KPMG

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Financial Statements and
Required Supplementary Information

June 30, 2012 and 2011

(With Independent Auditors' Report Thereon)

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

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KPMG LLP
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Independent Auditors' Report

The Board of Water and Power Commissioners
Department of Water and Power
City of Los Angeles:

We have audited the accompanying financial statements of the City of Los Angeles' Department of Water and Power's Power Revenue Fund (Power System), an enterprise fund of the City of Los Angeles, California, as of June 30, 2012 and 2011, as listed in the table of contents. These financial statements are the responsibility of the Los Angeles Department of Water and Power's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America; the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Power System's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in note 1 to the financial statements, the financial statements of the Power System are intended to present the financial position, the changes in financial position and cash flows of only that portion of the business-type activities of the City of Los Angeles, California that are attributable to the transactions of the Power System. They do not purport to, and do not, present fairly the financial position of the City of Los Angeles, California as of June 30, 2012 and 2011, the changes in its financial position or, where applicable, its cash flows for the years then ended, in conformity with U.S. generally accepted accounting principles.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Power System as of June 30, 2012 and 2011, and changes in its financial position and its cash flows for the years then ended, in conformity with U.S. generally accepted accounting principles.

In accordance with *Government Auditing Standards*, we have also issued our report dated November 30, 2012, on our consideration of the Power System's internal control over financial reporting and our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of those reports is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* and should be considered in assessing the results of our audits.

U.S. generally accepted accounting principles require that the management's discussion and analysis and the required supplementary information on pages 3-12 and 70 be presented to supplement the basic financial statements. Such information, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic financial statements, and other knowledge we obtained during our audit of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

KPMG LLP

November 30, 2012

The following discussion and analysis of the financial performance of the City of Los Angeles' (the City) Department of Water and Power's (the Department) Power Revenue Fund (the Power System) provides an overview of the financial activities for the fiscal years ended June 30, 2012 and 2011. Descriptions and other details pertaining to the Power System are included in the notes to the financial statements. This discussion and analysis should be read in conjunction with the Power System's financial statements, which begin on page 13.

Using This Financial Report

This annual financial report consists of the Power System's financial statements and required supplementary information and reflects the self-supporting activities of the Power System that are funded primarily through the sale of energy, transmission, and distribution services to the public it serves.

Balance Sheets, Statements of Revenues, Expenses, and Changes in Fund Net Assets, and Statements of Cash Flows

The financial statements provide an indication of the Power System's financial health. The balance sheets include all of the Power System's assets, deferred outflows, and liabilities, using the accrual basis of accounting, as well as an indication about which assets can be utilized for general purposes, and which net assets are restricted as a result of bond covenants and other commitments. The statements of revenues, expenses, and changes in fund net assets report all of the revenues and expenses during the time periods indicated. The statements of cash flows report the cash provided by and used in operating activities, as well as other cash sources and uses, such as investment income and cash payments for bond principal and capital additions and betterments.

The following table summarizes the financial condition and changes in fund net assets of the Power System as of and for the fiscal years ended June 30, 2012, 2011, and 2010:

Table 1 – Condensed Schedule of Assets, Liabilities, and Fund Net Assets

(Amounts in millions)

		As of June 30	
Assets	**2012**	**2011**	**2010**
Utility plant, net	$ 8,114	7,431	6,979
Restricted investments	639	634	683
Other noncurrent assets	2,100	2,534	2,364
Current assets	1,684	1,847	1,623
Deferred outflows on derivative instruments	91	74	84
	$ 12,628	12,520	11,733
Liabilities and Fund Net Assets			
Long-term debt, net of current portion	$ 6,354	6,498	5,711
Other long-term liabilities	302	248	355
Current liabilities	917	838	788
	7,573	7,584	6,854
Fund net assets:			
Invested in capital assets, net of related debt	1,533	1,307	1,387
Restricted	1,525	1,417	1,507
Unrestricted	1,997	2,212	1,985
Total fund net assets	5,055	4,936	4,879
	$ 12,628	12,520	11,733

Note: Certain prior year amounts have been reclassified to conform to the current year's presentation.

Table 2 – Condensed Schedule of Revenues, Expenses, and Changes in Fund Net Assets

(Amounts in millions)

	Year ended June 30		
	2012	**2011**	**2010**
Operating revenues:			
Residential	$ 977	966	1,015
Commercial and industrial	2,040	2,047	2,062
Sales for resale	36	84	126
Other	29	29	32
Total operating revenues	3,082	3,126	3,235
Operating expenses:			
Fuel for generation and purchased power	(1,313)	(1,290)	(1,310)
Maintenance and other operating expenses	(1,317)	(1,405)	(1,315)
Total operating expenses	(2,630)	(2,695)	(2,625)
Operating income	452	431	610
Nonoperating revenues (expenses):			
Investment income	78	82	106
Federal bond subsidies	35	28	—
Other nonoperating revenues and expenses, net	14	12	25
Debt expenses	(237)	(265)	(212)
Total nonoperating expenses	(110)	(143)	(81)
Income before capital contributions and transfers	342	288	529
Capital contributions	27	28	13
Transfers to the reserve fund of the City of Los Angeles	(250)	(259)	(220)
Increase in fund net assets	119	57	322
Beginning balance of fund net assets	4,936	4,879	4,557
Ending balance of fund net assets	$ 5,055	4,936	4,879

Assets

Utility Plant

During fiscal years 2012 and 2011, the Power System capitalized $503 million and $557 million of additions, respectively, including transfers from construction work in progress to utility plant in service. Of the

(Continued)

$503 million, $294 million, or 59% is related to distribution plant assets and mostly attributable to our Power Reliability Program (PRP) to improve distribution system reliability including replacement of aging poles, crossarms, cables, station equipment, and transformers. Other distribution system additions included construction of new business line facilities and installation of meters related to the Automatic Meter Infrastructure (AMI). In addition, $128 million or 26% is mostly related to generation plant assets including improvements to generator units at in-basin stations and construction of Adelanto Photovoltaic System. In addition, $57 million, or 11% is related to general plant assets including purchases of transportation equipment, improvements to general facilities, and installation of fiber optics. Of the $557 million during fiscal year 2011, $356 million, or 64% was related to distribution plant assets and mostly attributable to our Power Reliability Program (PRP), installation of new business line facilities, and meters. In addition, $90 million or 16% is mostly related to generation plant assets including station improvements at the in-basin generating stations. In addition, $88 million, or 16% is related to general plant assets including a new joint service center, communication/mainframe hardware equipment, and general office building improvements.

Construction work in progress increased by $526 million in fiscal year 2012 and increased by $254 million in fiscal year 2011. The 2012 increases are mostly attributable to generation system assets including repowering of Haynes generating station units 5 & 6, construction of Pine Tree Photovoltaic System, and improvements at in-basin generating stations. In addition, general plant increases is attributable to the Customer Information System (CIS) replacement. The 2011 increases were attributable to similar projects.

Additional information regarding the Power System's utility plant assets can be found in note 4 to the accompanying financial statements.

The tables that follow summarize the generating resources available to the Department as of June 30, 2012. These resources include those owned by the Department (either solely or jointly with other utilities) as well as resources available through long-term purchase agreements. Generating station capacity is measured in megawatts (MWs).

Table 3 – Department-Owned Generation Facilities

Type of fuel	Notional amount (Number of facilities)	Number of units	Net maximum capability (MWs)	Net dependable capability (MWs)
Natural gas	4 [1]	22	3,399	3,313
Large hydro	1	7 [2]	1,247	1,175
Renewables	37	206 [3]	444 [4]	222
Subtotal	42	235	5,090	4,710
CDWR	—	—	(120) [5]	(56)
Total	42	235	4,970	4,654

(1) Consists of the following generating stations: Harbor Station, Haynes Station, Scattergood Station, and Valley Station.

(2) The Castaic Plant currently has six (1,075 MWs) out of seven units available due to ongoing modernization work scheduled to be completed by 2014.

(3) The Department-owned renewable resources in-service include the Los Angeles Aqueduct, Owens Valley, and Owens Gorge small hydro units that qualify under the Department's renewable resource definition. Also included are microturbine units at the Lopez Canyon Landfill and Department built photovoltaic solar installations, the Pine Tree Wind Project, Linden Wind Farm, and a local small hydro plant. Not included in the counts are the units that were upgraded at the Castaic Plant. Also not included are the two Scattergood gas-fueled units that partially burn digester gas in which the output related to the digester gas also qualifies under the Department's renewable resource definition.

(4) Included are the 30 MWs of qualify renewable capacity addition at the Castaic Plant. Also included are the 16 MWs of renewable energy generated at the Scattergood Station by burning digester gas from the Hyperion Treatment Plant.

(5) Energy payable to the California Department of Water Resources (CDWR) for energy generated at the Castaic Plant. This amount varies weekly up to maximum of 120 MWs.

Table 4 – Jointly Owned and Contracted Facilities

Type	Number of facilities	Net maximum capability (MWs)	Net dependable capability (MWs)
Large hydro	1	491 (1)	468
Nuclear	1	387 (2)	380
Coal	3	1,652 (3)	1,652
Renewables/DG	5,534 (4)	887	258
Total	5,539	3,417	2,758

(1) The Department's Hoover Plant contract entitlement is 25.16% of the Hoover total contingent capacity of 1,951 MWs. Current reduced lake level has reduced available capacity to about 468 MWs annual average.

(2) The Department's Palo Verde Station (PVNGS) entitlement is 9.66% of the maximum net plant capability of 4,003 MWs.

(3) The Department's current Intermountain Station (IPP) entitlement is 66.79% of the maximum net plant capability of 1,800 MWs. A portion of the IPP entitlement is subject to variable recall. The Department's Navajo Station entitlement is 21.20% of the maximum net plant capability of 2,250 MWs. The Mohave Station generating units were removed from service at the end of 2005.

(4) The Department's contracted renewable resources in-service include units at several landfill sites in the Los Angeles area; biogas fuel purchases outside of California; local hydro unit; wind farms in Wyoming, Oregon, Utah, and Washington; customer solar photovoltaic installations locally, and customer distributed generation (DG) units located in Los Angeles also provide energy resources.

Liabilities and Fund Net Assets

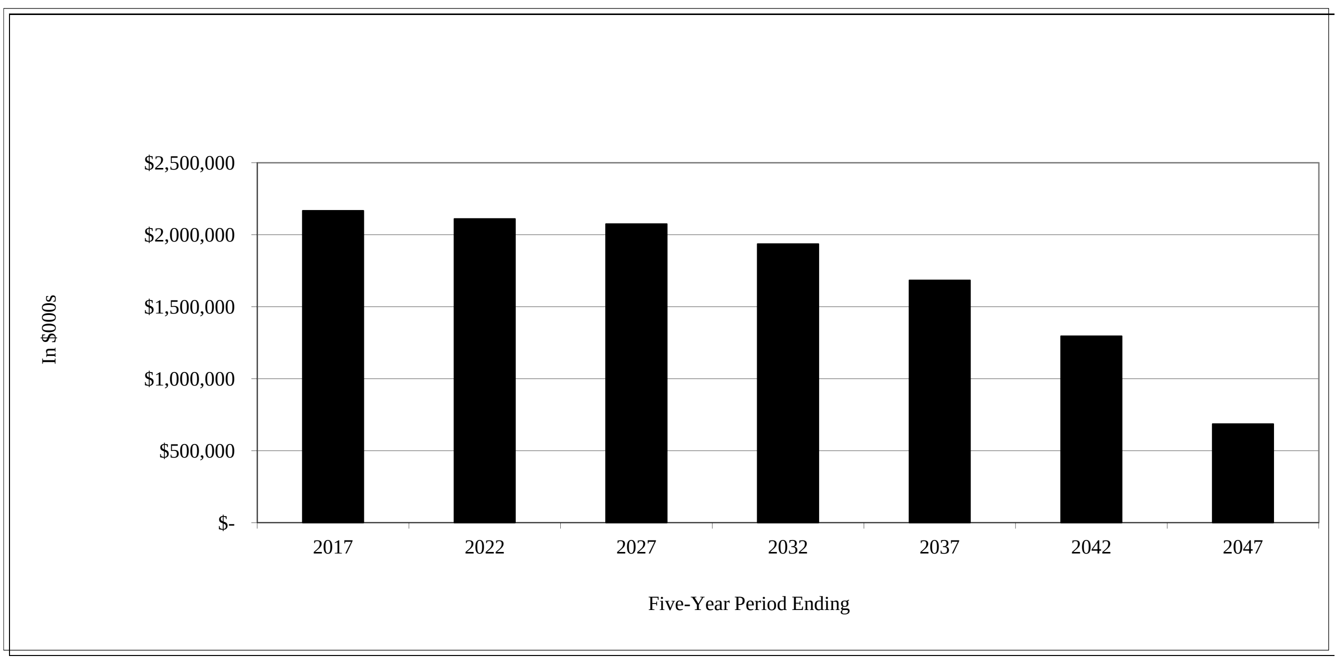
Long-Term Debt

As of June 30, 2012, the Power System's total outstanding long-term debt balance was approximately $6.601 billion. The decrease of $76 million over the prior year's balance resulted from the scheduled maturities of $62 million and $14 million amortized premiums, discounts, and debt-related costs (including net loss on refundings).

As of June 30, 2011, the Power System's total outstanding long-term debt balance was approximately $6.677 billion. The increase of $725 million over the prior year's balance resulted from the sale of $1.684 billion of the Power System revenue bonds less the refunding of $833 million revenue bonds and scheduled maturities of $126 million.

Outstanding principal, plus scheduled interest as of June 30, 2012, is scheduled to mature as shown in the chart below:

Chart: Debt Service Requirements



In addition, the Power System had $490.4 million and $485.6 million on deposit in trust funds restricted for the use of debt reduction as of June 30, 2012 and 2011, respectively.

In October 2012, Standard & Poor's Rating Services, Moody's Investors Service, and Fitch Ratings affirmed the Power System's bond rating of AA-, Aa3, and AA-, respectively, due to the Power System's broad revenue stream and a competitive power supply portfolio that has historically provided competitive retail electricity rates and evident strategic focus on positioning the utility to improve system reliability while meeting state mandated greenhouse emission rules and renewable energy standards. Additional information regarding the Power System's long-term debt can be found in note 10 to the financial statements.

Changes in Fund Net Assets

Operating Revenues

The operating revenues of the Power System are generated from wholesale and retail customers. There are four major customer categories of retail revenue. These categories include residential, commercial, industrial, and other, which includes public street lighting. Table 5 summarizes the percentage contribution of retail revenues from each customer segment in fiscal years 2012 and 2011:

Table 5 – Revenue and Percentage of Revenue by Customer Class

(Amounts in thousands)

	Fiscal year 2012		Fiscal year 2011	
	Revenue	**Percentage**	**Revenue**	**Percentage**
Type of customer:				
Residential	$ 976,820	32%	$ 966,436	32%
Commercial	1,803,794	59	1,785,452	59
Industrial	235,728	8	261,398	8
Other	29,202	1	28,409	1
	$ 3,045,544	100%	$ 3,041,695	100%

While commercial customers consume the most electricity, residential customers represent the largest customer class. As of June 30, 2012 and 2011, the Power System had approximately 1.5 million customers. As shown in Table 6, 1.3 million, or 87% and 86%, of total customers were in the residential customer class in fiscal years 2012 and 2011, respectively.

Table 6 – Number of Customers and Percentage of Customers by Customer Class

(Amounts in thousands)

	Fiscal year 2012		Fiscal year 2011	
	Number	**Percentage**	**Number**	**Percentage**
Type of customer:				
Residential	1,274	87%	1,263	86%
Commercial	183	12	184	13
Industrial	12	1	12	1
Other	2	—	2	—
	1,471	100%	1,461	100%

(Continued)

Fiscal Year 2012

Retail revenues remained stable and wholesale revenues decreased $48 million from fiscal year 2011. The decrease in whole revenue was mainly due to $38 million of whole revenue being designated as deferred revenue and transferred to the Rate Stabilization Account. Retail consumption of energy decreased 27 gigawatt hours, or less than 1% year over year while wholesale consumption decreased 271 gigawatt hours.

Fiscal Year 2011

Retail revenues decreased by $67 million and wholesale revenues decreased $42 million from fiscal year 2010. The decrease in revenue is mainly due to lower consumption despite a one-time increase of 0.6 cents/kWh in the Energy Cost Adjustment Factor effective July 1, 2010. Retail consumption of energy decreased 255 million KWhs year over year while wholesale consumption decreased 256,967 MWhs.

Operating Expenses

Fuel for generation and purchased power are two of the largest expenses that the Power System incurs each fiscal year. Fuel for generation expense includes the cost of fuel that is used to generate energy. The majority of fuel costs include the cost of natural gas, coal, and nuclear fuel.

Purchased power expense includes the cost of buying power on the open market and paying the current portion of the Power System's purchased power contracts. Under these purchase power contracts, the Department has an entitlement to the energy that is produced at various generating stations and an entitlement to the use of various transmission facilities. Most of these contracts require the Department to pay for these services regardless of whether the energy or transmission is used. These types of contracts are referred to as "take-or-pay" contracts.

Depreciation expense is computed using the straight-line method based on service lives for all projects completed after July 1, 1973, and for all office and shop structures, related furniture and equipment, and transportation and construction equipment. Depreciation for facilities completed prior to July 1, 1973 is computed using the 5% sinking fund method based on estimated service lives. The Department uses the composite method of depreciation and, therefore, groups assets into composite groups for purposes of calculating depreciation expense. Estimated service lives range from 5 to 75 years. Amortization expense for computer software is computed using the straight-line method over 5 years.

The table below summarizes the Power System's operating expenses during fiscal years 2012 and 2011:

Table 7 – Operating Expenses and Percentage of Expense by Type of Expense

(Amounts in thousands)

	Fiscal year 2012		Fiscal year 2011	
	Expense	**Percentage**	**Expense**	**Percentage**
Type of expense:				
Fuel for generation	$ 403,406	15%	$ 435,812	16%
Purchased power	909,910	35	853,745	32
Other operating expenses	617,456	23	699,588	26
Maintenance	304,750	12	319,043	12
Depreciation and amortization	394,019	15	386,937	14
	$ 2,629,541	100%	$ 2,695,125	100%

Fiscal Year 2012

Fiscal year 2012 operating expenses were $66 million lower as compared to fiscal year 2011, driven primarily by an $82 million decrease in other operating expenses. Fuel and Purchased Power expenses increased $24 million due to a year-over-year increase of $56 million in renewable generation expenditures.

The $82 million decrease in other operating expenses can be primarily attributed to a decrease of $70 million in the expensing of demand side management (energy efficiency) and solar incentive program expenditures. Demand side management and solar programs for customers are treated as regulatory assets and therefore, these expenditures are now capitalized and amortized over the expected useful life. Maintenance expenses decreased $14 million year over year, primarily due to lower transmission plant and steam plant maintenance costs. The $7.1 million increase in depreciation and amortization expense is primarily due to capital improvements in Steam Production plant, as well as additional amortization expense from the regulatory assets mentioned above.

Fiscal Year 2011

Fiscal year 2011 operating expenses were $69.8 million higher as compared to fiscal year 2010, driven primarily by a $49.1 million increase in depreciation expense. Fuel and Purchased Power expenses decreased $20.3 million due to lower retail sales and decreased wholesale generation activities despite a year-over-year increase of $114.2 million in renewable generation expenditures.

The $29.5 million increase in other operating costs can be primarily attributed to an increase of $18.8 million in overhead line and miscellaneous distribution expenses and a $10.4 million increase customer accounting and collection expenses. Maintenance expenses increased $11.6 million year over year, primarily due to higher transmission plant and distribution plant maintenance costs.

Nonoperating Revenues and Expenses

Fiscal Year 2012

The major nonoperating activities of the Power System for fiscal year 2012 included the transfer of $250 million to the City's General Fund, interest income earned on investments of $78 million, $35 million in federal bond subsidies, and $237 million in debt expenses.

The transfer to the City is based on 8% of the previous year's operating revenues. Operating revenues for fiscal year 2011 were $3.1 billion, which generated a city transfer of $250 million.

The $4 million decrease in interest income is due to declining market interest rates coupled with decreases in funds held in the related restricted investments.

The $7 million increase in federal bond subsidies is directly related to interest payment subsidies that are received from the U.S. Treasury.

The $7 million decrease in interest on debt is mainly due to the debt refinancing undertaken by the Power System during fiscal 2011.

Fiscal Year 2011

The major nonoperating activities of the Power System for fiscal year 2011 included the transfer of $259 million to the City's General Fund, interest income earned on investments of $82 million, $28 million in federal bond subsidies, and $265 million in debt expenses.

The transfer to the City is based on 8% of the previous year's operating revenues. Operating revenues for fiscal year 2010 were $3.2 billion, which generated a city transfer of $259 million.

The $25 million decrease in interest income is due to declining market interest rates coupled with decreases in funds held in the related restricted investments.

The $28 million increase in federal bond subsidies is directly related to interest payment subsidies that are received from the U.S. Treasury.

The increase in debt expense is mainly due to the interest expense related to the 2010 Series A, B, C, and D Bonds issued at end of fiscal year 2010 and during fiscal year 2011.

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Balance Sheets

June 30, 2012 and 2011

(Amounts in thousands)

Assets and Deferred Outflows		2012	2011
Noncurrent assets:			
Utility plant:			
Generation	$	4,318,819	4,192,467
Transmission		1,046,800	1,022,010
Distribution		6,338,353	6,045,053
General		1,318,063	1,271,714
		13,022,035	12,531,244
Accumulated depreciation		(6,462,915)	(6,086,691)
		6,559,120	6,444,553
Construction work in progress		1,211,851	685,485
Nuclear fuel, at amortized cost		49,687	44,328
Natural gas field, net		293,006	256,622
		8,113,664	7,430,988
Restricted investments		639,121	634,408
Cash and cash equivalents – restricted		20,730	552,704
Long-term notes and other receivables, net of current portion		838,755	903,055
Underrecovered costs		312,373	294,226
Deferred debits		296,223	179,162
Net pension asset		—	14,386
Net postretirement asset		631,479	590,686
Total noncurrent assets		10,852,345	10,599,615
Current assets:			
Cash and cash equivalents – unrestricted		417,895	561,414
Cash and cash equivalents – restricted		395,225	308,879
Cash collateral received from securities lending transactions		—	69,534
Customer and other accounts receivable, net of $20,000 allowance for losses		352,856	340,518
Current portion of long-term notes receivable		65,593	102,307
Due from Water System		—	3,267
Accrued unbilled revenue		173,233	156,079
Materials and fuel		169,839	154,490
Prepayments and other current assets		109,293	150,265
Total current assets		1,683,934	1,846,753
Total assets		12,536,279	12,446,368
Deferred outflows on derivative instruments		91,296	73,770
Total assets and deferred outflows	$	12,627,575	12,520,138

(Continued)

LOS ANGELES DEPARTMENT OF WATER AND POWER
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Balance Sheets

June 30, 2012 and 2011

(Amounts in thousands)

Fund Net Assets and Liabilities	**2012**	**2011**
Fund net assets:		
Invested in capital assets, net of related debt	$ 1,533,344	1,307,325
Restricted:		
Debt service	620,688	549,511
Capital projects	123,627	120,008
Other postemployment benefits	631,479	590,686
Pension benefits	—	14,386
Other purposes	148,949	142,684
Unrestricted	1,996,651	2,211,952
Total fund net assets	5,054,738	4,936,552
Long-term debt, net of current portion	6,354,469	6,497,714
Other noncurrent liabilities:		
Accrued liabilities	8,767	10,487
Deferred credits	139,876	123,160
Accrued workers' compensation claims	43,475	40,300
Derivative instrument liabilities	91,296	73,770
Net pension liability	18,209	—
Total other noncurrent liabilities	301,623	247,717
Current liabilities:		
Current portion of long-term debt	246,582	178,885
Accounts payable and accrued expenses	341,942	266,692
Accrued interest	139,872	129,874
Accrued employee expenses	102,271	97,340
Deferred credits	21,100	95,830
Due to Water Services	64,978	—
Obligations under securities lending transactions	—	69,534
Total current liabilities	916,745	838,155
Total liabilities	7,572,837	7,583,586
Total liabilities and fund net assets	$ 12,627,575	12,520,138

See accompanying notes to financial statements.

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Statements of Revenues, Expenses, and Changes in Fund Net Assets

Years ended June 30, 2012 and 2011

(Amounts in thousands)

		2012	2011
Operating revenues:			
Residential	$	976,820	966,436
Commercial and industrial		2,039,522	2,046,850
Sales for resale		36,136	84,262
Other		53,036	55,901
Uncollectible accounts		(23,834)	(27,492)
		3,081,680	3,125,957
Operating expenses:			
Fuel for generation		403,406	435,812
Purchased power		909,910	853,745
Maintenance and other operating expenses		922,206	1,018,631
Depreciation and amortization		394,019	386,937
		2,629,541	2,695,125
Operating income		452,139	430,832
Nonoperating revenues (expenses):			
Investment income		77,747	81,847
Federal bond subsidies		35,143	28,069
Other nonoperating income		17,571	16,999
		130,461	126,915
Other nonoperating expenses		(3,380)	(4,183)
		127,081	122,732
Debt expenses:			
Interest on debt		269,875	276,897
Allowance for funds used during construction		(32,187)	(11,806)
		237,688	265,091
Income before capital contributions and transfers		341,532	288,473
Capital contributions		26,731	27,983
Transfers to the reserve fund of the City of Los Angeles		(250,077)	(258,815)
Increase in fund net assets		118,186	57,641
Fund net assets:			
Beginning of period		4,936,552	4,878,911
End of period	$	5,054,738	4,936,552

See accompanying notes to financial statements.

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Statements of Cash Flows

Direct Method

Years ended June 30, 2012 and 2011

(Amounts in thousands)

		2012	2011
Cash flows from operating activities:			
Cash receipts:			
Cash receipts from retail customers	$	3,010,267	3,021,564
Cash receipts from retail customers for other agency services		593,026	615,957
Cash receipts from interfund services provided		476,406	448,390
Cash disbursements:			
Cash payments to employees		(547,522)	(512,045)
Cash payments to suppliers		(1,471,947)	(1,642,853)
Cash payments for interfund services used		(572,341)	(571,847)
Cash payments to other agencies for fees collected		(591,684)	(585,948)
Other operating cash payments		(44,595)	(106,739)
Net cash provided by operating activities		851,610	666,479
Cash flows from noncapital financing activities:			
Payments to the reserve fund of the City of Los Angeles		(250,077)	(258,815)
Interest paid on noncapital revenue bonds		—	(1,044)
Net cash used in noncapital financing activities		(250,077)	(259,859)
Cash flows from capital and related financing activities:			
Additions to plant and equipment, net		(1,093,491)	(857,112)
Capital contributions		25,167	32,129
Principal payments and maturities on long-term debt		(62,157)	(173,820)
Proceeds from issuance of bonds and revenue certificates		—	898,975
Debt interest payments		(270,937)	(248,214)
Federal bond subsidies		35,143	28,069
Net cash used in capital and related financing activities		(1,366,275)	(319,973)
Cash flows from investing activities:			
Purchases of investment securities		(1,224,872)	(1,680,327)
Sales and maturities of investment securities		1,220,159	1,728,579
Proceeds from notes receivable		64,300	78,191
Investment income		116,008	86,199
Net cash provided by investing activities		175,595	212,642
Net (decrease) increase in cash and cash equivalents		(589,147)	299,289
Cash and cash equivalents:			
Cash and cash equivalents at July 1 (including $861,583 and $699,853 reported in restricted accounts, respectively)		1,422,997	1,123,708
Cash and cash equivalents at June 30 (including $415,955 and $861,583 reported in restricted accounts, respectively)	$	833,850	1,422,997

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Statements of Cash Flows

Indirect Method

Years ended June 30, 2012 and 2011

(Amounts in thousands)

		2012	2011
Reconciliation of operating income to net cash provided by operating activities:			
Operating income	$	452,139	430,832
Adjustments to reconcile operating income to net cash provided by operating activities:			
Depreciation and amortization		394,019	386,937
Depletion expense		29,064	14,398
Amortization of nuclear fuel		13,248	11,974
Provision for losses on customer and other accounts receivable		23,834	27,492
Changes in assets and liabilities:			
Customer and other accounts receivable		(36,155)	(25,331)
Accrued unbilled revenue		(17,154)	2,758
Underrecovered costs		(18,147)	(43,846)
Materials and fuel		(15,349)	3,513
Deferred debits		(117,061)	(19,162)
Due from Water System		3,267	4,009
Net pension asset		14,386	38,944
Accounts payable and accrued expenses		81,921	23,916
Accrued liabilities		—	(1,553)
Deferred credits		(58,014)	(92,802)
Due to Water Services		64,978	—
Net pension liability		18,209	—
Net other postemployment benefit liability		(40,793)	(57,213)
Prepayments and other		59,218	(38,387)
Net cash provided by operating activities	$	851,610	666,479

Note: Certain prior year amounts have been reclassified to conform to the current year’s presentation.

See accompanying notes to financial statements.

(1) Summary of Significant Accounting Policies

The Department of Water and Power of the City of Los Angeles (the Department) exists as a separate proprietary department of the City of Los Angeles (the City) under and by virtue of the City Charter enacted in 1925 and as revised effective July 2000. The Department's Power Revenue Fund (the Power System) is responsible for the generation, transmission, and distribution of electric power for sale in the City. The Power System is operated as an enterprise fund of the City.

(a) Method of Accounting

The accounting records of the Power System are maintained in accordance with U.S. generally accepted accounting principles (GAAP) for governmental entities. The financial statements have been prepared using the economic resources measurement focus and the accrual basis of accounting. The Power System is accounted for as an enterprise fund and applies all applicable Governmental Standards Board (GASB) pronouncements in its accounting and reporting. In addition, the Power System follows Financial Accounting Standards Board (FASB) pronouncements issued on or before November 30, 1989, unless those pronouncements conflict with or contradict GASB pronouncements.

The financial statements of the Power System are intended to present the financial position, and the changes in the financial position, and cash flows of only that portion of the business-type activities and each major fund of the City of Los Angeles, California that is attributable to the transactions of the Power System. They do not purport to, and do not, present fairly the financial position of the City of Los Angeles, California as of June 30, 2012 and 2011, the changes in its financial position or, where applicable, its cash flows for the years then ended, in conformity with GAAP.

The Department's rates are determined by the Board of Water and Power Commissioners (the Board) and are subject to review and approval by the Los Angeles City Council (City Council). As a regulated enterprise, the Department utilizes Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*, which requires that the effects of the rate-making process be recorded in the financial statements. Such effects primarily concern the time at which various items enter into the determination of changes in fund net assets. Accordingly, the Power System records various regulatory assets and liabilities to reflect the Board's actions. Regulatory liabilities are recorded in deferred credits and regulatory assets are included as deferred debits and under recovered costs on the balance sheets. Management believes that the Power System meets the criteria for continued application of SFAS No. 71, but will continue to evaluate its applicability based on changes in the regulatory and competitive environment (see notes 3 and 14(d)i).

(b) Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

(c) Utility Plant

The costs of additions to utility plant and replacements of retired units of property are capitalized. Costs include labor, materials, an allowance for funds used during construction (AFUDC), and allocated indirect charges, such as engineering, supervision, transportation and construction equipment, retirement plan contributions, healthcare costs, and certain administrative and general expenses. The costs of maintenance, repairs, and minor replacements are charged to the appropriate operations and maintenance expense accounts.

(d) Intangibles

The Department follows GASB No. 51, *Accounting and Financial Reporting for Intangible Assets* (GASB No. 51), which requires that an intangible asset be recognized in the balance sheet only if it is considered identifiable. Additionally, it establishes a specified-conditions approach to recognize intangible assets that are internally generated. Effectively, outlays associated with the development of such assets are capitalized until certain criteria are met. Outlays incurred prior to meeting these criteria are expensed as incurred. The Power System capitalized internally generated software costs in 2012 and 2011. The capitalized amounts are included in construction work in progress on the balance sheets.

(e) Impairment of Long-Lived Assets

The Department follows GASB Statement No. 42, *Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries* (GASB No. 42). Governments are required to evaluate prominent events or changes in circumstances affecting capital assets to determine whether impairment of a capital asset has occurred. A capital asset is considered impaired when its service utility has declined significantly and unexpectedly. Under GASB No. 42, impaired capital assets that will no longer be used by the government should be reported at the lower of carrying value or fair value. Impairment losses on capital assets that will continue to be used by the government should be measured using the method that best reflects the cause of the diminished service utility of the capital asset.

(f) Depreciation and Amortization

Depreciation expense is computed using the straight-line method based on service lives for all projects completed after July 1, 1973, and for all office and shop structures, related furniture and equipment, and transportation and construction equipment. Depreciation for facilities completed prior to July 1, 1973 is computed using the 5.0% sinking fund method based on estimated service lives. The Department uses the composite method of depreciation and, therefore, groups assets into composite groups for purposes of calculating depreciation expense. Estimated service lives range from 5 to 75 years. Amortization expense for computer software is computed using the straight-line method over five years. Depreciation and amortization expense as a percentage of average depreciable utility plant in service was 3.1% and 3.2% for fiscal years 2012 and 2011, respectively.

(g) Nuclear Decommissioning

The Department owns a 5.70% direct ownership interest in the Palo Verde Nuclear Generating Station (PVNGS). In addition, through its participation in the Southern California Public Power Authority (SCPPA), the Department is party to a contract for an additional 3.95% of the output of PVNGS. Nuclear decommissioning costs associated with the Power System's output entitlement are included in purchased power expense (see note 6).

Decommissioning of PVNGS is expected to commence subsequent to the year 2044, since the Nuclear Regulatory Commission (the NRC) approved a request for license extension in April 2011. However, the owners of PVNGS have not yet amended the participation agreement to extend the term of the agreement to cover the license extension of PVNGS. The total cost to decommission the Power System's direct ownership interest in PVNGS is estimated to be $139 million in 2011 dollars. This estimate is based on an updated site specific study prepared by an independent consultant in 2010. As of June 30, 2012 and 2011, the Power System has recorded $143.2 million and $139.6 million, respectively, to accumulated depreciation to provide for the decommissioning liability.

Prior to December 1999, the Power System contributed $70.2 million to external trusts established in accordance with the PVNGS participation agreement and NRC requirements. During fiscal year 2000, the Department suspended contributing additional amounts to the trust funds, as management believes that contributions made, combined with reinvested earnings, will be sufficient to fully fund the Department's share of decommissioning costs. The Department will continue to reinvest its investment income on the trust investments into the decommissioning trusts. The Department reinvested $3.6 million and $2.2 million of investment income in fiscal years 2012 and 2011, respectively. Decommissioning funds, which are included in restricted investments, totaled $123.6 million and $120.0 million as of June 30, 2012 and 2011 (at fair value), respectively. The Department's current accounting policy recognizes any realized and unrealized investment earnings from nuclear decommissioning trust funds as a component of accumulated depreciation.

(h) Nuclear Fuel

Nuclear fuel is amortized and charged to fuel for generation on the basis of actual thermal energy produced relative to total thermal energy expected to be produced over the life of the fuel. Under the provisions of the Nuclear Waste Policy Act of 1982, the federal government assesses each utility with nuclear operations, including the Power System, $1 per megawatt hour of nuclear generation. The Power System includes this charge as a current year expense in fuel for generation. See note 14 for discussion of spent nuclear fuel disposal.

(i) Natural Gas Field

In July 2005, the Power System acquired approximately a 74.5% ownership interest in gas properties located in Pinedale, Wyoming. The Power System uses the successful efforts method of accounting for its investment in gas producing properties. Costs to acquire the mineral interest in gas producing properties, to drill and equip exploratory wells that find proven reserves, and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proven reserves are expensed. Capitalized costs of gas producing properties are depleted by the unit-of-production method based on the estimated future production of the proved developed producing wells.

Depletion expense related to the gas field is recorded as a component of fuel for generation expense. During fiscal years 2012 and 2011, the Power System recorded $29.1 million and $14.4 million of depletion expense, respectively.

(j) Cash and Cash Equivalents

As provided for by the State of California Government Code (the Code), the Power System's cash is deposited with the City Treasurer in the City's general investment pool for the purpose of maximizing interest earnings through pooled investment activities. Cash and cash equivalents in the City's general investment pool are reported at fair value and changes in unrealized gains and losses are recorded in the statements of revenues, expenses, and changes in fund net assets. Interest earned on such pooled investments is allocated to the participating funds based on each fund's average daily cash balance during the allocation period. The City Treasurer invests available funds of the City and its independent operating departments on a combined basis. The Power System classifies all cash and cash equivalents that are restricted either by creditors, the Board, or by law, as restricted cash and cash equivalents on the balance sheets. The Power System considers its portion of pooled investments in the City's pool to be cash and cash equivalents and the unspent construction funds as long-term restricted cash as cash equivalents.

At June 30, 2012 and 2011, restricted cash and cash equivalents include the following (amounts in thousands):

	June 30	
	2012	**2011**
Bond redemption and interest funds	$ 271,328	194,986
Self-insurance fund	123,897	113,893
Cash and cash equivalents – current portion	395,225	308,879
Construction funds – classified as long-term restricted cash	20,730	552,704
Total restricted cash and cash equivalents	$ 415,955	861,583

(k) Materials and Fuel

Materials and supplies are recorded at average cost. Fuel is recorded at lower of cost or market, on an average cost basis.

(l) Accrued Unbilled Revenue

Accrued unbilled revenue is the receivable for estimated energy sales during the period for which service has been provided but the customer has not been billed.

(m) Restricted Investments

Restricted investments include primarily commercial paper, U.S. government and governmental agency securities, and corporate bonds. Investments are reported at fair value and changes in unrealized gains and losses are recorded in the statements of revenues, expenses, and changes in fund net assets except for Nuclear Decommissioning Trust Funds. The stated fair value of investments is generally based on published market prices or quotations from major investment dealers (see note 7).

(n) Accrued Employee Expenses

Accrued employee expenses include accrued payroll and an estimated liability for vacation leave, sick leave, and compensatory time, which is accrued when employees earn the rights to the benefits. Below is a schedule of accrued employee expenses as of June 30, 2012 and 2011 (amounts in thousands):

		2012	2011
Type of expenses:			
Accrued payroll	$	26,254	23,767
Accrued vacation		48,689	47,649
Accrued sick leave		11,845	11,534
Compensatory time		15,483	14,390
Total	$	102,271	97,340

(o) Debt Expenses

Debt premium, discount, and issue expenses are deferred and amortized to debt expense using the effective-interest method over the lives of the related debt issues. Gains and losses on refundings related to bonds redeemed by proceeds from the issuance of new bonds are amortized to interest expense using the effective-interest over the shorter of the life of the new bonds or the remaining term of the bonds refunded.

(p) Accrued Workers' Compensation Claims

Liabilities for unpaid workers' compensation claims are recorded at their net present value (see note 13).

(q) Customer Deposits

Customer deposits represent deposits collected from customers upon opening of new accounts. These deposits are obtained when the customer does not have a previously established credit history with the Department. Original deposits plus interest are paid to the customer once a satisfactory payment history is maintained, generally after one to three years.

The Department's Water Revenue Fund (Water System) is responsible for collection, maintenance, and refunding of these deposits for all the Department customers, including those of the Power System. As such, the Water System's balance sheets include a deposit liability of $77 million as of

June 30, 2012 and 2011, for all customer deposits collected. In the event that the Water System defaults on refunds of such deposits, the Power System would be required to pay amounts it owes its customers.

(r) Revenues

The Power System's rates are established by a rate ordinance, which is approved by the City Council. The Power System sells energy to the City's other departments at rates provided in the ordinance. The Power System recognizes energy costs in the period incurred and accrues for estimated energy sold but not yet billed.

Effective October 1, 2006, the Energy Cost Adjustment Factor (ECAF), which is a billing factor defined in the electric rate ordinance, was unfrozen. This change allows the Power System to increase or decrease the factor on a quarterly basis in compliance with the ordinance. While this change allows the Power System to fully recover fuel costs, purchased power costs, and other costs outlined in the ordinance, the difference between the amount billed to customers, and the value of the costs allowed to be recovered through the factor create an over/underrecovered amount. Costs that are underrecovered will be recovered in future periods. Amounts overrecovered will be factored into future quarterly rates. As of June 30, 2012 and 2011, the amount of underrecovered costs, including the ECAF and the Reliability Cost Adjustment Factor was $312.4 million and $294.2 million, respectively. These balances are recorded as noncurrent assets on the balance sheets.

Operating revenues are revenues derived from activities that are billable in accordance with the electric rate ordinance approved by the City Council.

(s) Capital Contributions

Capital contributions and other grants received by the Department for constructing utility plant and other activities are recognized when all applicable eligibility requirements, including time requirements, are met.

(t) Allowance for Funds Used during Construction (AFUDC)

An AFUDC charge represents the cost of borrowed funds used for the construction of utility plant. Capitalized AFUDC is included as part of the cost of utility plant and as a reduction of debt expenses. As of June 30, 2012 and 2011, the average AFUDC rates were 6.0% and 5.2%, respectively.

(u) Use of Restricted and Unrestrictive Resources

The Power System's policy is to use unrestricted resources prior to restricted resources to meet expenses to the extent that it is prudent from an operational perspective. Once it is not prudent, restricted resources will be utilized to meet intended obligations.

(v) Reclassifications

Certain prior year amounts have been reclassified to conform to the current year's presentation.

(2) Recent Accounting Pronouncements

(a) GASB Statement No. 59

In fiscal year 2011, the Department adopted GASB Statement No. 59, *Financial Instruments Omnibus* (GASB No. 59). This statement updates and improves existing standards regarding financial reporting and disclosure requirements of certain financial instruments and external investment pools for which significant issues have been identified in practice. The provisions of this Statement are effective for financial statements for periods beginning after June 15, 2010. There was no impact to net assets as of July 1, 2010 as a result of implementation of this pronouncement.

(b) GASB Statement No. 62

In December 2010, the GASB issued Statement No. 62, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements* (GASB No. 62). The requirements in this Statement will improve financial reporting by contributing to the GASB's efforts to codify all sources of generally accepted accounting principles for state and local governments so that they derive from a single source. The requirements of this Statement are effective for financial statements for periods beginning after December 15, 2011, with retroactive application for all periods presented. The Power System has determined there will be no material impact of this pronouncement on the financial statements.

(c) GASB Statement No. 63

In June 2011, the GASB issued Statement No. 63, *Financial Reporting of Deferred Outflows of Resources, Deferred Inflows of Resources, and Net Position* (GASB No. 63). The requirements of this Statement will improve financial reporting by standardizing the presentation of deferred outflows of resources and deferred inflows of resources and their effects on a government's net position. It alleviates uncertainty about reporting those financial statement elements by providing guidance where none previously existed. The provisions of this Statement are effective for financial statements for periods beginning after December 15, 2011. The Power System has determined there will be no material impact of this pronouncement on its deferred outflows that are reported on the balance sheets.

(d) GASB Statement No. 64

In June 2011, the GASB issued Statement No. 64, *Derivative Instruments: Application of Hedge Accounting Termination Provisions – an amendment of GASB Statement No. 53* (GASB No. 64). The objective of this Statement is to clarify whether an effective hedging relationship continues after the replacement of a swap counterparty or a swap counterparty's credit support provider. This Statement sets forth criteria that establish when the effective hedging relationship continues and hedge accounting should continue to be applied. The provisions of this Statement are effective for financial statements for periods beginning after June 15, 2011. The Power System has determined there will be no material impact of this pronouncement on its hedging derivatives accounted for under GASB Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments* (GASB No. 53).

(e) GASB Statement No. 65

In March 2012, the GASB issued Statement No. 65, *Items Previously Reported as Assets and Liabilities* (GASB No. 65). The requirements of this Statement establishes accounting and financial reporting standards that reclassify, as deferred outflows of resources or deferred inflows of resources, certain items that were previously reported as assets and liabilities and recognizes, as outflows of resources or inflows of resources, certain items that were previously reported as assets and liabilities. It will improve financial reporting by clarifying the appropriate use of the financial statement elements deferred outflows of resources and deferred inflows of resources to ensure consistency in financial reporting. The provisions of this Statement are effective for financial statements for periods beginning after December 15, 2012. The Power System has determined there will be no impact of this pronouncement on its deferred outflows that are reported on the balance sheets.

(f) GASB Statement No. 67

In June 2012, the GASB issued Statement No. 67, *Financial Reporting for Pension Plans—an amendment of GASB Statement No. 25* (GASB No. 67). The requirements of this Statement will improve financial reporting primarily through enhanced note disclosures and schedules of required supplementary information that will be presented by the pension plans that are within its scope. The new information will enhance the decision-usefulness of the financial reports of these pension plans, their value for assessing accountability, and their transparency by providing information about measures of net pension liabilities and explanations of how and why those liabilities changed from year to year. The provisions of this Statement are effective for financial statements for periods beginning after June 15, 2013. The Power System is currently evaluating the impact of this pronouncement on financial statements.

(g) GASB Statement No. 68

In June 2012, the GASB issued Statement No. 68, *Accounting and Financial Reporting for Pension Plans—an amendment of GASB Statement No. 27* (GASB No. 68). This Statement establishes standards for measuring and recognizing liabilities, deferred outflows of resources, and deferred inflows of resources, and expense/expenditures. For defined benefit pensions, this Statement identifies the methods and assumptions that should be used to project benefit payments, discount projected benefit payments to their actuarial present value, and attribute that present value to periods of employee service. The provisions of this Statement are effective for financial statements for periods beginning after June 15, 2014. The Power System is currently evaluating the impact of this pronouncement on financial statements.

(3) Regulatory Matters

(a) Federal Regulation of Transmission Access

The Energy Policy Act of 1992 made fundamental changes in the federal regulation of the electric utility industry, particularly in the area of transmission. As amended by the Energy Policy Act, Sections 211, 212, and 213 of the Federal Power Act (FPA) provide the Federal Energy Regulatory Commission (FERC) authority, upon application by any electric utility, federal power marketing agency, or other person or entity generating electric energy for sale or resale, to require a transmitting utility to provide transmission services (including any enlargement of transmission capacity necessary to provide such services) to the applicant at rates, charges, terms, and conditions set by FERC based on standards and provisions in the FPA. Under the Energy Policy Act, electric utilities owned by municipalities and other public agencies, which own or operate electric power transmission facilities that are used for the sale of electric energy at wholesale rates are "transmitting utilities" subject to the requirements of Sections 211, 212, and 213.

FERC has encouraged in the past the voluntary formation of regional transmission organizations (RTOs) independent from owners of generation and other market participants that will provide transmission access on a nondiscriminatory basis to buyers and sellers of power. Investor-owned utilities (IOUs) and publicly owned utilities (POUs) have been encouraged to participate in the formation and operation of RTOs, but POUs are not, at this time, being ordered by FERC to participate. FERC has adopted a "go slow" approach to the issue of RTO formation in the western United States; it is contemporaneously engaged in a wholesale overhaul of the California market design, referred to initially as the Market Design 2002 proceeding and lately as the Market Redesign and Technology Update (MRTU) proceeding. These FERC proceedings will have potential impacts on every electric utility doing business in California. MRTU involves a comprehensive overhaul of the electricity markets administered by California Independent System Operator (CAISO), including the areas of transmission congestion management, trading and scheduling energy in the day ahead, or spot market, improved market power mitigation, and pricing transparency measures and system improvements to increase operational efficiency and enhance reliability, among other things. MRTU was implemented on April 1, 2009. At this time, there is no material impact on the Department. In addition, CAISO has announced its intention to implement further market changes over the next several years.

(b) Federal Energy Legislation of 2005

On August 8, 2005, the Energy Policy Act of 2005 (EPAct) was enacted, the first comprehensive energy legislation in over a decade. One of the most significant provisions of EPAct empowers the Federal Energy Regulatory Commission (FERC) to certify an Electric Reliability Organization (ERO) to improve the reliability of the nation's "bulk power system" through mandatory and enforceable electric reliability standards (in contrast to the long-standing voluntary system). The definition of "bulk power system" does not include facilities used in the local distribution of electric energy. The ERO is to file any proposed reliability standard or modification with FERC. "Reliability standards" are a set of criteria and requirements relating to the reliable operation of the bulk-power system. Such a standard includes requirements for the operation of existing transmission facilities or the design of planned additions or modifications (to the extent necessary) to provide for reliable operation. It does not include, and the ERO may not impose, any requirement to enlarge existing or to construct new transmission or generation facilities. All users, owners, and operators of the bulk-power system are required to comply with the electric reliability standards. The ERO may impose a penalty on a user, owner, or operator for violating a reliability standard, and FERC may order compliance with such a standard and impose a penalty if it finds that a user, owner, or operator is about to engage in an act that would violate a reliability standard.

Based on EPAct authority vested upon the FERC, the FERC approved the North American Electric Reliability Corporation (NERC) as the ERO. Currently, there are more than 100 mandatory NERC and Western Electricity Coordinating Council (WECC) reliability standards, all of which are subject to penalties ranging from $1,000 to $1,000,000, depending on the impact of the violation to reliability and other factors. The Department has implemented a NERC/WECC Reliability Standards Compliance Program to proactively prevent, monitor, and stop potential violations to these standards.

EPAct authorizes FERC to require nondiscriminatory access to transmission facilities owned by municipal, cooperative, and other transmission companies not currently regulated by FERC, unless exercising this authority would violate a private activity bond rule for purposes of Section 141 of the Internal Revenue Code of 1986. FERC is prohibited from requiring any such entities to join RTOs. EPAct also allows FERC to issue permits for the construction of new transmission facilities when states have been unable or unwilling to act and allows load-serving entities to use the firm transmission rights, or equivalent tradable or financial transmission rights, in order to deliver output or purchased energy to the extent required to meet its service obligations. EPAct does not relieve a load-serving entity from any obligation under state or local law to build transmission or distribution facilities adequate to meet its service obligations, or to abrogate preexisting firm transmission service contracts.

EPAct directs FERC to establish, by rule, incentive-based rates for transmission no later than August 2006 and requires FERC to establish market transparency rules for the electric wholesale market (entities that have a de minims market presence are exempt from the rules). EPAct instructs that the market transparency rules must provide for the timely dissemination of information about the availability and prices of wholesale electric energy and transmission service to FERC, state commission, buyers and sellers of wholesale electric energy, users of transmission services, and the public. Within 180 days of EPAct's enactment, FERC and the Commodity Futures Trading Commission are required to enter into a memorandum of understanding regarding information sharing pursuant to these rules.

In addition, EPAct prohibits any person from willfully and knowingly reporting false information to any federal agency on the price of wholesale electricity or availability of transmission capacity, or using (directly or indirectly) any manipulative device in contravention of any FERC rule. EPAct increases civil and criminal penalties, modifies the procedures for review of FERC orders under the FPA, and changes the refund date under the FPA to be effective as of the date an applicable complaint is filed. EPAct also establishes an entity's right to a refund if (i) it makes a short-term sale of electric energy through an organized market in which the rates for the sale are set by a FERC-approved tariff (not by a contract) and (ii) the sale violates the terms of the tariff or applicable FERC rule in effect at the time of the sale.

The Department currently complies with the mandatory NERC/WECC Reliability Standards and with the statutory transmission and market requirements from FERC, and uses other FERC transmission policy as guidance for LADWP's own transmission policy.

(Continued)

(c) Final Rule on Transmission Planning and Cost Allocation – FERC Order No. 1000 (RM10-23-000)

On July 21, 2011, the FERC issued its Final Rule on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, denominated as Order No. 1000 (Docket No. RM10-23-000). The Final Rule, which largely mirrors FERC's proposed rule issued in June 2010, requires public utility transmission providers to:

- develop and participate in a regional planning process that produces a regional transmission plan;
- consider state and federal public policy requirements in transmission planning processes;
- eliminate, with certain exceptions, rights of first refusal contained in FERC-approved tariffs, or contracts that entitle an incumbent utility to build transmission facilities identified in the regional transmission planning processes;
- develop regional cost allocation methods for transmission projects selected in regional transmission plans; and
- coordinate with each neighboring planning region to develop procedures for coordination of planning and methods of cost allocation for interregional transmission projects.

The Final Rule reflects an ambitious effort by FERC to modify its policies in a manner that will result in more efficient and cost-effective transmission planning and support investment in transmission infrastructure. The Final Rule, however, leaves many of the critical details to be worked out at the regional and interregional levels, and subsequently, to be reviewed by FERC in the form of compliance filings.

The Final Rule urges, but does not require, government-owned utilities such as the Department and cooperative utilities to participate in regional transmission planning and cost allocation. FERC indicates that if "nonjurisdictional" transmission owners do not comply with Order No. 1000, they may not meet reciprocity requirements, and thus may have access to third-party transmission services limited.

LADWP is expected to join a regional planning entity to proactively participate in this process, without commitment to cost allocation, as has been clarified and allowed by FERC.

(d) Dodd-Frank Wall Street Reform and Consumer Protection Act

On July 21, 2010, the "Dodd-Frank Wall Street Reform and Consumer Protection Act" (Dodd-Frank) was signed into law. Dodd-Frank was enacted to minimize systemic risk to the U.S. financial system, in part by establishing new rules related to swaps and other derivatives. First, Dodd-Frank generally requires that parties to swap transactions provide collateral for their swaps. This "margining" requirement means that a party to a swap must set aside cash or other collateral to secure its obligations under the swap. Second, Dodd-Frank generally requires that swap transactions be conducted or "cleared" through financial intermediaries. This clearing requirement means that parties generally cannot enter into a swap that is customized to the needs of the parties, as is typically the case for public power and other electric utilities. Dodd-Frank did, however, provide exceptions to both the margining and clearing requirements for "end users" that are using swaps to hedge commercial risks. A third requirement of Dodd-Frank is to impose reporting requirements on swap transactions, including additional reporting for end-user transactions. Finally, Dodd-Frank imposed additional limitations on swaps with "special entities," including public power and other governmental entities, to ensure that these special entities are being properly advised and dealt with fairly in consummating swap transactions. These rules require that a swap counterparty ensure that a special entity has an independent swap advisor and impose on the advisor a duty to act in the best interests of the special entity.

The CFTC has recently finalized a swap dealer definition exempting entities doing less than $3 billion ($8 billion during a transition period) in swaps from being regulated as a "swap dealer", and has further exempted transactions done between not–for–profit utilities from being considered swaps. Unfortunately, the swap dealer definition also includes a $25 million sub-threshold over a 12-month period for entities doing business with "special entities" (e.g., governmental entities such as LADWP) that will cause counterparties that do not want to be swap dealers (e.g., natural gas producers, independent generators, and utility companies) to severely limit their swap activities with government-owned utilities to avoid reaching the $25 million threshold.

Various organizations representing the "special entities" have requested the CFTC to exclude government-owned utilities' swap transactions related to utility operations from counting towards the $25 million de minimus threshold, and rather be subjected to the overall $3 billion threshold. As of this writing, the CFTC has not yet acted on this request.

The overall impact of these CFTC rulings on LADWP cannot be predicted at this time.

(Continued)

(4) Utility Plant

The Power System had the following activities in utility plant during fiscal year 2012 (amounts in thousands):

	Balance July 1, 2011	Additions	Retirements and disposals	Transfers	Balance June 30, 2012
Nondepreciable utility plant:					
Land and land rights	$ 166,137	—	—	—	166,137
Construction work in progress	685,485	665,133	—	(138,767)	1,211,851
Nuclear fuel	44,328	18,607	(13,248)	—	49,687
Natural gas field	256,622	65,448	(29,064)	—	293,006
Total nondepreciable utility plant	1,152,572	749,188	(42,312)	(138,767)	1,720,681
Depreciable utility plant:					
Generation	4,155,019	52,106	(2,047)	76,292	4,281,370
Transmission	942,278	10,792	(35)	14,033	967,068
Distribution	6,001,869	255,548	(240)	37,992	6,295,169
General	1,265,941	46,054	(10,154)	10,450	1,312,291
Total depreciable utility plant	12,365,107	364,500	(12,476)	138,767	12,855,898
Accumulated depreciation:					
Generation	(2,471,119)	(126,647)	2,047	—	(2,595,719)
Transmission	(365,076)	(24,897)	35	—	(389,938)
Distribution	(2,498,732)	(193,288)	240	—	(2,691,780)
General	(751,764)	(43,868)	10,154	—	(785,478)
Total accumulated depreciation	(6,086,691)	(388,700)	12,476	—	(6,462,915)
Total utility plant, net	$ 7,430,988	724,988	(42,312)	—	8,113,664

Depreciation and amortization expense during fiscal year 2012 was $394.0 million.

The Power System had the following activities in utility plant during fiscal year 2011 (amounts in thousands):

	Balance July 1, 2010	Additions	Retirements and disposals	Transfers	Balance June 30, 2011
Nondepreciable utility plant:					
Land and land rights	$ 165,730	407	—	—	166,137
Construction work in progress	431,491	434,434	—	(180,440)	685,485
Nuclear fuel	44,295	12,007	(11,974)	—	44,328
Natural gas field	231,397	39,623	(14,398)	—	256,622
Total nondepreciable utility plant	872,913	486,471	(26,372)	(180,440)	1,152,572
Depreciable utility plant:					
Generation	4,067,327	40,679	(2,382)	49,395	4,155,019
Transmission	920,584	8,138	(10)	13,566	942,278
Distribution	5,645,415	277,681	134	78,639	6,001,869
General	1,187,783	49,350	(10,032)	38,840	1,265,941
Total depreciable utility plant	11,821,109	375,848	(12,290)	180,440	12,365,107
Accumulated depreciation:					
Generation	(2,354,131)	(119,370)	2,382	—	(2,471,119)
Transmission	(334,852)	(30,234)	10	—	(365,076)
Distribution	(2,303,632)	(194,966)	(134)	—	(2,498,732)
General	(722,652)	(39,144)	10,032	—	(751,764)
Total accumulated depreciation	(5,715,267)	(383,714)	12,290	—	(6,086,691)
Total utility plant, net	$ 6,978,755	478,605	(26,372)	—	7,430,988

Depreciation and amortization expense during fiscal year 2011 was $386.9 million.

(5) Jointly Owned Utility Plant

The Power System has direct interests in several electric generating stations and transmission systems, which are jointly owned with other utilities. As of June 30, 2012 and 2011, utility plant includes the following amounts related to the Power System's ownership interest in each jointly owned utility plant (amounts in thousands, except as indicated):

	Ownership interest	Share of capacity (MWs)	Utility plant in service June 30, 2012 Cost	Utility plant in service June 30, 2012 Accumulated depreciation	Utility plant in service June 30, 2011 Cost	Utility plant in service June 30, 2011 Accumulated depreciation
Palo Verde Nuclear Generating Station	5.7%	224	$ 602,408	374,273	593,723	360,094
Navajo Generating Station	21.2	477	345,952	312,378	344,338	302,801
Mohave Generating Station	10.0	—	64,639	57,852	62,763	57,852
Pacific Intertie DC Transmission Line	40.0	1,240	186,301	54,171	183,531	52,941
Other transmission systems	—	Various	89,205	52,027	91,292	49,595
			$ 1,288,505	850,701	1,275,647	823,283

The Power System will incur certain minimal operating costs related to the jointly owned facilities, regardless of the amount or its ability to take delivery of its share of energy generated. The Power System's proportionate share of the operating costs of the joint plants is included in the corresponding categories of operating expenses.

(6) Purchase Power Commitments

As of June 30, 2012, the Power System has entered into a number of energy and transmission service contracts, which involve substantial commitments as follows (amounts in thousands, except as indicated):

	Agency	Agency share	The Power System's interest in agency's share: Interest	Capacity (MWs)	Outstanding principal
Intermountain Power Project	IPA	100.0%	63.0%	1,125	$ 916,295
Palo Verde Nuclear Generating Station	SCPPA	5.9	67.0	151	46,297
Mead-Adelanto Project	SCPPA	68.0	36.0	313	58,073
Mead-Phoenix Project	SCPPA	17.8 – 22.4	25.0	148	12,538
Southern Transmission System	SCPPA	100.0	60.0	1,429	483,815
Milford I Wind	SCPPA	100.0	93.0	188	212,417
Windy Point	SCPPA	100.0	92.0	242	462,219
Linden Wind Energy	SCPPA	100.0	90.0	45*	122,234
Milford II Wind	SCPPA	100.0	95.0	97	149,746

* For the first three years, Power System will receive 100% (50 MWs), unless City of Glendale exercises its option to take 10%.

IPA – The Intermountain Power Agency (IPA) is an agency of the State of Utah established to own, acquire, construct, operate, maintain, and repair the Intermountain Power Project (IPP). The Power System serves as the project manager and operating agent of IPP.

SCPPA – The Southern California Public Power Authority is a California Joint Powers Agency that finances the construction or acquisition of generation, transmission and renewable energy projects.

The above agreements require the Power System to make certain minimum payments, which are based primarily upon debt service requirements. In addition to average annual fixed charges of approximately $357 million during each of the next five years, the Power System is required to pay for operating and maintenance costs related to actual deliveries of energy under these agreements (averaging approximately $526 million annually during each of the next five years). The Power System made total payments under these agreements of approximately $751 million and $678 million in fiscal years 2012 and 2011, respectively. These agreements are scheduled to expire from 2027 to 2035.

The Power System earned fees under the IPP project manager and operating agent agreements totaling $18.9 million and $20.8 million in fiscal years 2012 and 2011, respectively.

(a) Long-Term Notes Receivable

Under the terms of its purchase power agreement with IPA, the Department is charged for its output entitlements based on its share of IPA's costs, including debt service. During fiscal year 2000, the Department restructured a portion of this obligation by transferring $1.11 billion to IPA in exchange for long-term notes receivable. The funds transferred were obtained from the debt reduction trust funds and through the issuance of new variable rate debentures (see notes 7 and 10). IPA used the proceeds from these transactions to defease and to tender bonds with par values of approximately $618 million and $611 million, respectively.

On September 7, 2000, the Department paid $187 million to IPA in exchange for additional long-term notes receivable. IPA used the proceeds to defease bonds with a face value of $198 million.

On July 20, 2005, the Department paid $97 million to IPA in exchange for additional long-term notes receivable. IPA used the proceeds to defease bonds with a face value of $92 million.

The IPA notes are subordinate to all of IPA's publicly held debt obligations. The Power System's future payments to IPA will be partially offset by interest payments and principal maturities from the subordinated notes receivable. The net IPA notes receivable balance totaled $904 million and $1.005 billion as of June 30, 2012 and 2011, respectively.

The IPA notes pay interest and principal monthly and mature on July 1, 2023. The interest rates range from 1.9% to 14.2%, subject to adjustments related to IPA bond refundings.

(b) Energy Entitlement

The Department has a contract through 2017 with the U.S. Department of Energy for the purchase of available energy generated at the Hoover Power Plant. The Department's contractual share of contingent capacity at Hoover is 491 MW (maximum rated capability). The cost of power (approximately 455 MW of capacity and 599,000 MWH of energy) purchased under this contract, including the Lower Colorado River Basin Development Fund Contribution Charge, was approximately $18 million and $17 million as of June 30, 2012 and 2011, respectively.

On December 20, 2011, the President signed H.R. 470, the "Hoover Power Allocation Act of 2011," into law. The legislation reallocates, for 50 more years, power from the Hoover Dam Power Plant to existing contractors while creating an additional pool of 5% power for new entrants.

The Department has a contract through 2026 with SCPPA for the purchase of available energy generated at the Pebble Springs Wind Project located in Gilliam County, Oregon. The Power System's share of capacity at Pebble Springs is approximately 69 MWs (maximum capacity). The cost of power purchased under this contract was $18 million as of June 30, 2012 and 2011.

(c) Electricity Swap and Forward Contracts

In order to obtain the highest market value on energy that is sold into the wholesale market, the Department monitors the sales price of energy, which varies based on which hub the energy is to be delivered. There are three primary hubs within the Department's transmission region: Palo Verde, California Oregon Border, and Mead. The Department enters into various locational swap transactions with other electric utilities in order to effectively utilize its transmission capacity and to achieve the most economical exchange of energy purchased and sold.

The Department procures renewable energy resources located remotely. These resources provide intermittent and limited source of energy and these resources are not directly connected to the Department's transmission system. In order to receive firm renewable energy, the Department entered into a green for green energy exchange with the same or different Renewable Energy Credit source.

The Department enters into power and natural gas forward contracts in order to meet the electricity requirements to serve its customers. To assist the Department in achieving its Renewable Portfolio Standards (RPS) goal of 20%, some of the forward purchases made are renewable energy and biomethane gas.

The Department does not enter into swap and forward transactions for trading purposes. All of these transactions are intended to be used in the Department's normal course of operations. The Department is exposed to risk of nonperformance if the counterparties default or if the swap agreements are terminated.

As of June 30, 2012, the Power System had the following Electricity Swap and Forward Contracts, which are not recorded in the Power System's financial statements based on the criteria in GASB No. 53 (amounts in thousands):

Description	Notional amount (total contract quantities)	Contract price range dollar per unit	First effective date	Last termination date	Fair value	Cash paid at inception
Electricity swaps:						
Purchases	325,760 MW	$ 29.00 – 34.75	07/01/12	12/31/12	$ (10,101)	—
Sales	325,760 MW	33.31 – 35.50	07/01/12	12/31/12	10,953	—
Forward contracts:						
Electricity	260,274 MW	12.00 – 47.98	07/01/12	06/30/13	604	—
Natural gas	50,314,600 MMBtu	5.49 – 10.85	07/01/12	10/31/21	(295,805)	—

As of June 30, 2011, the Power System had the following Electricity Swap and Forward Contracts, which are not recorded in the Power System's financial statements (amounts in thousands):

Description	Notional amount (total contract quantities)	Contract price range dollar per unit	First effective date	Last termination date	Fair value	Cash paid at inception
Electricity swaps:						
Purchases	264,960 MW	$ 44.20 – 46.90	07/01/11	12/31/11	$ (816)	—
Sales	264,960 MW	46.70 – 49.40	07/01/11	12/31/11	1,478	—
Forward contracts:						
Electricity	600,160 MW	9.52 – 75.67	07/01/11	12/31/11	(2,328)	—
Natural gas	26,782,400 MMBtu	5.28 – 9.80	07/01/11	07/31/14	(91,108)	—

(7) Cash, Cash Equivalents, and Investments

(a) Restricted and Other Investments

A summary of the Power System's restricted and other investments is as follows (amounts in thousands):

	June 30 2012	June 30 2011
Restricted and other investments:		
Restricted investments:		
Debt Reduction Trust Funds	$ 490,444	485,609
Nuclear Decommissioning Trust Funds	123,627	120,008
Natural Gas Trust Fund	268	129
Hazardous Waste Treatment Trust Fund	2,177	2,165
SCPPA Palo Verde investment	22,605	26,497
Total restricted investments	$ 639,121	634,408

The Power System also has $0 and $69,534 of cash collateral received from securities lending transactions in the City's securities lending program as of June 30, 2012 and 2011, respectively (see notes 7(b) and 8).

All restricted and other investments are to be used for a specific purpose as follows:

Debt Reduction Trust Funds

The debt reduction trust funds were established during fiscal year 1997 to provide for the payment of principal and interest on long-term debt obligations and purchased power obligations arising from the Department's participation in IPP and SCPPA (see note 6). The Department has transferred funds from purchased power precollections into these trust funds. Funds from operations may also be transferred by management as funds become available.

Nuclear Decommissioning Trust Funds

Nuclear decommissioning trust funds will be used to pay the Department's share of decommissioning PVNGS at the end of its useful life (see note 1).

Natural Gas Trust Fund

The natural gas trust fund was established to serve as depository to pay for costs and to post margin or collateral in connection with contracts for the purchase and delivery of financial transactions for natural gas. These transactions are entered into to stabilize the natural gas portion of the Department's fuel for generation costs.

Hazardous Waste Treatment Storage and Disposal Trust Fund

The hazardous waste treatment storage and disposal trust fund was established to provide financial assurance for closure of the Main Street treatment and disposal facility.

SCPPA Palo Verde Investment

The SCPPA Palo Verde investment is a fixed rate investment held by SCPPA to be drawn down over the next six years to pay for purchased power obligations arising from the Department's participation in the SCPPA Palo Verde project. The fixed interest rate is 4.97% and the maturity date is June 25, 2017.

As of June 30, 2012, the Power System's securities lending cash collateral and restricted investments and their maturities are as follows (in thousands):

		Investment maturities				
Investment type	**Fair value**	**1 to 30 days**	**31 to 60 days**	**61 to 365 days**	**366 days to 5 years**	**Over 5 years**
U.S. agencies	$ 358,744	—	—	6,374	288,421	63,949
Medium-term corporate notes	113,650	388	1,004	35,215	77,043	—
Commercial paper	39,726	4,999	—	34,727	—	—
Certificates of deposit	35,022	11,001	—	24,021	—	—
California local agency bonds	42,614	5,000	—	16,287	21,327	—
California state bonds	8,718	—	—	—	8,718	—
Bankers' acceptances	505	—	—	505	—	—
Money market funds	17,537	17,537	—	—	—	—
SCPPA Palo Verde investment	22,605	—	—	—	22,605	—
	$ 639,121	38,925	1,004	117,129	418,114	63,949

As of June 30, 2011, the Power System's securities lending cash collateral and restricted investments and their maturities are as follows (in thousands):

		Investment maturities				
Investment type	**Fair value**	**1 to 30 days**	**31 to 60 days**	**61 to 365 days**	**366 days to 5 years**	**Over 5 years**
U.S. agencies	$ 393,849	5,005	—	—	313,479	75,365
Medium-term corporate notes	43,335	5,484	5,546	10,931	21,374	—
Commercial paper	95,775	16,804	23,297	55,674	—	—
Certificates of deposit	27,005	12,000	10,001	5,004	—	—
Municipal commercial paper	5,000	—	5,000	—	—	—
California local agency bonds	23,543	12,775	—	6,686	4,082	—
California state bonds	—	—	—	—	—	—
Bankers' acceptances	500	—	500	—	—	—
Money market funds	18,904	18,904	—	—	—	—
SCPPA Palo Verde investment	26,497	—	—	—	—	26,497
	$ 634,408	70,972	44,344	78,295	338,935	101,862

i. Interest Rate Risk

The Department's investment policy limits the maturity of its investments to a maximum of 30 years for U.S. government agency securities; 5 years for medium-term corporate notes, California local agency obligations, and California state obligations and municipal bonds; 270 days for commercial paper; 397 days for certificates of deposit; 180 days for bankers' acceptances; and 45 days for repurchase agreements purchased with cash collateral from securities lending agreements.

ii. Credit Risk

Under its investment policy and the Code, the Department is subject to the prudent investor standard of care in managing all aspects of its portfolios. The prudent investor standard requires that the Department "…shall act with care, skill, prudence, and diligence under the circumstances then prevailing, including, but not limited to, the general economic conditions and the anticipated needs of the agency, that a prudent person acting in a like capacity and in familiarity with those matters would use in the conduct of funds of a like character and with like aims, to safeguard the principal and maintain the liquidity needs of the agency."

The U.S. government agency securities in the portfolio consist of securities issued by government-sponsored enterprises, which are not explicitly guaranteed by the U.S. government. Of the U.S. government agency securities in the portfolio as of June 30, 2012, $330,708,464 (92%) was rated with either the highest or second highest possible credit ratings by the Nationally Recognized Statistical Rating Organizations (NRSROs) that rated them and $28,035,284 (8%) was not rated. As of June 30, 2011, the U.S. government securities in the portfolio carried the highest possible ratings by all of the NRSROs that rated them.

The Department's investment policy specifies that medium-term corporate notes must be rated in a rating category of "A" or its equivalent or better by a NRSRO. Of the Power System's investments in corporate notes as of June 30, 2012, $8,067,221 (7%) was rated in the category of AAA, $59,342,325 (52%) was rated in the category of AA and $45,848,830 (40%) was rated in the category of A by at least one NRSRO. The remaining $387,999 (less than 1%) of investments in corporate notes were not rated. Of the Power System's investments in corporate notes as of June 30, 2011, $38,748,005 (89%) was rated in the category of AA and $4,112,825 (10%) was rated in the category of A by at least one NRSRO. The remaining $474,169 (1%) of investments in corporate notes were not rated.

The Department's investment policy specifies that commercial paper must be of the highest ranking or of the highest letter and number rating as provided for by at least two NRSROs. As of June 30, 2012 and 2011, all of the Power System's investments in commercial paper were rated with at least the highest letter and number rating as provided by at least two NRSROs.

The Department's investment policy specifies that negotiable certificates of deposit must be of the highest ranking or letter and number rating as provided for by at least two NRSROs and that for nonnegotiable certificates of deposit, the full amount of principal and interest is insured by the Federal Deposit Insurance Corporation (FDIC) or National Credit Union Administration. As of June 30, 2012, the Power System's investments in certificates of deposits included $34,021,657 of negotiable certificates of deposit with at least the highest letter and number rating as provided by at least two NRSROs and $1,000,000 of nonnegotiable certificates of deposit fully insured by the FDIC. As of June 30, 2011, the Power System's investments in certificates of deposits included $26,005,303 of negotiable certificates of deposit with at least the highest letter and number rating as provided by at least two NRSROs and $1,000,000 of nonnegotiable certificates of deposit fully insured by the FDIC. The

Department's investment policy specifies that California local agency obligations, which include municipal commercial paper, must be rated in a rating category of "A" or its equivalent or better by a NRSRO. Of the Power System's investments in California municipal commercial paper as of June 30, 2011, $5,000,000 (100%) was rated with the highest short-term letter and number rating by two NRSROs. Of the Power System's investments in California local agency bonds as of June 30, 2012, $6,034,780 (14%) was rated in the category of AAA; $17,101,513 (40%) was rated in the category of AA; $6,205,572 (15%) was rated in the category of A; and $13,272,640 (31%) was rated with the highest short-term ranking as provided by at least one NRSRO. Of the Power System's investments in California local agency bonds as of June 30, 2011, $9,767,100 (41%) was rated in the category of AAA; $6,744,355 (29%) was rated in the category of AA; $2,026,557 (9%) was rated in the category of A; and $5,004,500 (21%) was rated with the highest short-term ranking as provided by at least one NRSRO.

The Department's investment policy specifies that State of California obligations must be rated in a rating category of "A" or its equivalent or better by a NRSRO. As of June 30, 2012, all of the Power System's investments in State of California Obligations were rated in the rating category of A by at least one NRSRO. As of June 30, 2011, the Power System did not hold any investments in State of California obligations.

The Department's investment policy specifies that banker's acceptances must be of the highest ranking or letter and number rating as provided for by at least two NRSROs. As of June 30, 2012 and 2011, all of the Power System's investments in banker's acceptances were rated with the highest letter and number rating as provided by three NRSROs.

The Department's investment policy specifies that money market funds may be purchased as allowed under the Code, which requires that the fund must have either 1) attained the highest ranking or highest letter and numerical rating provided by not less than two NRSROs or 2) retained an investment advisor registered or exempt from registration with the Securities and Exchange Commission with not less than five years' experience in managing money market mutual funds with assets under management in excess of $500 million. As of June 30, 2012 and 2011, each of the money market funds in the portfolio had the highest possible ratings by at least two NRSROs.

iii. Concentration of Credit Risk

The Department's investment policy specifies that there is no percentage limitation on the amount that can be invested in U.S. government agency securities, except that a maximum of 30% of the cost value of the portfolio may be invested in the securities of any single U.S. government agency issuer.

Of the Power System's total investments as of June 30, 2012, $121,438,988 (19%) was invested in securities issued by the Federal National Mortgage Association; $88,677,400 (14%) was invested in securities issued by the Federal Home Loan Mortgage Corporation; $85,555,628 (13%) was invested in securities issued by the Federal Home Loan Bank; and $35,036,448 (5%) was invested in securities issued by the Federal Farm Credit Bank.

(Continued)

Of the Power System's total investments as of June 30, 2011, $147,535,173 (23%) was invested in securities issued by the Federal National Mortgage Association; $128,982,034 (20%) was invested in securities issued by the Federal Home Loan Mortgage Corporation; and $101,033,649 (16%) was invested in securities issued by the Federal Home Loan Bank.

(b) Pooled Investments

The Power System's cash, cash equivalents, and its collateral value of the City's securities lending program (SLP) are included within the City Treasury's general and special investment pool (the Pool). As of June 30, 2012 and 2011, the Power System's share of the City's general and special investment pool was $833,850,000 and $1,492,530,000, which represents approximately 10% and 17% of the Pool, respectively.

The cash balances of substantially all funds on deposit in the City Treasury are pooled and invested by the City Treasurer for the purpose of maximizing interest earnings through pooled investment activities but safety and liquidity still take precedence over return. Interest earned on pooled investments is allocated to the participating funds based on each fund's average daily deposit balance during the allocation period with all remaining interest allocated to the General Fund. Investments in the City Treasury are stated at fair value based on quoted market prices except for commercial paper and money market investments that have remaining maturities of one year or less at time of purchase, which are reported at amortized cost.

Pursuant to California Government Code Section 53607 and the Los Angeles City Council File No. 94-2160, the City Treasury shall render to the City Council a statement of investment policy (the Policy) annually. City Council File No. 09-3050 was adopted on January 27, 2010 as the City's investment policy. This Policy shall remain in effect until the Los Angeles City Council and the Mayor approve a subsequent revision. The Policy governs the City's pooled investment practices. The Policy addresses soundness of financial institutions in which the City Treasurer will deposit funds and types of investment instruments permitted by California Government Code Sections 53600-53635 and 16429.1.

Examples of investments permitted by the Policy are obligations of the U.S. Treasury and government agencies, commercial paper notes, certificates of deposit (CD) placement service, bankers' acceptances, medium-term notes, mutual funds, money market mutual funds, and the State of California Local Agency Investment Fund.

At June 30, 2012, the investments held in the City Treasury's General and Special Investment Pool Programs and their maturities are as follows (in thousands):

Type of Investments	Amount	Investment Maturities 1 to 30 Days	31 to 60 Days	61 to 365 Days	366 Days To 5 Years	Over 5 Years
U.S. Treasury Notes	$ 3,773,466	1,988	—	62,617	3,689,504	19,357
U.S. Treasury Bills	37,004	28,035	6,009	2,960	—	—
U.S. Sponsored Agency Issues	2,018,682	164,006	562,587	207,749	1,073,235	11,105
Medium term notes	1,318,929	14,500	—	195,072	1,109,357	—
Commercial paper	829,790	741,152	88,638	—	—	—
Certificates of deposit	6,000	—	—	6,000	—	—
Short term investment funds	4,447	4,447	—	—	—	—
Total general and special pools	$ 7,988,318	954,128	657,234	474,398	5,872,096	30,462

Interest Rate Risk. The Policy limits the maturity of its investments to five years for the U.S. Treasury and government agency securities, medium term notes, CD placement service, collateralized bank deposits, mortgage pass-through securities, and bank/time deposits; one year for repurchase agreements; 270 days for commercial paper; 180 days for bankers' acceptances, and 92 days for reverse repurchase agreements. The Policy also allows City funds with longer-term investments horizons, to be invested in securities that at the time of the investment have a term remaining to maturity in excess of five years, but with a maximum final maturity of thirty years.

Credit Risk. The Policy establishes minimum credit ratings requirement for investments. There is no credit quality requirement for local agency bonds, U.S. Treasury Obligations, State of California Obligations, California Local Agency Obligations, and U.S. Sponsored Agencies (U.S. government sponsored enterprises) securities. The City's $2.0 billion investments in U.S. government sponsored enterprises consist of securities issued by the Federal Home Loan Bank – $581.8 million, Federal National Mortgage Association – $602.4 million, Federal Home Loan Mortgage Corporation – $646.1 million, Federal Farm Credit Bank – $124.0 million, and Tennessee Valley Authority – $64.4 million. Of the City's $2.0 billion investments in U.S. Sponsored Agencies securities, $1,253.9 million were rated "AA+" by S&P and "Aaa" by Moody's; $764.8 million were not rated individually by S&P nor Moody's (issuers of these securities are rated "A-1+" by S&P and "P-1" by Moody's).

Medium term notes must be issued by corporations organized and operating within the United States or by depository institutions licensed by the United States or any state and operating within the United States. Medium term notes must have at least an "A" rating. The City's $1.3 billion investments in medium term notes consist of securities issued by banks and corporations that comply with these requirements and were rated "A" or better by S&P and "A3" or better by Moody's. Subsequent to purchase, two issuers representing $27.5 million (2.1%) in investments were downgraded to "BBB+" by S&P.

Commercial paper issues must have a minimum of "A-1" or equivalent rating. If the issuer has issued long-term debt, it must be rated "A" without regard to modifiers. Issuing corporation must be organized and operating within the United States and have assets in excess of $500.0 million. Of the City's $829.8 million investments in commercial paper, $709.8 million were rated A-1+/A-1 by S&P and P-1 by Moody's; $120.0 million were not rated individually by S&P nor Moody's. The issuers of the certificates of deposit were not rated.

Concentration of Credit Risk. The Policy does not allow more than 40% of its investment portfolio be invested in commercial paper and bankers' acceptances, 30% in certificates of deposit and medium term notes, 20% in mutual funds, money market mutual funds and mortgage pass-through securities. The Policy further provides for a maximum concentration limit of 10% in any one issuer of commercial paper as well as in any one mutual fund, and 30% in bankers' acceptances of any one commercial bank. There is no percentage limitation on the amount that can be invested in the U.S. government agencies. The City's pooled investments comply with these requirements. GAAP requires disclosure of certain investments in any one issuer that represent 5% or more of total investments. Of the City's total pooled investments as of June 30, 2012, $581.8 million (7%) was invested in securities issued by the Federal Home Loan Bank, $646.1 million (8%) was invested in securities issued by Federal Home Loan Mortgage Corporation, and $602.4 million (8%) was invested in securities issued by Federal National Mortgage Association.

At June 30, 2011, the investments held in the City Treasury's General and Special Investment Pool Programs and their maturities are as follows (in thousands):

		Investment maturities				
Type of investments	**Amount**	**1 to 30 Days**	**31 to 60 Days**	**61 to 365 Days**	**366 Days to 5 years**	**Over 5 years**
U.S. Treasury notes	$ 3,541,794	—	—	38,482	3,490,201	13,111
U.S. Treasury bills	92,789	5,984	15,864	70,941	—	—
U.S. Sponsored Agency Issues	2,563,178	455,933	110,660	782,630	1,212,938	1,017
Medium-term notes	1,126,648	—	—	148,980	977,668	—
Commercial paper	607,177	388,945	130,749	87,483	—	—
Certificates of deposit	8,000	—	—	8,000	—	—
Short-term investment funds	22,425	22,425	—	—	—	—
Securities lending cash collateral:						
U.S. Treasury notes	406,157	—	—	—	406,157	—
U.S. Sponsored Agency Issues	259,335	—	—	—	259,335	—
Total general and special pools	$ 8,627,503	873,287	257,273	1,136,516	6,346,299	14,128

Interest Rate Risk. The Policy limits the maturity of its investments to five years for the U.S. Treasury and government agency securities, medium-term notes, CD placement service, collateralized bank deposits, mortgage pass-through securities, and bank/time deposits; one year for repurchase agreements; 270 days for commercial paper; 180 days for bankers' acceptances, and 92 days for reverse repurchase agreements. The Policy also allows City funds with longer-term investments horizons, to be invested in securities that at the time of the investment have a term remaining to maturity in excess of five years, but with a maximum final maturity of thirty years.

Credit Risk. The Policy establishes minimum credit ratings requirements for investments. There is no credit quality requirement for local agency bonds, U.S. Treasury Obligations, State of California Obligations, California Local Agency Obligations, and U.S. Sponsored Agencies (U.S. government sponsored enterprises) securities. The City's $2.6 billion investments in U.S. government sponsored enterprises consist of securities issued by the Federal Home Loan Bank – $866.0 million, Federal National Mortgage Association – $748.1 million, Federal Home Loan Mortgage Corporation – $738.9 million, Federal Farm Credit Bank – $164.4 million, Tennessee Valley Authority – $37.9 million, and Federal Agricultural Mortgage Corporation – $7.8 million. Of the City's $2.6 billion investments in U.S. Sponsored Agencies securities, $1,733.9 million are rated "AAA" by S&P and "Aaa" by Moody's; $821.5 million are not rated individually by S&P nor Moody's (issuers of these securities are rated "A-1+" by S&P and "P-1" by Moody's); and $7.8 million are not rated. In August 2011, Standard & Poor's lowered the long-term U.S. debt credit rating from "AAA" to "AA+." This downgrade affects the credit risk associated with the City's investments in certain U.S. Sponsored Agencies securities.

Medium-term notes must be issued by corporations organized and operating within the United States or by depository institutions licensed by the United States or any state and operating within the United States. Medium-term notes must have at least an "A" rating. The City's $1.1 billion investments in medium-term notes consist of securities issued by banks and corporations that comply with these requirements and were rated "A" or better by S&P and "A3" or better by Moody's.

Commercial paper issues must have a minimum of "A-1" or equivalent rating. If the issuer has issued long-term debt, it must be rated "A" without regard to modifiers. Issuing corporation must be organized and operating within the United States and have assets in excess of $500.0 million.

The City's $607.2 million investments in commercial paper comply with these requirements and were rated "A-1+/A-1" by S&P and "P-1" by Moody's.

The issuers of the certificates of deposit were not rated.

Concentration of Credit Risk. The Policy does not allow more than 40% of its investment portfolio be invested in commercial paper and bankers' acceptances, 30% in certificates of deposit and medium-term notes, 20% in mutual funds, money market mutual funds, and mortgage pass-through securities. The Policy further provides for a maximum concentration limit of 10% in any one issuer of commercial paper as well as in any one mutual fund, and 30% in bankers' acceptances of any one commercial bank. There is no percentage limitation on the amount that can be invested in the U.S. government agencies. The City's pooled investments comply with these requirements. GAAP requires disclosure of certain investments in any one issuer that represent 5% or more of total investments. Of the City's total pooled investments as of June 30, 2011, $866.0 million (10%) was invested in securities issued by the Federal Home Loan Bank, $738.9 million (9%) was invested in securities issued by Federal Home Loan Mortgage Corporation, and $748.1 million (9%) was invested in securities issued by Federal National Mortgage Association.

(8) Securities Lending Transactions

The Power System participates in an SLP. As of June 30, 2012 and 2011, amounts held in the City of Los Angeles Program are as follows (collateral amounts in thousands):

		June 30	
Program		**2012**	**2011**
City of Los Angeles Program	$	—	69,534

General Investment Pool Program

The Power System participates in the City's SLP through the pooled investment fund. The Department recognizes its proportionate share of the cash collateral received for securities loaned and the related obligation for the general investment pool. Securities lending is permitted and limited under provisions of California Government Code Section 53601. The City Council approved the SLP on October 22, 1991 under Council File No. 91–1860, which complies with the California Government Code. The objectives of the SLP in priority order are: safety of loaned securities and prudent investment of cash collateral to enhance revenue from the investment program. The SLP is governed by a separate policy and guidelines.

The City's custodial bank acts as the securities lending agent. In the event a counterparty defaults by reason of an act of insolvency, the bank shall take all actions which it deems necessary or appropriate to liquidate permitted investment and collateral in connection with such transaction and shall make a reasonable effort for two business days (Replacement Period) to apply the proceeds thereof to the purchase of securities identical to the loaned securities not returned. If during the Replacement Period the collateral liquidation proceeds are insufficient to replace any of the loaned securities not returned, the bank shall, subject to payment by the City of the amount of any losses on any permitted investments, pay such additional amounts as necessary to make such replacement.

Under the provisions of the SLP, and in accordance with the California Government Code, no more than 20% of the market value of the General Investment Pool (the Pool) is available for lending. The City receives cash as collateral on loaned securities, which is reinvested in securities permitted under the Policy. In accordance with the California Government Code, the securities lending agent marks to market the value of both the collateral and the reinvestments daily. Except for open loans where either party can terminate a lending contract on demand, term loans have a maximum life of 92 days. Earnings from securities lending accrue to the Pool and are allocated on a pro rata basis to all Pool participants.

During the fiscal year 2012, collateralizations on all loaned securities were compliant with the required 102% of the market value. The City can sell collateral securities only in the event of borrower default. The lending agent provides indemnification for borrower default. There were no violations of legal or contractual provisions and no borrower or lending agent default losses during the fiscal year. There was no credit risk exposure to the City because the amounts owed to the borrowers exceeded the amounts borrowed. Loaned securities are held by the City's agents in the City's name and are not subject to custodial credit risk. On May 31, 2012, the City temporarily suspended its SLP due to ongoing Request for Proposals (RFP) for a securities lending agent. The City will likely resume its SLP upon execution of a contract with a selected agent.

(9) Derivative Instruments

In June 2008, GASB issued GASB No. 53. The statement specifically requires governments to measure and report most derivative instruments at fair value in their financial statements that are prepared using the economic resources measurement focus and the accrual basis of accounting. The requirement of reporting the derivative instruments at fair value on the face of the basic financial statements gives the users of those statements a clearer look into the risks their governments are sometimes exposed to when they enter into these transactions and how those risks are managed. The statement also addresses hedge accounting requirements and improves disclosures, providing a summary of the government's derivative instrument activity, its objectives for entering into derivative instruments, and their significant terms and risks. The Power System implemented GASB No. 53 in the 2010 fiscal year.

In accordance with GASB No 53, the Power System records the fair value of its hedging derivative instruments, financial natural gas hedges, on the statement of net assets. As of June 30, 2012 and 2011, the fair values of the financial natural gas hedges were approximately $(91.3) million and approximately $(73.8) million, respectively.

(a) Financial Natural Gas Hedges

The Department enters into natural gas hedging contracts in order to stabilize the cost of gas needed to produce electricity to serve its customers. It is designed to cap gas prices over a portion of the forecasted gas requirements.

The Department does not speculate when entering into financial transactions. Financial hedges are variable to fixed rate swaps and are layered by volumetric averaging. The Department is exposed to financial settlement risk if the counterparties default and/or the agreements are terminated.

As of June 30, 2012, the Power System's financial natural gas hedges by fiscal year are the following (amounts in thousands):

Derivative description	Notional amount (Total contract quantities*)	Contract price range dollar per unit	First effective date	Last termination date	Fair value	Cash paid at derivative inception
Financial natural gas:						
FY 2012-13	$ 6,387,500	5.96 – 8.31	07/01/12	06/30/13	$ (24,631)	—
FY 2013-14	5,027,000	6.37 – 8.31	07/01/13	06/30/14	(17,221)	—
FY 2014-15	5,384,500	6.37 – 9.38	07/01/14	06/30/15	(18,412)	—
FY 2015-16	4,488,000	6.42 – 9.85	07/01/15	06/30/16	(15,312)	—
FY 2016-17	3,197,500	6.61 – 9.83	07/01/16	06/30/17	(10,317)	—
FY 2017-18	2,190,000	6.76 – 7.14	07/01/17	06/30/18	(5,403)	—
Total	$ 26,674,500	5.96 – 9.85	07/01/11	06/30/18	$ (91,296)	—

* Contract quantities in MMBtu – Million British Thermal Units.

As of June 30, 2011, the Power System's financial natural gas hedges by fiscal year were the following (amounts in thousands):

Derivative description		Notional amount (Total contract quantities*)	Contract price range dollar per unit	First effective date	Last termination date		Fair value	Cash paid at derivative inception
Financial natural gas:								
FY 2011-12	$	8,240,000	5.53 – 8.27	07/01/11	06/30/12	$	(21,267)	—
FY 2012-13		6,387,500	5.96 – 8.31	07/01/12	06/30/13		(14,355)	—
FY 2013-14		5,027,000	6.37 – 8.31	07/01/13	06/30/14		(10,712)	—
FY 2014-15		5,384,500	6.37 – 9.38	07/01/14	06/30/15		(11,357)	—
FY 2015-16		4,488,000	6.42 – 9.85	07/01/15	06/30/16		(8,865)	—
FY 2016-17		3,197,500	6.61 – 9.83	07/01/16	06/30/17		(5,320)	—
FY 2017-18		2,190,000	6.76 – 7.14	07/01/17	06/30/18		(1,894)	—
Total	$	34,914,500	5.53 – 9.85	07/01/11	06/30/18	$	(73,770)	—

* Contract quantities in MMBtu – Million British Thermal Units.

The fair value of the natural gas hedges decreased by $17.5 million and is reported as a deferred outflow on the statement of net assets. All fair values were estimated using forward market prices available from broker quotes and exchanges.

(b) Credit Risk

The Power System is exposed to credit risk related to nonperformance by its wholesale counterparties under the terms of contractual agreements. In order to limit the risk of counterparty default, the Department has implemented a Wholesale Marketing Counterparty Evaluation Policy, which was amended and renamed as Counterparty Evaluation Credit Policy (the Counterparty Policy), and was approved by the Board on May 6, 2008. Under the new policy, the scope has been expanded beyond physical power to include transmission, physical natural gas, and financial natural gas. Also, the credit limit structure has been categorized into short-term and long-term structures where the short-term structure is applicable to transactions with terms of up to 18 months and the long-term structure to cover transactions beyond 18 months.

The Policy includes provisions to limit risk including: the assignment of internal credit ratings to all Department's counterparties based on counterparty and/or debt ratings; the use of expected default frequency equivalent credit rating for short-term transactions; the requirement for credit enhancements (including advance payments, irrevocable letters of credit, escrow trust accounts, and parent company guarantees) for counterparties that do not meet an acceptable level of risk; and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty.

As of June 30, 2012, the 10 financial natural gas hedge counterparties were rated by Moody's as follows: three at Aa3, three at A2, three at A3, and one at Baa1. The counterparties were rated by S&P as follows: two at AA-, two at A+, four at A, and two at A-. As of June 30, 2011, the 11 financial natural gas hedge counterparties were rated by Moody's as follows: two at Aa1, one at Aa2, two at Aa3, three at A1, and three at A2. The counterparties were rated by S&P as follows: one at AA, three at AA-, two at A+, and five at A.

Based on the International Swap Dealers Association agreements, the Department or the counterparty may be required to post collateral to support the financial natural gas hedges subject to credit risk in the form of cash, negotiable debt instruments (other than interest-only and principal-only securities), or eligible letters of credit. Collateral posted is held by a custodian. As of June 30, 2012 and 2011, the fair values of the financial natural gas hedges are within the credit limits and collateral posting was not required.

(c) Basis Risk

The Department is exposed to basis risk between the financial natural gas hedges, which are settled monthly at NW Rocky Mountains Index, and the hedged gas deliveries, which are daily spot purchases at Kern River, Opal prices. However, these pricing points are in the same region and are highly correlated.

(d) Termination Risk

The Power System or its counterparties may terminate the contractual agreements if the other party fails to perform under the terms of the contract. No termination events have occurred and there are no out-of-the-ordinary termination events contained in contractual documents.

(Continued)

(10) Long-Term Debt

Long-term debt outstanding as of June 30, 2012 and 2011 consists of revenue bonds and refunding revenue bonds due serially in varying annual amounts as follows (amounts in thousands):

Bond issues	Date of issue	Effective-interest rate	Fiscal year of last scheduled maturity	Principal outstanding 2012	Principal outstanding 2011
Issue of 2001, Series B	06/05/01	Variable	2035	$ 580,800	580,800
Issue of 2001, Series C1	11/15/01	4.788	2017	2,003	2,976
Issue of 2002, Series A	08/22/02	Variable	2036	388,500	388,500
Issue of 2002, Series C2	11/22/02	4.375	2018	8,094	8,208
Issue of 2003, Series A1	07/31/03	3.409	2017	184,955	224,150
Issue of 2003, Series A2	08/19/03	4.662	2032	515,830	515,830
Issue of 2003, Series B	08/28/03	5.013	2036	128,225	128,225
Issue of 2004, Series C3	04/07/04	4.298	2020	7,229	7,369
Issue of 2005, Series A1	12/28/05	4.700	2041	544,285	556,170
Issue of 2005, Series A2	12/28/05	4.700	2031	315,195	315,195
Issue of 2006, Series C4	03/01/06	4.040	2017	5,204	6,339
Issue of 2007, Series A1	10/18/07	4.659	2040	333,630	334,630
Issue of 2007, Series A2	10/18/07	4.638	2033	191,125	191,125
Issue of 2008, Series A1	11/25/08	5.583	2039	200,000	200,000
Issue of 2008, Series A1	11/25/08	5.039	2033	343,420	350,000
Issue of 2009, Series A	02/19/09	4.773	2040	121,355	122,260
Issue of 2009, Series B	06/02/09	4.563	2025	172,125	172,125
Issue of 2010, Series A	06/02/10	3.898	2041	616,000	616,000
Issue of 2010, Series B	06/02/10	3.015	2023	50,800	51,030
Issue of 2010, Series C	08/25/10	2.188	2028	139,775	139,775
Issue of 2010, Series D	12/02/10	4.342	2046	760,200	760,200
Issue of 2011, Series A	06/30/11	2.715	2023	694,130	694,130
Total principal amount				6,302,880	6,365,037
Revenue certificates				200,000	200,000
Unamortized premiums, discounts, and debt-related costs (including net loss on refundings), net				98,171	111,562
Debt due within one year (including current portion of variable rate debt)				(246,582)	(178,885)
				$ 6,354,469	6,497,714

Revenue bonds generally are callable 10 years after issuance. The Department has agreed to certain covenants with respect to bonded indebtedness. Significant covenants include the requirement that the Power Systems' net income, as defined, will be sufficient to pay certain amounts of future annual bond interest and of future annual aggregate bond interest and principal maturities. Revenue bonds and refunding bonds are collateralized by the future revenues of the Power System.

(a) Long-Term Debt Activity

The Power System had the following activity in long-term debt for the fiscal years ended June 30, 2012 and 2011 (amounts in thousands):

		Balance, July 1, 2011	Additions	Reductions	Balance, June 30, 2012	Current portion
Long-term debt:						
Bonds	$	6,476,599	—	(75,549)	6,401,050	226,582
Revenue certificates		200,000	—	—	200,000	20,000
Total	$	6,676,599	—	(75,549)	6,601,050	246,582

		Balance, July 1, 2010	Additions	Reductions	Balance, June 30, 2011	Current portion
Long-term debt:						
Bonds	$	5,751,444	1,684,277	(959,122)	6,476,599	158,885
Revenue certificates		200,000	—	—	200,000	20,000
Total	$	5,951,444	1,684,277	(959,122)	6,676,599	178,885

(b) New Issuances

Fiscal Year 2012

The Power System did not issue any new money or refunding Power System Revenue Bonds for fiscal year 2012.

Fiscal Year 2011

In August 2010, the Power System issued $139.8 million of Power System Revenue Bonds, 2010 Series C. The net proceeds of $138.7 million, net of $1.1 million cost of issuance and underwriter's discount, were deposited into the construction fund to be used for renewable energy projects. The Power 2010 Series C Bonds, designated as direct payment new Clean Renewable Energy Bonds (CREBs) and Qualified Energy Conservation Bonds (QECBs), enabled the Department to receive subsidy payments from the U.S. Treasury equal to 3.37% representing 70.00% of the tax credit rate of 4.81% (the credit rate determined under Section 54(A)(b)(3) of the Internal Revenue Code of 1986). The financing provided a weighted average life of 16.9 years, an average coupon rate of 5.52% and an effective interest rate of 2.21% (net of the tax subsidy). The Power System received subsidy payments totaling $250,563 for the CREBs and $3,749,727 for the QECBs during the fiscal year ended June 30, 2011. These subsidies are recorded as federal bond subsidies on the Statements of Revenue, Expenses, and Changes in Fund Net Assets.

In December 2010, the Power System issued $760.2 million of Power System Revenue Bonds, 2010 Series D. The net proceeds of $755.7 million (net of underwriter's discount of $4.5 million) were deposited into the construction fund to be used for capital improvements.

Lastly, in June 2011, the Power System issued $694.13 million of Power System Revenue Bonds, 2011 Series A, the proceeds of which were used to refund $765.55 million of Power System Revenue Bonds, 2001 Series A, SubSeries A-1 and A-2 and $60.87 million of Power System Revenue Bonds, 2003 Series B. In addition to bond proceeds, the Department contributed $50 million to the financing. The refinancing resulted in $102.1 million in net present value savings (excluding Department contribution) over the next five years and a net loss for accounting purposes of $12.6 million, which was deferred and is being amortized over the life of the new bonds.

(c) Outstanding Debt Defeased

The Power System defeased certain revenue bonds in prior years by placing cash or the proceeds of new revenue bonds in irrevocable trusts to provide for all future debt service payments on the old bonds. Accordingly, the trust account assets and the liability for the defeased bonds are not included in the Power System's financial statements.

At June 30, 2012, the following revenue bonds outstanding are considered defeased (amounts in thousands):

Bond issues		Principal outstanding
Second issue of 1993	$	7,500
Refunding issue of 1994		18,065
Issue of 1994		5,020
	$	30,585

(d) Variable Rate Bonds

As of June 30, 2012 and 2011, the Power System had $969.3 million in variable rate bonds. The variable rate bonds currently bear interest at weekly and daily rates ranging from 0.15% to 0.17% as of June 30, 2012 and 0.05% to 0.06% as of June 30, 2011. The Power System can elect to change the interest rate period of the bonds with certain limitations. The bondholders have the right to tender the bonds to the tender agent on any business day with seven days' prior notice. The Power System has entered into standby and line of credit agreements with a syndicate of commercial banks in an initial amount of $580.8 million and $388.5 million to provide liquidity for the variable rate bonds. The extended standby agreements expire in January 2015 for the $580.8 million and in June 2014 for the $388.5 million.

Under the agreements, the $580.8 million variable rate bonds will bear interest that is payable quarterly at the greatest of: (a) the Prime Rate plus 1.00% (b) the Federal Funds Rate plus 2.00% and (c) 7.50%, while the $388.5 million variable rate bonds will bear interest that is payable quarterly at the greatest of: (a) the Prime Rate plus 2.00%; (b) the Federal Funds Rate plus 2.00%; (c) the Daily

One-Month LIBOR plus 0.5%; and (d) 7.50%. The unpaid principal of each liquidity advance made by the liquidity provider is payable in ten equal semi-annual installments ninety days immediately following the related liquidity advance. At its discretion, the Power System has the ability to convert the outstanding bonds to fixed rate obligations, which cannot be tendered by the bondholders.

The variable rate bonds have been classified as long-term on the balance sheets as the liquidity facilities give the Power System the ability to refinance on a long-term basis and the Power System intends to either renew the facility or exercise its right to tender the debt as a long-term financing. The portion that would be due in the next fiscal year in the event that the outstanding variable rate bonds were tendered and purchased by the commercial banks under the standby agreements has been included in the current portion of long-term debt and was $96.9 million at both June 30, 2012 and 2011.

(e) Revenue Certificates

As of June 30, 2012 and 2011, the Power System has outstanding $200 million of commercial paper bearing interest at an average rate of 0.19%. The commercial paper matures not more than 270 days from the date of issuance.

The Department entered into a letter of credit and reimbursement agreement (the Agreement) with a commercial bank in the amount of $200 million to provide liquidity and credit support for the Department’s commercial paper program. The agreement secures the payment when due of the principal and interest on commercial paper issued on or after August 27, 2010. Drawings on the agreement will represent advances to the Department and will bear interest that is payable monthly at the highest of (i) the Prime Rate plus 1.00%, (ii) Federal Funds Rate plus 2.00%, (iii) the Daily One-Month LIBOR plus 3.00%, and (iv) 7.00%. The unpaid principal of each advance is payable in ten equal semiannual installments, commencing on the date six months after the advance. The Agreement terminates on August 26, 2013.

The revenue certificates have been classified as long-term debt on the balance sheets as the Agreement gives the Power System the ability to refinance on a long-term basis and the Power System intends to either renew the Agreement or exercise its option to draw on the Agreement. The portion that would be due in the next fiscal year in the event that the outstanding revenue certificates were advanced by the commercial bank under the Agreement has been included in the current portion of long-term debt and was $20 million at both June 30, 2012 and 2011.

(f) Scheduled Principal Maturities and Interest

Scheduled annual principal maturities and interest are as follows (amounts in thousands):

		Principal	Interest and amortization
Fiscal year(s) ending June 30:			
2013	$	129,651	293,596
2014		131,575	289,208
2015		142,578	283,579
2016		145,865	277,503
2017		149,235	271,543
2018 – 2022		809,930	1,267,252
2023 – 2027		986,947	1,079,650
2028 – 2032		1,109,184	821,078
2033 – 2037		1,100,130	580,834
2038 – 2042		976,645	318,356
2043 – 2047		621,140	63,479
Total requirements	$	6,302,880	5,546,078

Interest and amortization is net of $98.17 million of unamortized discount/premium and gain/loss due to issuances of new and refunding bonds.

The maturity schedule presented above reflects the scheduled debt service requirements for all of the Power System's long-term debt. The schedule is presented assuming that the tender options on the variable rate bonds, as discussed on the previous page, will not be exercised and that the full amount of the revenue certificates will be renewed. Should the bondholders exercise the tender options and the Power System convert all of the revenue certificates under the line of credit, the Power System would be required to redeem the $1,169.3 million in variable rate bonds outstanding over the next six years, as follows: $116.93 million in fiscal year 2013, $233.86 million in each of the fiscal years 2014 through 2017, and $116.93 million in fiscal year 2018. Accordingly, the balance sheets recognize the possibility of the exercise of the tender options and reflect the $116.93 million that could be due in fiscal year 2013 as a current portion of long-term debt payable. Interest and amortization include interest requirements for variable rate bonds, using the variable debt interest rate in effect at June 30, 2012 of 0.144%.

(11) Retirement, Disability, and Death Benefit Insurance Plan

The Department has a funded contributory retirement, disability, and death benefit insurance plan covering substantially all of its employees. The Water and Power Employees' Retirement, Disability, and Death Benefit Insurance Plan (the Plan) operates as a single-employer defined benefit plan to provide pension benefits to eligible department employees and to provide disability and death benefits from the respective insurance funds. Plan benefits are generally based on years of service, age at retirement, and the employee's highest 12 consecutive months of salary before retirement. Active participants who joined the

Plan on or after June 1, 1984 are required to contribute 6% of their annual covered payroll. Participants who joined the Plan prior to June 1, 1984 contribute an amount based upon an entry-age percentage rate. The Department contributes $1.10 for each $1.00 contributed by participants plus an actuarially determined annual required contribution (ARC) as determined by the Plan's independent actuary, taking into consideration the amount of net pension asset or obligation currently recorded on the balance sheet. The required contributions are allocated between the Power System and the Water System based on the current year labor costs.

The Retirement Board of Administration (the Retirement Board) is the administrator of the Plan. The Plan is subject to provisions of the Charter of the City and the regulations and instructions of the Board. The Plan is an independent pension trust fund of the City.

Plan amendments must be approved by both the Retirement Board and the Board. The Plan issues separately available financial statements on an annual basis. Such financial statements can be obtained from the Department of Water and Power Retirement Office, 111 N. Hope, Room 357, Los Angeles, California 90012.

The annual pension cost (APC) and net pension asset for the Department's Plan consist of the following (amounts in thousands):

		Year ended June 30	
		2012	**2011**
Annual required contribution	$	363,886	329,178
Interest on net pension asset		(8,719)	(10,409)
Adjustment to annual required contribution		13,211	15,772
APC (including $127.8 million and $106.5 million of amounts capitalized in fiscal years 2012 and 2011, respectively)		368,378	334,541
Department contributions		(326,200)	(282,377)
Change in net pension asset		42,178	52,164
Net pension asset at beginning of year		(52,102)	(104,266)
Net pension asset at end of year	$	(9,924)	(52,102)

The Power System's allocated share of the Plan's APC and net pension asset consists of the following (amounts in thousands):

		Year ended June 30	
		2012	2011
Annual required contribution	$	247,443	223,841
Interest on net pension asset		(5,929)	(7,078)
Adjustment to annual required contribution		8,983	10,725
APC (including $78.7 million and $62.7 million of amounts capitalized in fiscal years 2012 and 2011, respectively)		250,497	227,488
Power System contributions		(217,902)	(188,544)
Change in net pension asset		32,595	38,944
Net pension asset at beginning of year		(14,386)	(53,330)
Net pension liability (asset) at end of year	$	18,209	(14,386)

ARCs are determined through actuarial valuations using the entry-age normal actuarial cost method. The actuarial value of assets in excess of the Department's Actuarial Accrued Liability (AAL) is being amortized by level contribution offsets over rolling 15-year periods effective July 1, 2000.

In accordance with actuarial valuations, the Department's required contribution rates are as follows:

Fiscal year	Normal cost	Deficit amortization	Contribution rate
2012	15.08%	25.18%	41.82%
2011	14.68	22.34	38.45

The significant actuarial assumptions include an investment rate of return of 7.75%, projected inflation adjusted salary increases of 4.25%, and cost-of-living increases of 3.00%. The actuarial value of assets is determined using techniques that smoothen the effects of short-term volatility in the market value of investments over a five-year period. Plan assets consist primarily of corporate and government bonds, common stocks, mortgage-backed securities, and short-term investments.

(Continued)

Trend information for fiscal years 2012, 2011, and 2010 for the Power System is as follows (amounts in thousands):

Year ended June 30		Net pension liability (asset)	Percentage of APC contributed		APC
2012	$	18,209	87%	$	250,497
2011		(14,386)	83		227,488
2010		(53,330)	88		146,735

(a) Disability and Death Benefits

The Power System's allocated share of disability and death benefit plan costs and administrative expenses totaled $20 million and $13 million for fiscal years 2012 and 2011, respectively.

(b) Funded Status and Funding Progress Based on Latest Actuarial Study

On September 18, 2012, the latest actuarial study as of July 1, 2012 was completed for the Department for fiscal 2013. As of July 1, 2012, the Department's actuarial value of assets was $7.57 billion and AAL for benefits was $9.69 billion, resulting in an Unfunded Actuarial Accrued Liability (UAAL) of $2.12 billion. The covered payroll (annual payroll of active employees covered by the Plan) was $887 million, and the ratio of the UAAL to the covered payroll was 239%.

As of July 1, 2011, the Department's actuarial value of assets was $7.5 billion and AAL for benefits was $9.3 billion, resulting in a UAAL of $1.8 billion. The covered payroll (annual payroll of active employees covered by the Plan) was $870.2 million, and the ratio of the UAAL to the covered payroll was 211%.

As of July 1, 2010, the Department's actuarial value of assets was $7.2 billion and AAL for benefits was $8.9 billion, resulting in a UAAL of $1.7 billion. The covered payroll (annual payroll of active employees covered by the Plan) was $856.1 million, and the ratio of the UAAL to the covered payroll was 193%.

Actuarial valuations of an ongoing plan involve estimates of the value of reported amounts and assumptions about the probability of occurrence of events far into the future. Examples include assumptions about future employment, mortality, and the salary increases. Amounts determined regarding the funded status of the Plan and the ARCs of the Department are subject to continual revision as actual results are compared with past expectations and new estimates are made for the future. The schedule of funding progress, presented as required supplementary information, presents information about whether the actuarial value of plan assets is increasing or decreasing over time relative to the AAL for benefits.

(12) Other Postemployment Benefit (Healthcare) Plan

(a) Plan Description

The Department provides certain other postemployment benefits (OPEB), such as medical and dental plans, to active and retired employees and their dependents. The healthcare plan is administered by the Department. The Retirement Board and the Board have the authority to approve provisions and obligations. Eligibility for benefits for retired employees is dependent on a combination of age and service of the participants pursuant to a predetermined formula. Any changes to these provisions must be approved by the Retirement Board and the Board. The total number of active and retired Department participants entitled to receive benefits was approximately 16,340 and 16,758 for the fiscal years ended June 30, 2012 and 2011, respectively.

The health plan is a single-employer defined benefit plan. During fiscal year 2007, the Retiree Health Benefits Fund (the Fund) was created to fund the postemployment benefits of the Department. The Fund is administered as a trust and has its own financial statements. Such financial statements can be obtained from the Department of Water and Power Retirement Office, 111 N Hope, Room 357, Los Angeles, California 90012.

(b) Funding Policy

The Department pays a monthly maximum subsidy of $1,518 for medical and dental premiums depending on the employee's work location and benefits earned. Participants choosing plans with a cost in excess of the subsidy they are entitled to are required to pay the difference.

Although no formal funding policy has been established for the future benefits to be provided under this plan, the Department has made significant contributions into the Fund. In fiscal year 2012, the Department transferred $37.5 million into the Fund and paid an additional $64.1 million in retiree medical premiums. In fiscal year 2011, the Department transferred $75 million in cash into the Fund and paid an additional $65.6 million in retiree medical premiums. The Power System's portion of these amounts was $69.1 million and $95.6 million for 2012 and 2011, respectively.

(c) Annual OPEB Cost and Net OPEB Obligation

The annual OPEB cost (expense) is calculated based on the employer ARC, an amount actuarially determined in accordance with the parameters of GASB Statement No. 45, *Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions*. The ARC represents a level of funding that, if paid on an ongoing basis, is projected to cover normal cost under each year and amortize any unfunded actuarial liabilities (or funding excess) over a period not to exceed 30 years.

The following table shows the components of the Department's annual OPEB cost for the year, the amount actually contributed to the Plan, and changes in the net OPEB asset (amounts in thousands):

		Year ended June 30	
		2012	**2011**
Annual required contribution	$	53,691	68,705
Interest on net OPEB asset		(69,046)	(62,322)
Adjustment to annual required contribution		56,975	50,081
Annual OPEB costs		41,620	56,464
Contributions made		(101,610)	(140,590)
Change in net OPEB asset		(59,990)	(84,126)
Net OPEB asset – beginning of year		(863,884)	(779,758)
Net OPEB asset – end of year	$	(923,874)	(863,884)

The following table shows the components of the Power System's share in annual OPEB cost for the year, the amount actually contributed to the Plan, and changes in the net OPEB asset (amounts in thousands):

		Year ended June 30	
		2012	**2011**
Annual required contribution	$	36,510	46,720
Interest on net OPEB asset		(46,952)	(42,379)
Adjustment to annual required contribution		38,743	34,054
Annual OPEB costs		28,301	38,395
Contributions made		(69,094)	(95,609)
Change in net OPEB asset		(40,793)	(57,214)
Net OPEB asset – beginning of year		(590,686)	(533,472)
Net OPEB asset – end of year	$	(631,479)	(590,686)

The Department's annual OPEB cost, the percentage of ARC contributed to the Plan, and the net postemployment asset for fiscal years 2012, 2011, and 2010 were as follows (amounts in thousands):

		2012	2011	2010
Annual OPEB cost	$	41,620	56,464	46,400
Percentage of OPEB costs contributed		244%	249%	346%
Net postemployment asset at end of year	$	923,874	863,884	779,758

The Power System's share in the annual OPEB cost, the percentage of ARC contributed to the Plan, and the net retirement asset for fiscal years 2012, 2011, and 2010 were as follows (amounts in thousands):

		2012	2011	2010
Annual OPEB cost	$	28,301	38,395	31,552
Percentage of OPEB costs contributed		244%	249%	346%
Net postemployment asset at end of year	$	631,479	590,686	533,472

(d) Funded Status and Funding Progress Based on Latest Actuarial Study

On September 18, 2012, the latest actuarial study as of July 1, 2012 was completed for fiscal 2013. As of July 1, 2012, the Department's actuarial value of assets was $1.25 billion and AAL for benefits was $1.57 billion, resulting in a UAAL of $0.32 billion. The covered payroll (annual payroll of active employees covered by the Plan) was $887 million, and the ratio of the UAAL to the covered payroll was 36%.

As of July 1, 2011, the Department's actuarial value of assets was $1.1 billion, and AAL for benefits was $1.6 billion, resulting in a UAAL of $418 million. The covered payroll (annual payroll of active employees covered by the Plan) was $870 million, and the ratio of the UAAL to the covered payroll was 73%.

As of July 1, 2010, the Department's actuarial value of assets was $987 million, and AAL for benefits was $1.6 billion, resulting in a UAAL of $644 million. The covered payroll (annual payroll of active employees covered by the Plan) was $856 million, and the ratio of the UAAL to the covered payroll was 75%.

Actuarial valuations of an ongoing plan involve estimates of the value of reported amounts and assumptions about the probability of occurrence of events far into the future. Examples include assumptions about future employment, mortality, and the healthcare cost trend. Amounts determined regarding the funded status of the Plan and ARCs of the Department are subject to continual revision as actual results are compared with past expectations and new estimates are made for the future. The schedule of funding progress, presented as required supplementary information, presents information about whether the actuarial value of plan assets is increasing or decreasing over time relative to the AAL for benefits.

(e) Actuarial Methods and Assumptions

Projections of benefits for financial reporting purposes are based on the substantive plan (the plan understood by the Department and the plan members) and include the types of benefits provided at the time of each valuation and the historical pattern of sharing of benefit costs between the Department and the plan members to that point. The actuarial methods and assumptions used include techniques that are designed to reduce the effects of short-term volatility in AAL and the actuarial value of assets, consistent with the long-term perspective of the calculations.

In the July 1, 2011 actuarial valuation, the entry-age normal cost method was used. The actuarial assumptions include 7.75% discount rate, which represents the expected long-term return on plan assets, an annual healthcare cost trend rate of 9.00% initially, reduced by decrements to an ultimate rate of 5.00% over 10 years. Both rates include a 3.50% inflation assumption. The actuarial value of assets was determined using techniques that spread UAAL being amortized as a level percentage of projected payroll over a closed 24-year period.

In the July 1, 2010 actuarial valuation, the entry-age normal cost method was used. The actuarial assumptions include 7.75% discount rate, which represents the expected long-term return on plan assets, an annual healthcare cost trend rate of 10.00% initially, reduced by decrements to an ultimate rate of 5.00% over 10 years. Both rates include a 3.75% inflation assumption. The actuarial value of assets was determined using techniques that spread UAAL being amortized as a level percentage of projected payroll over a closed 25-year period.

(f) Healthcare Reform Legislation

The Patient Protection and Affordable Care Act (PPACA) was signed into law on March 23, 2010. One key provision of the PPACA is the assessment of the excise tax on high cost plans (Cadillac Plans) beginning in 2018. Under this act, a 40% excise tax applies to plans with costs exceeding certain annual thresholds ($11,850 for single; $30,950 for families for early retirees). Significant uncertainties exist regarding the impact of the excise tax on high cost plans without further regulatory guidance. Management estimated the potential impact of this tax on the liability is based on unadjusted thresholds and assuming the tax is shared between the Department and its participants in the same way that the current costs are shared. The estimated impact of the 40% excise tax provision on high cost plans beginning in 2018, under the healthcare reform, is reflected in the actuarial report as July 1, 2010 and going forward.

(13) Other Long-Term Liabilities

(a) Other Long-Term Liabilities

The Power System has the following other long-term liabilities:

		Balance July 1, 2011	Additions	Reductions	Balance June 30, 2012	Current portion
Accrued liabilities	$	10,487	—	(1,720)	8,767	—
Deferred credits:						
Purchased power	$	140,995		(95,830)	45,165	21,100
Rate stabilization		75,000	38,000	—	113,000	—
Other		2,995		(184)	2,811	—
	$	218,990	38,000	(96,014)	160,976	21,100
Accrued workers' compensation claims	$	40,300	—	3,175	43,475	—
Derivative instrument liabilities	$	73,770	17,526	—	91,296	—

		Balance July 1, 2010	Additions	Reductions	Balance June 30, 2011	Current portion
Accrued liabilities	$	12,040	—	(1,553)	10,487	—
Deferred credits:						
Purchased power	$	234,569	—	(93,574)	140,995	95,830
Rate stabilization		75,000	—	—	75,000	—
Other		2,223	772	—	2,995	—
	$	311,792	772	(93,574)	218,990	95,830
Accrued workers' compensation claims	$	40,692	—	(392)	40,300	—
Derivative instrument liabilities	$	84,268	—	(10,498)	73,770	—

(b) Deferred Credits

The Department has deferred credits that are related to revenues collected from customers, but have not been earned. These funds are deferred and recognized as costs related to these deferrals are incurred.

Purchased Power Deferrals

During fiscal year 2006, the Board approved the suspension of deferring precollected purchased power costs and the reversal of the precollected purchased power costs recorded in prior years. The amount reversed is the cost of energy from IPP less the amount designated in rates for out-of-market purchased power costs. The reversal of the deferred credit is credited to retail sales. During fiscal years 2012 and 2011, the Power System reversed $95.8 million and $93.6 million, respectively, related to precollected purchase power costs. At June 30, 2012 and 2011, $45.1 million and $140.9 million, respectively, remain as part of deferred credits related to precollected purchased power costs.

Rate Stabilization Account

In April 2008, the City Council approved an amendment to the electric rate ordinance, which required the balance of the Rate Stabilization Account to be maintained separately from the Energy Cost Adjustment Account. The ordinance also directed that the deferred amount within the Energy Cost Adjustment Account be the beginning balance of the Rate Stabilization Account. During fiscal year 2012, $38 million was deferred from current year sales for resale. As of June 30, 2012 and 2011, the balance in the Rate Stabilization Fund, was $113 million and $75 million, respectively.

(c) Accrued Workers' Compensation Claims

Liabilities for unpaid workers' compensation claims are recorded at their present value when they are probable of occurrence and the amount can be reasonably estimated. The liability is actuarially determined, based on an estimate of the present value of the claims outstanding and an amount for claim events incurred but not reported based upon the Department's loss experience, less the amount of claims and settlements paid to date. The discount rate used to calculate this liability at its present value was 4% at June 30, 2012 and 2011. The Department has third-party insurance coverage for workers' compensation claims in excess of $1 million.

Overall indicated reserves for workers' compensation claims, for both the Water System and the Power System, undiscounted, have increased from $69 million as of June 30, 2011 to $74 million as of June 30, 2012. The increase is mainly attributable to a increase in the number of cases filed at the Department. Workers' compensation claims typically take longer than one year to settle and close out. The entire discounted liability is shown as long-term on the balance sheets as of June 30, 2012 and 2011.

Changes in the Department's undiscounted liability since June 30, 2010 are summarized as follows (amounts in thousands):

		June 30		
		2012	2011	2010
Balance at beginning of year	$	69,155	69,692	53,037
Current year claims and changes in estimates		26,769	19,541	34,771
Payments applied		(21,624)	(20,078)	(18,116)
Balance at end of year	$	74,300	69,155	69,692

The Power System's portion of the discounted reserves as of June 30, 2012 and 2011 is $43.5 million and $40.3 million, respectively.

(14) Commitments and Contingencies

(a) Transfers to the Reserve Fund of the City of Los Angeles

Under the provisions of the City Charter, the Power System transfers funds at its discretion to the reserve fund of the City. Pursuant to covenants contained in the bond indentures, the transfers may not be in excess of the increase in fund net assets before transfers to the reserve fund of the City of the prior fiscal year. Such payments are not in lieu of taxes and are recorded as a transfer in the statements of revenues, expenses, and changes in fund net assets.

The Department authorized total transfers of $250 million and $259 million in fiscal years 2012 and 2011, respectively, from the Power System to the reserve fund of the City.

(b) Palo Verde Nuclear Generating Station (PVNGS) Matters

As a joint project participant in PVNGS, the Department has certain commitments with respect to nuclear spent fuel and waste disposal. Under the Nuclear Policy Act, the Department of Energy (the DOE) is to develop facilities necessary for the storage and disposal of spent fuel and to have the first such facility in operation by 1998; however, the development of the repository designated at Yucca Mountain in the state of Nevada was postponed indefinitely for political reasons after DOE spent some billions of dollars conducting feasibility studies. A Blue Ribbon Committee was formed by the federal government to look at other alternatives for nuclear waste disposal, but thus far, it still has not come up with any solutions.

Capacity in existing fuel storage pools at PVNGS was exhausted in 2003. A Dry Cask Storage Facility (also called the Independent Spent Fuel Storage Facility) was built and completed in 2003 at a total cost of $33.9 million (about $3.3 million for the Department). The facility has the capacity to store all the spent fuel generated by the plant until the end of its life in 2027. With the current operating license extension granted by the Nuclear Regulatory Commission, PVNGS is allowed to operate until 2047. The Dry Cask Storage Facility will be expanded as needed to accommodate additional spent fuel until it is removed by DOE.

The Department accrues for current nuclear fuel storage costs as a component of fuel expense as the fuel is burned. The Department's share of spent nuclear fuel costs related to its indirect interest in PVNGS is included in purchased power expense.

Because of the DOE's inability to provide a disposal site, the PVNGS operating agent filed damages actions against the DOE to recover costs incurred by the PVNGS participants. A settlement was reached in August 2010 in the amount of $30.2 million from DOE of which $1.7 million is the Department's share of the settlement which covers costs incurred up to 2006. Additional cost recovery is being pursued for the period post 2006.

The Price Anderson Act (the Act) requires that all utilities with nuclear generating facilities share in payment for claims resulting from a nuclear incident. Participants in PVNGS currently insure potential claims and liability through commercial insurance with a $375 million limit; the remainder of the potential liability is covered by the industrywide retrospective assessment program provided under the Act. This program limits assessments to a maximum of $118 million for each licensee for each nuclear incident occurring at any nuclear reactor in the United States; payments under the program are limited to $18 million per incident, per year. Based on the Department's 5.70% direct interest and its 3.96% indirect investment interest through SCPPA, the Department would be responsible for a maximum assessment of $11 million per incident, limited to payments of $2 million per incident annually.

The NRC guidelines require improved security in immediate areas surrounding the reactor buildings. PVNGS enlarged the protected area with inclusion of an outage support facility, a new warehouse, a minor vehicle maintenance facility, and a fuel depot to reduce vehicular traffic in and out of the protected area. The estimated cost for these facilities is approximately $6.3 million to the Department.

In response to the nuclear event in Fukushima, Japan, the NRC may require PVNGS to increase the redundancy in its power supply to emergency cooling systems and accelerate the transfer of spent fuel from the pool to the dry cask storage. The Department cannot predict what new requirements will be mandated by the NRC and the resulting costs to the Department.

(c) Environmental Matters

Numerous environmental laws and regulations affect the Power System's facilities and operations. The Department monitors its compliance with laws and regulations and reviews its remediation obligations on an ongoing basis. The following topics highlight some of the major environmental compliance issues affecting the Power System:

Air Quality – Nitrogen Oxide (NOx) Emissions

The Power System's generating station facilities are subject to the Regional Clean Air Incentives Market (RECLAIM) NOx emission reduction program adopted by the South Coast Air Quality Management District (SCAQMD). In accordance with this program, SCAQMD established annual NOx allocations for NOx RECLAIM facilities based on historical emissions and type of emission sources operated. These allocations are in the form of RECLAIM trading emission credits (RTCs).

Facilities that exceed their allocations may buy RTCs from other companies that have emissions below their allocations. The Department has a program of installing emission controls and purchasing RTCs, as necessary, to meet its emission requirements.

As a result of the installation of NOx control equipment and the repowering of existing units, the Department has sufficient RTCs to meet its native load requirements for normal operations.

Air Quality – Greenhouse Gas Emissions

In September 2006, the state of California adopted two new laws designed to reduce greenhouse gas (GHG) emissions in California. The first, Assembly Bill 32, the California Global Warming Solutions Act of 2006, requires the California Air Resources Board (ARB) to develop regulations to reduce statewide GHG emissions back to 1990 levels by 2020. In 2007, the ARB established California's 1990 GHG emissions baseline, and developed a mandatory reporting regulation to require California sources to report their GHG emissions annually starting with 2008 data. In December 2008, the ARB adopted a Climate Change Scoping Plan which identifies nearly 70 potential strategies and measures to achieve the state's GHG emissions reduction goal. Subsequently, the ARB adopted regulations to implement a number of the emission reduction measures identified in the Scoping Plan.

The Scoping Plan includes the following emission reduction measures applicable to the electricity sector: 1) increase renewable energy to 33%, 2) expand energy efficiency programs, 3) reduce SF6 emissions from gas insulated electrical switchgear, and 4) establish a GHG cap-and-trade program. The cap-and-trade program sets a statewide cap on GHG emissions beginning in January 2013, with the cap declining two to three percent per year from 2013 to 2020. The cap-and-trade program covers GHG emissions from all electricity generated in California or imported from other states, in-state industrial and manufacturing facilities, as well as natural gas and transportation fuels consumed in California.

The second bill adopted by the state of California is designed to reduce greenhouse gas emissions from the generation of electricity consumed in California. Senate Bill 1368 requires the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) to establish a greenhouse gas emissions performance standard and implement regulations governing long-term financial commitments in base load generation made by load serving entities (LSEs) including publicly-owned electric utilities (POUs). These regulations are intended to prohibit any California LSE from entering into or renewing a long-term financial commitment with a base load generating resource that exceeds the greenhouse gas emissions performance standard, currently set at 1,100 pounds carbon dioxide per megawatt hour of electricity generated. This means that when existing contracts with high-emitting generating resources expire, those resources will be replaced by lower emitting generating resources that comply with the greenhouse gas emissions performance standard.

At the federal level, several legislative bills have been proposed or introduced, but none have passed Congress. As such, a federal cap-and-trade program is unlikely to be established in the same time frame (2012) as a state cap-and-trade program, but may be considered in future years. However, the United States Environmental Protection Agency (EPA) adopted its Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule in June 2010. The Power System's

(Continued)

in-basin repowering projects requiring PSD permits after January 2, 2011 would be impacted as they would be required to submit a GHG Best Available Control Technology (BACT) analysis. EPA is expected to issue its GHG BACT guidance for public review later this year. Also, the Power System's generating stations will need to amend their Title V operating permits to incorporate any GHG requirements when the permits are renewed.

EPA Coal Combustion Residuals Proposed Rules

On June 21, 2010, the US Environmental Protection Agency (EPA) proposed to establish federal standards to regulate coal combustion residuals (coal ash). The two options being considered are to designate coal ash as either hazardous or non-hazardous. The hazardous waste proposal would phase out the disposal of ash in wet storage ponds. The nonhazardous designation would set federal guidelines for state disposal that require the installation of additional liners on new wet storage pond. Both options set new requirements for storing and monitoring the waste in dry landfills.

The worst case scenario impact at the Intermountain Power Plant would be $483 million in capital cost plus $110 million in annual operating cost for the hazardous option if the existing landfill has to be removed and coal ash has to be disposed of at an offsite facility. For the nonhazardous option, the impact would be $62 million in capital cost plus $2 million in annual operating cost.

For Mohave Power Plant, the worst case scenario impact would be $230 million in capital cost for the hazardous option if the existing landfill has to be removed and disposed of at an offsite facility. For the nonhazardous option, the impact would be $6 million in capital cost plus $0.25 million in annual operating cost.

For the above facilities, the costs translate into electric rate impacts of about 1.4 percent for the hazardous option and 0.18 percent for the nonhazardous option.

At this time, the EPA is still analyzing over half a million comments received following the rule proposal. The EPA is also gathering additional data prior to finalizing the rules and the time frame is still unknown at the present time.

Power Plant Once-Through Cooling Water Systems

Once-through cooling (OTC) is the process where water is drawn from a source, pumped through equipment to provide cooling, and then discharged. Some type of cooling process is necessary for nearly every type of traditional electrical generating station, and the OTC process is utilized by many electrical generating stations located next to large bodies of water. Typically, the water used for cooling is not chemically changed in the process although its temperature is increased.

Due to the Second Circuit Court's decision to remand most of Environmental Protection Agency (EPA's) 316(b) Rule finalized in July 2004, EPA suspended this Rule and is in the process of drafting a new rule. EPA's proposed new rule for existing facilities was released in the federal register for comments on April 20, 2011 for a 120-day comments period, The newly proposed rule requirements applies to cooling water intake structures for all existing power generating facilities that withdraw more than 2 million gallons per day of water from waters of the United States and use at least 25% of the water they withdraw exclusively for cooling purposes. Under this proposed rule, an owner or operator of an existing facility would be able to choose one of two compliance options for impingement mortality (IM): (1) monitoring to demonstrate that specified performance standards for impingement mortality of fish and shellfish have been met or (2) demonstrate that intake velocity meets specified design criteria. IM compliance must be met 8 years after the effective date of the Rule. For entrainment mortality, the proposed rule requires entrainment studies and allows for compliance on a site specific basis. As part of a settlement agreement, a final rule had to be issued by July 2012; however, on July 17, 2012, the parties to the underlying litigation signed a modified settlement agreement, which extends the deadline for the Final Rule to June 27, 2013. The language for the Final Rule is still subject to change. On June 11, 2012, the EPA published a Notice of Data Availability (NODA), for a 30-day comment period, that would allow relief to the IM compliance. The Department will need an exemption or some relief from the eight year IM compliance date. In addition, on June 12, 2012, the EPA published a second NODA regarding the willingness to pay for quantifying the non-use benefits of reducing impingement and entrainment. The Department is evaluating the potential impacts of the proposed rule on its facilities.

In the absence of EPA's 316(b) Rule, the California State Water Resources Control Board (State Board) decided to move forward and adopted their own Statewide 316 b Policy (Policy) on May 4, 2010. The Policy became effective on October 1, 2010. This policy requires the Department's coastal power plants to reduce OTC by 93% – equivalent to wet cooling towers using seawater. This is referred to as the Track 1 compliance path. If the Track 1 compliance path is found to be infeasible, with concurrence from the State Board, a Track 2 compliance path can be pursued, which requires that the cooling water intake structure (CWIS) achieve an impingement mortality and entrainment (IM/E) reduction level of 90% of the Track 1 compliance standard or 83.7% on a unit-by-unit basis. The Department has made a decision to pursue the Track 1 compliance path, in order to comply with the Policy and completely eliminate the use of OTC. Recently, the Department was successful in having the Policy amended to extend the compliance dates, for six out of the nine remaining OTC units, to 2024 for Scattergood, and 2029 for Haynes and Harbor. The other four OTC units are on schedule, due to an AQMD settlement, to be repowered with eliminating OTC by 2013 and 2015, respectively. The Amendment to the Policy was adopted on July 19, 2011. The Amendment requires the Department to submit additional information responsive to the Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) resolution by December 31, 2012. Depending upon the information submitted by LADWP and no later than December 31, 2013, the State Board will consider modifications to the 2029 compliance dates. Furthermore, the Amendment requires implementation of interim measures, these measures include a proposal to study new and/or viable existing technologies to reduce impingement and entrainment. The proposal must be submitted to the State Board no later than December 31, 2015. Upon approval of the proposal, the interim measures must be in place no later than December 31, 2020. These interim measures will include the funding of a mitigation project or the use of screens or an equivalent alternative measure at each OTC unit or intake until the facility is in full compliance.

In addition, other regulatory changes have been made that could significantly impact operations at the Haynes and Harbor Generating Stations. The Regional Water Quality Control Board reclassified the body of water that the OTC water is discharged to an enclosed bay for the Harbor Generating Station, and sent a letter of intent to reclassify the receiving water body of water as an estuary for the Haynes Generating Station discharge. Even though the Haynes Generating Station will be repowering existing units, should there be a reclassification for the water body discharges at the Haynes Generating Station, there will be requirements that cannot be met with its existing cooling or future repowered configuration. The Department is in the process of reviewing the regulations and conducting studies. Once the studies are reviewed, the Department will determine an appropriate course of action.

Pollution and Remediation Obligations

The Department follows GASB Statement No. 49, *Accounting and Financial Reporting for Pollution and Remediation Obligations* (GASB No. 49). This statement addresses accounting and financial reporting standards for pollution (including contamination) remediation obligations, which are obligations to address the current or potential detrimental effects of existing pollution by participating in pollution remediation activities such as site assessments and cleanups. The scope of the statement excludes pollution prevention or control obligations with respect to current operations, and future pollution remediation activities that are required upon retirement of an asset, such as landfill closure and postclosure care and nuclear power plant decommissioning. The Power System's obligations were approximately $21 million as of June 30, 2012 and 2011.

(d) Litigation

i. Capital Facilities Fee Claims

In June 2007, the Department received a tentative decision in favor of the state and a number of local government agencies that are electric customers of the Department that claimed that the Department has rates that include a capital facilities' charge that violates the state's statute. However, in October 2008, the Department settled the case and recorded the $160 million settlement amount. Additionally, as permitted by SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, the Board approved to defer all potential costs associated with the resolution of this litigation and establish a corresponding long-term deferred debit to be recovered through future revenues over a period of up to 10 years, if necessary.

ii. Other

A number of claims and suits are also pending against the Department for alleged damages to persons and property and for other alleged liabilities arising out of its operations. In the opinion of management, any ultimate liability, which may arise from these actions, is not expected to materially impact the Power System's financial position, results of operations, or cash flows as of June 30, 2012.

(e) Risk Management

The Power System is subject to certain business risks common to the utility industry. The majority of these risks are mitigated by external insurance coverage obtained by the Power System. For other significant business risks, however, the Power System has elected to self-insure. Management believes that exposure to loss arising out of self-insured business risks will not materially impact the Power System's financial position, results of operations, or cash flows as of June 30, 2012.

(f) Credit Risk

Financial instruments, which potentially expose the Power System to concentrations of credit risk, consist primarily of retail and wholesale receivables. The Power System's retail customer base is concentrated among commercial, industrial, residential, and governmental customers located within the City. Although the Power System is directly affected by the City's economy, management does not believe significant credit risk exists at June 30, 2012, except as provided in the allowance for losses. The Power System manages its credit exposure by requiring credit enhancements from certain customers and through procedures designed to identify and monitor credit risk.

(g) Subsequent Events – Bond Sales

On October 4, 2012, the Power System issued $104.1 million of Power System Revenue Bonds, 2012 Series A. The net proceeds of $123.9 million (net of $19.8 million issue premium and underwriter's discount) were used to refund certain outstanding Power System Revenue Bonds, 2003 Series B amounting to $119.9 million which will be redeemed at a redemption price equal to 100 percent of the principal on July 1, 2013, and pay certain costs of issuance. The 2012 Series A Bonds have maturities ranging from 2014 through 2035 and those maturing on or after July 1, 2023 are subject to redemption prior to maturity at the option of the Department, as a whole or in part, on any date on or after July 1, 2022, at par. The financing provided an all-in true interest cost of 2.94% with an average life of 13.8 years. The refinancing resulted in $25.6 million net present value savings equivalent to 21.3% of the refunded bonds' par amount, and a net loss for accounting purposes of $4.8 million, which was deferred and is being amortized over the life of the new bonds.

On October 10, 2012, the Power System issued $350 million of Power System Revenue Bonds, 2012 Series B. The net proceeds of $398.6 million (net of $48.6 million issue premium and underwriter's discount) were deposited into the construction fund to be used to finance the budgeted Power System's Capital Improvement Program for Fiscal Year 2012-2013 and pay certain costs of issuance. The financing provided an all-in true interest cost of 4.16% with an average life of 28.6 years. The 2012 Series B Bonds have maturities ranging from 2038 through 2043 and all the bonds are optionally redeemable on or after July 1, 2022, at par.

Also, on October 11, 2012, the Power System issued $300 million of Power System Revenue Bonds, 2012 Series C. The net proceeds of $334.7 million (net of $34.7 million issue premium and underwriter's discount) were deposited into the construction fund to be used to finance the budgeted Power System's Capital Improvement Program for Fiscal Year 2012-2013 and pay certain costs of issuance. The financing provided an all-in true interest cost of 0.96% with an average life of 3.2 years. The 2012 Series C Bonds are optionally redeemable on or after October 1, 2015, at par.

(h) Subsequent Event – Rate Action

In October 2012, the Los Angeles City Council, approved two years of revenue increases for the Power System. System average rates will increase approximately 4.9% and 6% for fiscal years 2012-13 and 2013-14, respectively.

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Required Supplementary Information

(Unaudited)

June 30, 2012

Pension Plan – Schedule of Funding Progress

The following schedule provides information about the Department's overall progress made in accumulating sufficient assets to pay benefits when due, prior to allocations to the Water System and the Power System (amounts in thousands):

Actuarial valuation date July 1	Actuarial value of assets	Actuarial accrued liability (AAL)	Unfunded AAL (UAAL)	Funded ratio	Covered payroll	UAAL as a percentage of covered payroll
2012	$ 7,573,886	9,692,603	2,118,717	78%	$ 886,539	239%
2011	7,465,184	9,297,204	1,832,020	80	870,203	211
2010	7,244,430	8,893,618	1,649,189	81	856,090	193

Postemployment Healthcare Plan – Schedule of Funding Progress

The following schedule provides information about the Department's overall progress made in accumulating sufficient assets to pay benefits when due, prior to allocations to the Water System and the Power System (amounts in thousands):

Actuarial valuation date July 1	Actuarial value of assets	Actuarial accrued liability (AAL)	Unfunded AAL (UAAL)	Funded ratio	Covered payroll	UAAL as a percentage of covered payroll
2012	$ 1,244,039	1,566,059	322,020	79%	$ 886,539	36%
2011	1,132,929	1,550,896	417,967	73	870,203	48
2010	987,476	1,631,916	644,440	61	856,090	75

See accompanying independent auditors' report.