

	2011	2012	2013	2014	2015	2016
REVENUES						
Revenues from Appendix I	$ 4,406,155,464	$ 4,965,684,000	$ 4,731,948,000	$ 4,606,036,000	$ 4,644,369,000	$ 4,696,185,000
Add'l Revenues from Theft Recovery	-	25,000,000	30,000,000	30,000,000	30,000,000	30,000,000
From Sales of Electricity	4,406,155,464	4,990,684,000	4,761,948,000	4,636,036,000	4,674,369,000	4,726,185,000
Residential Rate Stabilization		(70,000,000)				
Other Operating Revenue-Net	16,594,793	-	-	-	-	-
Total Operating Revenue	4,422,750,257	4,920,684,000	4,761,948,000	4,636,036,000	4,674,369,000	4,726,185,000
Other Income-Net	(11,537,045)	5,058,000	5,058,000	5,058,000	5,058,000	5,058,000
Total Revenues	$ 4,411,213,212	$ 4,925,742,000	$ 4,767,006,000	$ 4,641,094,000	$ 4,679,427,000	$ 4,731,243,000
CURRENT EXPENSES						
Operating Expenses	$ 3,705,191,885	$ 4,195,003,000	$ 3,966,771,000	$ 3,832,526,000	$ 3,844,768,000	$ 3,871,801,000
Miscellaneous Interest and Other	-	-	-	-	-	-
Total Current Expenses	3,705,191,885	4,195,003,000	3,966,771,000	3,832,526,000	3,844,768,000	3,871,801,000
Balance to Revenue Fund	$ 706,021,327	$ 730,739,000	$ 800,235,000	$ 808,568,000	$ 834,659,000	$ 859,442,000
1974 SINKING FUND						
Interest on Bonds	$ 378,343,248	$ 172,294,000	$ 332,189,000	$ 358,463,000	$ 364,096,000	$ 347,408,000
Interest on Various P.R.B. Issues[1]	$ (73,565,062)					
Bond Redemption	175,455,000	155,728,000	194,920,000	204,305,000	214,410,000	245,380,000
Reserve Account	-	-	-	-	-	-
Total Sinking Fund Payments[2]	$ 480,233,186	$ 328,022,000	$ 527,109,000	$ 562,768,000	$ 578,506,000	$ 592,788,000
Balance	$ 225,788,141	$ 402,717,000	$ 273,126,000	$ 245,800,000	$ 256,153,000	$ 266,654,000
TRANSFERS						
Reserve Maintenance Fund	-	-	-	-	-	-
Self Insurance Fund	10,000,000	5,000,000	-	-	-	-
1974 Capital Improvement Fund	17,231,481	131,181,000	26,459,000	4,720,000	21,901,000	38,417,000
Interest on Notes	1,550,295	1,469,000	6,372,000	12,555,000	10,500,000	8,000,000
Total	$ 28,781,776	$ 137,650,000	$ 32,831,000	$ 17,275,000	$ 32,401,000	$ 46,417,000
Balance	$ 197,006,365	$ 265,067,000	$ 240,295,000	$ 228,525,000	$ 223,752,000	$ 220,237,000
Contributions in Lieu of Taxes and Other	197,006,365	265,067,000	240,295,000	228,525,000	223,752,000	220,237,000
Balance	$ -	$ -	$ -	$ -	$ -	$ -

1. From Series XX, ZZ, CCC & DDD

Amended

APPENDIX III
DETAIL OF OPERATING and MAINTENANCE EXPENSES

	Actual[1]	Forecast				
	2011	2012	2013	2014	2015	2016
OPERATION						
Thermal and Gas Production						
Fuel Expense						
Fuel[2]	$ 2,291,386,000	$ 2,802,337,000	$ 2,472,915,000	$ 2,281,957,000	$ 2,187,275,000	$ 2,136,881,000
Purchased Power	660,872,000	672,026,000	802,042,000	879,509,000	999,854,000	1,083,858,000
Other Production Costs	65,268,000	58,168,680	52,100,960	47,731,360	44,906,440	43,522,000
Hydroelectric Plant Production	2,183,000	2,582,320	2,479,040	2,404,640	2,356,560	2,333,000
Transmission	20,130,000	25,285,350	24,207,600	23,431,800	22,930,050	22,684,050
Distribution	156,239,000	143,283,650	137,176,400	132,780,200	129,935,950	128,543,950
Client Accounting and Collection	114,837,000	112,837,000	110,995,000	109,668,000	108,811,000	108,390,000
Administrative and General	173,502,000	157,708,000	144,080,000	134,269,000	127,924,000	124,814,000
Interest Charge	-	-	-	-	-	-
Total Operation	$ 3,484,417,000	$ 3,974,228,000	$ 3,745,996,000	$ 3,611,751,000	$ 3,623,993,000	$ 3,651,026,000
MAINTENANCE						
Thermal and Gas Production	$ 104,710,000	$ 104,710,000	$ 104,710,000	$ 104,710,000	$ 104,710,000	$ 104,710,000
Hydroelectric Plant	3,022,000	3,022,000	3,022,000	3,022,000	3,022,000	3,022,000
Transmission	30,964,000	30,964,000	30,964,000	30,964,000	30,964,000	30,964,000
Distribution	74,762,000	74,762,000	74,762,000	74,762,000	74,762,000	74,762,000
General Plant	7,317,000	7,317,000	7,317,000	7,317,000	7,317,000	7,317,000
Total Maintenance	$ 220,775,000	$ 220,775,000	$ 220,775,000	$ 220,775,000	$ 220,775,000	$ 220,775,000
TOTAL O & M	$ 3,705,192,000	$ 4,195,003,000	$ 3,966,771,000	$ 3,832,526,000	$ 3,844,768,000	$ 3,871,801,000

1. Audited
2. Projections excludes interest, transportation and handling charges

Amended

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

	Actual[1]	Forecast					
	2011	2012	2013	2014	2015	2016
AGUIRRE STEAM PLANT						
Net MWh-Generated	4,501,504	4,776,000	4,090,000	3,609,000	3,956,000	3,603,000
Barrels of Fuel Oil Used	7,353,244	7,596,000	6,584,000	5,839,000	6,426,000	5,858,000
MBTUx1000	46,325	47,853	41,479	36,786	40,476	36,905
kWh Per Barrel	612	629	621	618	616	615
Cost of Fuel	$ 702,301,170	$ 887,737,000	$ 776,795,000	$ 683,149,000	$ 745,624,000	$ 673,336,000
Cost of Fuel Per Barrel	$ 95.51	$ 116.87	$ 117.98	$ 117.00	$ 116.03	$ 114.94
$/Mbtu	$ 15.16	$ 18.55	$ 18.73	$ 18.57	$ 18.42	$ 18.25
COSTA SUR STEAM PLANT						
Net MWh-Generated	3,505,827	3,592,000	4,027,000	4,346,000	3,661,000	4,220,000
Barrels of Fuel Oil Used	5,981,619	6,129,000	7,143,000	7,740,000	6,539,000	7,536,000
MBTUx1000	37,684	38,419	42,936	46,095	38,867	44,756
kWh Per Barrel	586	586	564	561	560	560
Cost of Fuel	$ 553,033,210	$ 688,495,000	$ 645,908,000	$ 619,483,000	$ 518,053,000	$ 594,292,000
Cost of Fuel Per Barrel	$ 92.46	$ 112.33	$ 90.43	$ 80.04	$ 79.23	$ 78.86
$/Mbtu	$ 14.68	$ 17.92	$ 15.04	$ 13.44	$ 13.33	$ 13.28
PALO SECO STEAM PLANT						
Net MWh-Generated	3,072,291	2,508,000	2,496,000	2,087,000	2,288,000	2,370,000
Barrels of Fuel Oil Used	5,153,974	4,146,000	4,134,000	3,466,000	3,790,000	3,910,000
MBTUx1000	32,470	26,118	26,028	21,832	21,825	24,634
kWh Per Barrel	596	605	604	602	604	606
Cost of Fuel	$ 483,153,086	$ 483,168,000	$ 487,718,000	$ 405,130,000	$ 437,103,000	$ 448,222,000
Cost of Fuel Per Barrel	$ 93.74	$ 116.54	$ 117.98	$ 116.89	$ 115.33	$ 114.63
$/Mbtu	$ 14.88	$ 18.50	$ 18.74	$ 18.56	$ 20.03	$ 18.20
SAN JUAN STEAM PLANT	*2,940,545*					
Net MWh-Generated	1,632,257	960,000	977,000	1,172,000	665,000	911,000
Barrels of Fuel Oil Used	2,891,435	1,735,000	1,768,000	2,117,000	1,204,000	1,649,000
MBTUx1000	18,216	10,929	11,136	13,339	7,587	10,390
kWh Per Barrel	565	553	553	554	552	552
Cost of Fuel	$ 274,958,041	$ 202,280,000	$ 207,914,000	$ 245,334,000	$ 140,795,000	$ 188,612,000
Cost of Fuel Per Barrel	$ 95.09	$ 116.59	$ 117.60	$ 115.89	$ 116.94	$ 114.38
$/Mbtu	$ 15.09	$ 18.51	$ 18.67	$ 18.39	$ 18.56	$ 18.15
AGUIRRE COMBINED-CYCLE UNITS						
Net MWh-Generated	192,467	160,000	131,000	210,000	114,000	137,000
Barrels of Fuel Oil or Equivalent	363,683	286,000	232,000	373,000	204,000	246,000
MBTUx1000	2,291	1,662	1,348	2,163	1,183	1,429
kWh Per Barrel (or equivalent)	529	559	565	563	559	557
Cost of Fuel	$ 38,616,803	$ 38,191,000	$ 30,985,000	$ 48,801,000	$ 25,894,000	$ 30,834,000
Cost of Fuel Per Barrel	$ 106.18	$ 133.53	$ 133.56	$ 130.83	$ 126.93	$ 125.34
$/Mbtu	$ 16.86	$ 22.98	$ 22.99	$ 22.56	$ 21.89	$ 21.58
COMBUSTION-TURBINES & DIESELS						
Net MWh-Generated	100,006	1,000	1,000	6,000	1,000	1,000
Barrels of Fuel Oil Used	186,477	2,000	2,000	16,000	2,000	2,000
MBTUx1000	1,175	14	11	93	14	11
kWh Per Barrel	536	500	500	375	500	500
Cost of Fuel	$ 20,357,885	$ 339,000	$ 256,000	$ 2,077,000	$ 313,000	$ 231,000
Cost of Fuel Per Barrel	$ 109.17	$ 169.50	$ 128.00	$ 129.81	$ 156.50	$ 115.50
$/Mbtu	$ 17.33	$ 24.21	$ 23.27	$ 22.33	$ 22.36	$ 21.00
CAMBALACHE						
Net MWh-Generated	81,331	31,000	44,000	77,000	11,000	7,000
Barrels of Fuel Oil or Equivalent	168,368	67,000	93,000	168,000	24,000	14,000
MBTUx1000	1,061	390	542	976	138	82
kWh Per Barrel	483	463	473	458	458	500
Cost of Fuel[3]	$ 16,462,034	$ 8,558,000	$ 11,948,000	$ 21,170,000	$ 2,932,000	$ 1,716,000
Cost of Fuel Per Barrel	$ 97.77	$ 127.73	$ 128.47	$ 126.01	$ 122.17	$ 122.57
$/Mbtu	$ 15.52	$ 21.94	$ 22.04	$ 21.69	$ 21.25	$ 20.93
MAYAGUEZ TURBINES						
Net MWh-Generated	-	68,000	28,000	73,000	45,000	35,000
Barrels of Fuel Oil or Equivalent	-	114,000	48,000	122,000	76,000	60,000
MBTUx1000	-	663	277	711	444	60
kWh Per Barrel	-	596	583	598	592	583
Cost of Fuel	$ -	$ 15,789,000	$ 6,487,000	15,800,000	9,801,000	7,450,000
Cost of Fuel Per Barrel	$ -	$ 138.50	$ 135.15	$ 129.51	$ 128.96	$ 124.17
$/Mbtu	$ -	$ 23.81	$ 23.42	$ 22.22	$ 22.07	$ 124.17
REPOWERED SAN JUAN UNITS. 5 & 6						
Net MWh-Generated	1,308,288	2,026,000	1,629,000	1,344,000	1,708,000	1,092,000
Barrels of Fuel Oil or Equivalent	1,791,994	2,793,000	2,272,000	1,868,000	2,386,000	1,522,000
MBTUx1000	11,290	16,207	13,183	10,843	13,845	8,829
kWh Per Barrel	730	725	717	719	716	717
Cost of Fuel	$ 202,503,647	$ 375,665,000	$ 304,715,000	240,029,000	304,582,000	187,963,000
Cost of Fuel Per Barrel	$ 113.00	$ 134.50	$ 134.12	$ 128.50	$ 127.65	$ 123.50
$/Mbtu	$ 17.94	$ 23.18	$ 23.11	$ 22.14	$ 22.00	$ 21.29

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

Continued from previous page

TOTAL THERMAL						
Net MWh-Generated	14,393,971	14,123,000	13,422,000	12,926,000	12,448,000	12,375,000
Barrels of Fuel Oil	23,890,794	22,868,000	22,277,000	21,709,000	20,651,000	20,797,000
MBTUx1000	150,512	142,255	136,940	132,838	124,379	127,096
kWh Per Barrel	602	618	603	595	603	595
Fuel Cost	$ 2,291,385,876	$ 2,700,222,000	$ 2,472,727,000	$ 2,280,972,000	$ 2,185,098,000	$ 2,132,657,000
Fuel financing credit line interest	$ 3,099,549	$ 5,000,000	$ 7,353,540	$ 7,411,650	$ 8,461,050	$ 10,237,800
Fuel Cost incl credit line interest	$ 2,294,485,425	$ 2,705,222,000	$ 2,480,080,540	$ 2,288,383,650	$ 2,193,559,050	$ 2,142,894,800
Cost of Fuel Per Barrel	$ 95.91	$ 118.08	$ 111.00	$ 105.07	$ 105.81	$ 102.55
$/Mbtu	$ 15.22	$ 18.98	$ 18.06	$ 17.17	$ 17.57	$ 16.78
Fuel Cost/Barrel incl fuel financing	$ 96.04	$ 118.30	$ 111.33	$ 105.41	$ 106.22	$ 103.04
Cost/Mbtu incl fuel financing	$ 15.24	$ 19.02	$ 18.11	$ 17.23	$ 17.64	$ 16.86
PURCHASED POWER-ECOELECTRICA						
Net MWh-Generated	3,586,528	3,362,000	3,262,000	3,613,000	3,659,000	3,685,000
Cost	$ 377,264,135	$ 383,297,000	$ 399,549,000	$ 439,023,000	$ 457,160,000	$ 478,456,000
$/MWH	$ 105.19	$ 114.01	$ 122.49	$ 121.51	$ 124.94	$ 129.84
PURCHASED POWER-AES						
Net MWh-Generated	3,509,657	3,372,502	3,362,521	3,362,524	3,363,000	3,372,000
Cost	$ 283,607,434	$ 306,235,000	$ 308,354,000	$ 311,741,000	$ 317,633,000	$ 325,437,000
$/MWH	$ 80.81	$ 90.80	$ 91.70	$ 92.71	$ 94.45	$ 96.51
PURCHASED POWER						
Net MWh-Generated	7,096,185	6,734,502	6,624,521	6,975,524	7,022,000	7,057,000
Cost	$ 660,871,569	$ 689,532,000	$ 707,903,000	$ 750,764,000	$ 774,793,000	$ 803,893,000
$/MWH	$ 93.13	$ 102.39	$ 106.86	$ 107.63	$ 110.34	$ 113.91
RENEWABLE ENERGY SOURCES						
Solar						
Net MWh-Generated		4,000	222,000	345,000	538,000	662,000
Cost		$ 683,000	$ 41,247,000	$ 64,919,000	$ 101,618,000	$ 126,303,000
$/MWH		$ 170.75	$ 185.80	$ 188.17	$ 188.88	$ 190.79
Wind						
Net MWh-Generated		-	$ 311,000	$ 337,000	$ 359,000	$ 360,000
Cost		$ -	$ 46,647,000	$ 51,223,000	$ 55,149,000	$ 55,993,000
$/MWH		$ -	$ 149.99	$ 152.00	$ 153.62	$ 155.54
Waste to Energy						
Net MWh-Generated		-	$ -	$ -	$ 432,000	$ 657,000
Cost		$ -	$ -	$ -	$ 53,984,000	$ 83,182,000
$/MWH		$ -	$ -	$ -	$ 124.96	$ 126.61
Land Fill Gas						
Net MWh-Generated		-	$ 56,000	$ 112,000	$ 126,000	$ 126,000
Cost		$ -	$ 6,245,000	$ 12,603,000	$ 14,310,000	$ 14,487,000
$/MWH		$ -	$ 111.52	$ 112.53	$ 113.57	$ 114.98
Total Renewable Sources						
Net MWh-Generated		4,000	589,000	794,000	1,455,000	1,805,000
Cost		$ 683,000	94,139,000	128,745,000	225,061,000	279,965,000
$/MWH		$ 170.75	$ 159.83	$ 162.15	$ 154.68	$ 155.11
HYDROELECTRIC						
Net MWh-Generated	149,530	126,170	126,170	126,170	126,170	126,170
TOTAL (Including Hydro & PP)						
Net MWh-Generated	21,639,686	20,987,672	20,761,691	20,821,694	21,051,170	21,363,170
Cost	$ 2,952,257,445	$ 3,390,437,000	$ 3,274,769,000	$ 3,160,481,000	$ 3,184,952,000	$ 3,216,515,000

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

APPENDIX V
DEBT SERIVE 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
5/1/97	AA	26,750,000 [1]	319,985,410	448,850,000	140.27	573,065,000	179.09
5/1/97	BB (Refunding)	27,135,000 [2]	319,985,410	448,850,000	140.27	573,065,000	179.09
1/3/02	II	21,345,000 [3]	415,641,309	636,368,000	153.11	746,303,000	179.55
1/3/02	JJ (Refunding)	167,285,000 [4]	415,641,309	636,368,000	153.11	746,303,000	179.55
7/2/02	KK (Refunding)	358,550,000 [5]	415,923,000	627,086,000	150.77	746,303,000	179.43
7/2/02	LL	98,125,000	415,923,000	627,086,000	150.77	746,303,000	179.43
10/3/02	MM (Refunding)	63,365,000 [6]	415,918,000	630,219,000	151.52	746,303,000	179.44
8/19/03	NN	171,525,000 [7]	442,399,978	664,780,000	150.27	728,160,000	164.59
8/26/04	OO (Refunding)	123,805,000 [8]	442,395,314	635,751,000	143.71	711,111,000	160.74
8/26/04	PP (Refunding)	86,340,000 [9]	442,395,314	635,751,000	143.71	711,111,000	160.74
4/4/05	QQ (Refunding)	95,270,000	473,784,011	612,777,000	129.34	711,111,000	150.09
4/4/05	RR	236,265,000 [10]	473,784,011	612,777,000	129.34	711,111,000	150.09
4/4/05	SS (Refunding)	449,275,000 [11]	473,784,011	612,777,000	129.34	711,111,000	150.09
5/3/07	TT	643,530,000	455,022,444	698,001,000	153.40	723,100,000	158.92
5/3/07	UU	863,960,000 [12]	455,022,444	698,001,000	153.40	723,100,000	158.92
5/30/07	V V (Refunding)	557,410,000	455,022,444	698,001,000	153.40	723,100,000	158.92
6/26/08	W W	686,660,000 [13]	476,874,792	662,928,000	139.02	756,405,000	158.62
4/7/10	XX	822,210,000	520,073,371	722,064,000	138.84	794,200,000	152.71
4/29/10	YY (Refunding)	320,175,000	532,820,338	722,064,000	135.52	794,200,000	149.06
5/5/10	ZZ (Refunding)	631,160,000	528,945,786	740,862,000	140.06	794,200,000	150.15
5/5/10	AAA	363,075,000	528,945,786	740,862,000	140.06	794,200,000	150.15
5/26/10	BBB	76,800,000	549,321,366	740,862,000	134.87	794,200,000	144.58
5/26/10	CCC	316,920,000	549,321,366	740,862,000	134.87	794,200,000	144.58
10/14/10	DDD (Refunding)	218,225,000	549,316,970	739,106,000	134.55	856,100,000	155.85
12/29/10	EEE	355,730,000	563,367,710	708,449,000	125.75	856,100,000	151.96

APPENDIX V
DEBT SERIVE COVERAGE UNDER THE 1974 TRUST AGREEMENT

Continued from previous page

The total debt issued under the Trust Agreement is $17,132,028,431 which includes refunding totalling $7,852,178,473.
As of June 30, 2011, the outstanding debt under the 1974 Trust Agreement is $7,780,890,000.

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

1. $62,335,000 refunded by Series UU; $5,450,000 refunded by Series QQ, $269,615,000 refunded by Series SS, $12,220,000 refunded by Series ZZ and deducted from the original $464,840,000 Series AA issue.
2. $30,285,000 refunded by Series SS, $12,420,000 refunded by Series ZZ and deducted from the original $100,750,000 Series BB issue.
3. $493,960,000 refunded by Series UU and deducted from the original $515,305,000 Series II issue.
4. $690,000 refunded by Series ZZ and deducted from the original $205,065,000 Series JJ issue.
5. $7,765,000 refunded by Series SS, $19,000,000 refunded by Series ZZ and deducted from the original $401,785,000 Series KK issue.
6. $11,000,000 refunded by Series SS, $1,045,000 refunded by Series ZZ and deducted from the original $105,055,000 Series MM issue.
7. $288,590,000 refunded by Series VV; $57,190,000 refunded by Series UU and deducted from original amount $517,305,000 Series NN issue.
8. $3,535,000 refunded by Series ZZ and deducted from original amount $136,105,000 Series OO issue.
9. $235,000 refunded by Series ZZ and deducted from original amount $86,595,000 Series PP issue.
10. $273,255,000 refunded by Series VV and deducted from original amount $509,520,000 Series RR issue.
11. $9,190,000 refunded by Series ZZ and deducted from original amount $483,930,000 Series SS issue.
12. $1,885,000 refunded by Series ZZ, $434,190,000 refunded by Series AAA and deducted from original amount $1,300,035,000 Series UU issue.
13. $10,685,000 refunded by Series ZZ and deducted from original amount $697,345,000 Series WW issue.

Refunding and new debt for Series 2012A and 2012B are not shown

APPENDIX VI

CAPITAL EXPENDITURES

	Actual[1]	Forecasted				
	2011	2012	2013	2014	2015	2016
Production Plant	$ 151,042,704	$ 104,340,000	$ 121,200,000	$ 151,145,000	$ 150,748,000	$ 116,875,000
Transmission Plant	77,744,617	76,110,000	57,100,000	82,084,000	82,463,000	83,797,000
Distribution Plant	142,461,419	87,205,000	82,955,000	105,629,000	94,089,000	83,448,000
General Land and Buildings	3,633,688	18,750,000	18,720,000	15,580,000	11,270,000	8,630,000
General Equipment	37,852,913	36,275,000	17,735,000	24,940,000	24,800,000	20,525,000
Preliminary Surveys and Investigations	(1,260,041)	3,820,000	2,290,000	13,232,000	9,625,000	13,525,000
SUBTOTAL	$ 411,475,300	$ 326,500,000	$ 300,000,000	$ 392,610,000	$ 372,995,000	$ 326,800,000
Construction Costs in Previous Year Reimbursed in Current Year	211,243,526	342,561,176	294,285,351	294,285,351	294,285,351	294,285,351
Construction Costs in Current Year to be Reimbursed Next Year	(342,561,176)	(294,285,351)	(294,285,351)	(294,285,351)	(294,285,351)	(294,285,351)
TOTAL FUNDS REQUIRED	$ 280,157,650	$ 374,775,825	$ 300,000,000	$ 392,610,000	$ 372,995,000	$ 326,800,000

1. Actual expenditures are net of adjustments from previous years.

Amended

APPENDIX VII
SOURCES OF FUNDS FOR CAPITAL EXPENDITURES

	Actual[1]	Forecast				
	2011	2012	2013	2014	2015	2016
FUNDS FROM BOND ISSUES AND NOTES						
REVENUE BONDS[2]						
Balance in Fund Start of Fiscal Year	$ 150,326,288	$ 226,351,825	$ 147,331,035	$ 194,033,000	$ 33,894,000	$ 108,213,000
$355.7M Series "EEE" Dec '10	334,466,002	-	-	-	-	-
$630.0M Series "2012A" Apr '12		359,529,035	-		-	
$370.M Series "2013A" April '13	-		350,750,000	-	-	-
$340.0M Series "2015A" Mar '15					318,245,000	
$345.0M Series "2016A" Mar '16						322,050,000
Balance in Fund End of Fiscal Year	(226,351,825)	(147,331,035)	(194,033,000)	(33,894,000)	(108,213,000)	(31,071,000)
PAID FROM REVENUE BONDS	$ 258,440,465	$ 438,549,825	$ 304,048,035	$ 160,139,000	$ 243,926,000	$ 399,192,000
NOTES						
Notes Paid	(50,000,000)	(50,000,000)	-	-	(175,000,000)	(300,000,000)
Notes Issued-Regular Financing	50,749,888	-	-	175,000,000	300,000,000	200,000,000
PAID FROM NOTES	$ 749,888	$ (50,000,000)	$ -	$ 175,000,000	$ 125,000,000	$ (100,000,000)
FUNDS FROM OTHER SOURCES						
Transfers from General Fund (Net)[3]	$ 760,006	(58,867,000)	(69,817,035)	(8,298,000)	(38,787,000)	(15,248,000)
Interest earned on Construction Fund	810,640	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000
Capitalized Interest on Sinking Fund	16,471,476	39,093,000	59,769,000	59,769,000	36,856,000	36,856,000
Grants and other (Principally From FEMA)	2,925,175	-	-	-	-	-
PAID FROM OTHER SOURCES	$ 20,967,297	(13,774,000)	(4,048,035)	57,471,000	4,069,000	27,608,000
GRAND TOTAL	$ 280,157,650	$ 374,775,825	$ 300,000,000	$ 392,610,000	$ 372,995,000	$ 326,800,000

1. Audited
2. Net proceeds from past bond issues

Amended

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

	Actual	Forecast				
	2011	2012	2013	2014	2015	2016
STEAM-ELECTRIC UNITS						
Aguirre	900	-	-	-	-	-
Costa Sur	990	-	-		-	-
CS Unit's 3 & 4				-	-	-
Palo Seco	602					
San Juan	400	-	-	-	-	-
Total	2,892	-	-	-	-	-
COMBUSTION-TURBINE UNITS						
Aguirre	42	-	-	-	-	-
Cambalache	248	-	-	-	-	-
Costa Sur	42	-	-	-	-	-
Palo Seco	126	-	-	-	-	-
Other	168	-	-	-	-	-
Total	626	-	-	-	-	-
NEW POWER PLANT						
Repowering (San Juan Units No. 5 & 6)	440	-	-	-	-	-
New Mayaguez Combustion Turbines	220	-	-			
Non-System Sources						
Cogenerators (Net)	961	-	-	-	-	-
Small Power Producers	-	-	-	-	-	-
COMBINED-CYCLE UNITS						
Aguirre	592	-	-	-	-	-
DIESEL UNITS						
Culebra & Vieques	8	-	-	-	-	-
HYDROELECTRIC CAPACITY (Total)	100	-	-	-	-	-
EXISTING CAPACITY (End of Previous Fiscal Year)	5,839	5,839	5,839	5,839	5,839	5,839
CAPACITY INSTALLED	-	-	-	-	-	-
CAPACITY RETIRED	-	-	-	-	-	-
CUMULATIVE TOTAL CAPACITY (MW)	5,839	5,839	5,839	5,839	5,839	5,839
Less: PEAK LOAD (MW)*	3,406	3,365	3,381	3,410	3,454	3,497
RESERVE CAPACITY (MW)	2,433	2,474	2,458	2,429	2,385	2,342

* Peak load forecast from IAU Global Insight projection

APPENDIX IX
DEPRECIATION EXPENSE

	Actual[1]	Forecasted					
	2011	2012	2013	2014	2015	2016
DEPRECIATION						
Steam Production Plant	$ 75,930,845	$ 78,968,126	$ 82,126,709	$ 85,411,944	$ 88,828,390	$ 92,381,398
Gas-turbine Production Plant	69,528,500	72,309,684	75,201,940	78,210,170	81,338,548	84,591,974
Hydroelectric Production Plant	1,636,667	1,702,135	1,770,217	1,841,029	1,914,670	1,991,254
Transmission Plant	54,821,383	57,014,273	59,294,741	61,666,650	64,133,293	66,698,534
Distribution Plant	130,259,966	135,470,446	140,889,019	146,524,866	152,385,806	158,481,021
General Plant[2]	50,916,639	52,953,336	55,071,374	57,274,341	59,565,293	61,947,820
Total Depreciation Expense	$ 383,094,000	$ 398,418,000	$ 414,354,000	$ 430,929,000	$ 448,166,000	$ 466,092,001
Amortization of Leasehold Improvements,	(118,031)					
TOTAL APPROPRIATION	$ 382,975,969	$ 398,418,000	$ 414,354,000	$ 430,929,000	$ 448,166,000	$ 466,092,001

1. Audited
2. Includes clearing accounts

APPENDIX X
DETAILS OF CAPITAL IMPROVEMENT PROGRAM

Budget Item Number		Estimated Expenditures by Fiscal Year 2012	2013	2014	2015	2016
PRODUCTION PLANT						
	THERMAL PRODUCTION PLANT					
100	New Generation	$ -	$ -	$ 12,000,000	$ 12,000,000	$ -
110	Renewable Energy	4,000,000	-	-	-	-
150	Fuel Handling and Storage Infrastructure	300,000	7,300,000	37,725,000	36,248,000	16,590,000
160	Boiler Improvements	22,460,000	39,200,000	49,250,000	38,160,000	19,000,000
165	Improvements to Steam Turbines and Generators	9,400,000	13,500,000	11,000,000	7,875,000	12,900,000
170	Improvements to Balance of Steam Plant	14,140,000	35,900,000	-	3,000,000	7,500,000
173	Environmental Contamination Treatment and Removal	2,500,000	1,000,000	1,500,000	-	2,000,000
175	Pollution Control Projects	13,850,000	6,000,000	8,500,000	14,500,000	16,000,000
	Total Thermal Production Plant	$ 66,650,000	$ 102,900,000	$ 119,975,000	$ 111,783,000	$ 73,990,000
	HYDROELECTRIC PRODUCTION PLANT					
180	Improvements to Hydroelectric Plants	$ 1,000,000	$ -	$ -	$ 4,965,000	$ 7,000,000
	Total Hydroelectricic Production Plant	$ 1,000,000	$ -	$ -	$ 4,965,000	$ 7,000,000
	OTHER PRODUCTION PLANT					
185	Improvements to Combustion Turbines	$ 3,500,000	$ 2,800,000	$ 8,200,000	$ 3,000,000	$ -
187	Improvements to Balance of Simple Cycle Gas Turbines	400,000	-	2,770,000	3,700,000	3,700,000
190	Improvements to Combined Cycle Steam Turbines	1,250,000	-	700,000	6,000,000	13,085,000
195	Improvements to Combined Cycle Balance of Plant	12,600,000	3,500,000	9,500,000	800,000	800,000
196	Improvements to Combined Cycle Gas Turbines	14,000,000	10,000,000	10,000,000	15,500,000	15,000,000
198	Improvements to Combined Cycle Heat Recovery Boilers	-	-	-	2,000,000	2,300,000
199	Improvements to Other Production Plant	4,940,000	2,000,000	-	3,000,000	1,000,000
	Total Other Production Plant	$ 36,690,000	$ 18,300,000	$ 31,170,000	$ 34,000,000	$ 35,885,000
	TOTAL PRODUCTION PLANT	$ 104,340,000	$ 121,200,000	$ 151,145,000	$ 150,748,000	$ 116,875,000
TRANSMISSION PLANT						
205	New 230 kV Lines	$ 17,898,000	$ 14,800,000	$ 21,200,000	$ 23,200,000	$ 4,901,000
207	New 115 kV Lines	100,000	1,975,000	475,000	2,975,000	975,000
210	New 38 kV Lines	1,000,000	675,000	1,100,000	2,665,000	1,755,000
215	38 kV Underground System	6,610,000	50,000	1,975,000	1,975,000	5,575,000
225	230/115 kV Transmission Centers & Capacity Increase	-	-	-	-	975,000
230	115/38 kV Transmission Centers & Capacity Increase	15,077,000	7,950,000	10,425,000	6,700,000	5,400,000
235	New 230 kV Switchyards & Expansions	2,530,000	550,000	975,000	7,425,000	4,425,000
237	New 115 kV Switchyards & Expansions	3,360,000	5,550,000	4,375,000	1,450,000	3,450,000
242	New 38 kV Switchyards & Expansions	1,930,000	300,000	3,950,000	5,265,000	8,875,000
245	New 115kV Capacitor Banks	-	-	-	-	975,000
255	Energy Management System (SCADA)	3,100,000	975,000	370,000	-	-
267	115 kV Line Rehabilitation	2,000,000	6,060,000	12,425,000	4,200,000	23,425,000
275	38 kV Line Rehabilitation	15,375,000	11,760,000	14,834,000	15,628,000	15,581,000

APPENDIX X
DETAILS OF CAPITAL IMPROVEMENT PROGRAM

Budget Item Number		Estimated Expenditures by Fiscal Year 2012	2013	2014	2015	2016
TRANSMISSION PLANT (Cont'd.)						
280	Transmission Pole Replacement	$ 1,400,000	1,375,000	$ 1,500,000	$ 5,000,000	$ 1,500,000
285	Increasing Capacity of Breakers	1,000,000	475,000	975,000	975,000	975,000
288	Reconstruction of Grounding Mat	230,000	$ 5,000	255,000	255,000	255,000
292	Misc. Transmission Plant Improvements—Elec. System	4,000,000	4,000,000	6,500,000	4,000,000	4,000,000
294	Other Transmission Plant	500,000	600,000	750,000	750,000	755,000
	TOTAL TRANSMISSION PLANT	$ 76,110,000	$ 57,100,000	$ 82,084,000	$ 82,463,000	$ 83,797,000
DISTRIBUTION PLANT						
300	New Distribution Substations	$ 5,245,000	$ 5,675,000	$ 3,725,000	$ 4,450,000	$ 4,400,000
305	Increase Substation Capacity	2,000,000	1,775,000	975,000	475,000	975,000
310	Emergency Substations	-	-	-	-	-
315	New 13 kV Substation Feeders	7,560,000	6,682,000	7,679,000	5,879,000	5,324,000
316	4.16 kV - 8.32 kV Feeders	510,000	1,930,000	1,515,000	1,443,000	1,098,000
325	Distribution Tie Lines (4.16 to 13.2 kV)	200,000	-	-	-	-
330	Line Extension to Serve New Customers	625,000	570,000	1,300,000	1,325,000	900,000
335	Construction of Urban Underground Lines	1,300,000	1,170,000	1,406,000	1,456,000	1,550,000
340	Installation of New Service Drops	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000
360	Substation Rehabilitation	4,000,000	4,000,000	6,000,000	4,000,000	4,000,000
363	Substation Improvements	285,000	65,000	365,000	200,000	175,000
368	Commercial Service Drops Replacement	600,000	600,000	600,000	600,000	600,000
370	Improvements to the Distribution System	14,640,000	17,880,000	25,085,000	29,200,000	25,810,000
374	Improvements to 13 kV Distribution System	4,300,000	3,155,000	3,378,000	3,190,000	3,737,000
376	Ordinary Insulation Replacement	150,000		-	-	-
378	Improvements to and Extensions of Underground Lines	9,640,000	12,675,000	16,096,000	11,846,000	9,005,000
379	Improvements to 4.16 - 8.32 kV Underground System	5,400,000	5,400,000	4,725,000	5,625,000	4,734,000
382	Street Lighting	2,860,000	3,000,000	8,000,000	8,000,000	5,000,000
383	Purchase of Line Transformers	1,200,000	1,150,000	1,240,000	1,640,000	1,440,000
385	Purchase of Meters	21,700,000	11,588,000	15,405,000	5,405,000	5,405,000
390	Purchase and Install Breakers, Sectionalizers, & Reclosers	1,600,000	1,050,000	1,550,000	1,550,000	1,550,000
392	Purchase and Install Voltage Regulators	-	275,000	275,000	495,000	495,000
395	Purchase and Install Distribution Line Capacitors	250,000	475,000	475,000	475,000	475,000
397	Line Voltage Converter	600,000	575,000	635,000	635,000	575,000
398	Distribution Automated Systems	-	1,000,000	1,000,000	1,000,000	1,000,000
399	Other Distribution Projects	1,340,000	1,065,000	3,000,000	4,000,000	4,000,000
	TOTAL DISTRIBUTION PLANT	$ 87,205,000	$ 82,955,000	$ 105,629,000	$ 94,089,000	$ 83,448,000

APPENDIX X
DETAILS OF CAPITAL IMPROVEMENT PROGRAM

Budget Item Number		Estimated Expenditures by Fiscal Year 2012	2013	2014	2015	2016
GENERAL PLANT						
	GENERAL LAND AND BUILDINGS					
400	Land and Rights-of-Way	$ 4,900,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000
410	Construction of New Warehouses	-	950,000	3,650,000	-	-
430	Construction of New Technical Offices	500,000	4,660,000	4,685,000	3,725,000	975,000
462	Minor Improvements to Technical Offices	850,000	700,000	850,000	775,000	775,000
464	Improvements to Technical Offices	-	-	975,000	-	-
468	Improvements to Warehouses	360,000	970,000	200,000	725,000	1,025,000
470	Improvements to Workshops	600,000	400,000	460,000	850,000	450,000
472	Improvements to Other Buildings	300,000	-	-	275,000	475,000
476	Improvements to Other Buildings & Grounds-Elect. System	3,120,000	-	-	-	-
478	Improvements to Buildings & Grounds--Admin. Serv.	6,860,000	6,950,000	500,000	660,000	670,000
480	Improvements to Buildings & Grounds--Cust. Serv. Offices	1,260,000	1,090,000	1,260,000	1,260,000	1,260,000
	TOTAL GENERAL LAND AND BUILDINGS	$ 18,750,000	$ 18,720,000	$ 15,580,000	$ 11,270,000	$ 8,630,000
	EQUIPMENT					
	OFFICE EQUIPMENT					
509	Finance	$ 20,000	$ 20,000	$ 25,000	$ 25,000	$ 25,000
513	Client Service	100,000	300,000	100,000	100,000	100,000
514	Transmission & Distribution	100,000	200,000	320,000	250,000	250,000
	Total Office Equipment	$ 220,000	$ 520,000	$ 445,000	$ 375,000	$ 375,000
	COMPUTER EQUIPMENT					
520	Executive Offices	$ -	$ 125,000	$ -	$ -	$ -
521	Information Systems	2,620,000	2,400,000	3,600,000	3,600,000	4,000,000
522	Legal	20,000	20,000	25,000	20,000	25,000
523	Planning & Environmental	225,000	220,000	300,000	225,000	170,000
525	Finance	200,000	180,000	175,000	205,000	205,000
526	Administrative Services	50,000	25,000	80,000	95,000	100,000
527	Human Resources	400,000	250,000	150,000	90,000	90,000
528	Electric System	-	200,000	200,000	-	-
529	Client Service	20,020,000	3,370,000	820,000	820,000	820,000
530	Transmission & Distribution	10,000	685,000	2,000,000	3,690,000	600,000
	Total Computer Equipment	$ 23,545,000	$ 7,475,000	$ 7,350,000	$ 8,745,000	$ 6,010,000
	TRANSPORTATION EQUIPMENT					
540	Air Transportation Equipment	$ 2,000,000	$ 300,000	$ 300,000	$ 300,000	$ 350,000
545	Land Transportation Equipment	6,415,000	5,000,000	8,000,000	6,000,000	6,100,000
	Total Transportation Equipment	$ 8,415,000	$ 5,300,000	$ 8,300,000	$ 6,300,000	$ 6,450,000

APPENDIX X
DETAILS OF CAPITAL IMPROVEMENT PROGRAM

Budget Item Number		Estimated Expenditures by Fiscal Year 2012	2013	2014	2015	2016
GENERAL PLANT (Cont'd)						
	COMMUNICATIONS EQUIPMENT					
550	Communications Equipment-Electric System	$ -	$ -	$ 1,000,000	$ 1,000,000	$ 1,000,000
551	Communications Equipment-Client Services	180,000	200,000	260,000	260,000	260,000
553	Communications Equipment-T&D	220,000	75,000	75,000	75,000	75,000
555	Telephone and Data lines	-	-	1,500,000	1,500,000	1,500,000
	Total Communication Equipment	$ 400,000	$ 275,000	$ 2,835,000	$ 2,835,000	$ 2,835,000
	OTHER EQUIPMENT					
560	Planning and Environmental	$ 545,000	$ 725,000	$ 1,900,000	$ 1,080,000	$ 900,000
562	Engineering	550,000	550,000	725,000	725,000	725,000
564	Administrative Services	470,000	480,000	310,000	430,000	335,000
565	Transportation Workshop	100,000	175,000	275,000	190,000	275,000
566	Human Resources	10,000	10,000	10,000	10,000	10,000
568	Electric System	-	-	500,000	2,000,000	500,000
570	Client Services	310,000	715,000	355,000	355,000	355,000
572	Transmission and Distribution	1,410,000	1,210,000	1,435,000	1,255,000	1,255,000
576	Purchase Other Equipment - Corporate Security	300,000	300,000	500,000	500,000	500,000
	Total Other Equipment	$ 3,695,000	$ 4,165,000	$ 6,010,000	$ 6,545,000	$ 4,855,000
	TOTAL EQUIPMENT	$ 36,275,000	$ 17,735,000	$ 24,940,000	$ 24,800,000	$ 20,525,000
TOTAL GENERAL PLANT		$ 55,025,000	$ 36,455,000	$ 40,520,000	$ 36,070,000	$ 29,155,000
PRELIMIN. SURVEYS & INVESTIGATIONS						
600	Engineering	$ 3,000,000	$ 1,500,000	$ 1,975,000	$ 2,975,000	$ 2,975,000
605	Administrative Services	$ 200,000	$ 100,000	$ 150,000	$ 250,000	$ 250,000
610	Planning and Environmental	180,000	540,000	8,700,000	6,200,000	10,100,000
611	Renewable Energy Sources	440,000	150,000	2,407,000	200,000	200,000
	TOTAL PRELIMIN. SURVEYS & INVESTIGATIONS	$ 3,820,000	$ 2,290,000	$ 13,232,000	$ 9,625,000	$ 13,525,000
NET CAPITAL IMPROVEMENT PROGRAM		$ 326,500,000	$ 300,000,000	$ 392,610,000	$ 372,995,000	$ 326,800,000