WE POWER SEATTLE

Seattle City Light

2014 Annual Report

Financial Information

FINANCIAL TABLE OF CONTENTS

AUDITED FINANCIAL STATEMENTS

SUPPLEMENTARY INFORMATION

Baker Tilly Virchow Krause, LLP
Ten Terrace Ct, PO Box 7398
Madison, WI 53707-7398
tel 608 249 6622
fax 608 249 8532
bakertilly.com

INDEPENDENT AUDITORS' REPORT

To the Energy Committee
The City of Seattle – City Light Department
Seattle, Washington

Report on the Financial Statements

We have audited the accompanying financial statements of The City of Seattle – City Light Department (the "Department"), an enterprise fund of The City of Seattle, Washington, as of and for the years ended December 31, 2014 and 2013, and the related notes to the financial statements, as listed in the table of contents.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

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. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Department's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Department's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Department as of December 31, 2014 and 2013, and the changes in its financial position and its cash flows thereof for the years then ended in accordance with accounting principles generally accepted in the United States of America.

To the Energy Committee
The City of Seattle – City Light Department

Emphasis of Matter

As discussed in Note 1, the financial statements present only the Department and do not purport to, and do not present fairly the financial position of The City of Seattle, Washington, as of December 31, 2014 and 2013 and the changes in its financial position and its cash flows thereof for the years then ended in accordance with accounting principles generally accepted in the United States of America. Our opinion is not modified with respect to this matter.

Other Matters

Required Supplementary Information
Accounting principles generally accepted in the United States of America require that the Management's Discussion and Analysis and Schedules of Funding Progress information as listed in the table of contents be presented to supplement the financial statements. Such information, although not a part of the financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the 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 financial statements, and other knowledge we obtained during our audit of the 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.

Other Information
Our audit was conducted for the purpose of forming an opinion on the financial statements as a whole. The Debt Service Coverage, Interest Requirements and Principal Redemption on Long-term Debt, Statement of Long-term Debt, Power Costs and Statistics, Historical Energy Resources, and Customer Statistics, which are the responsibility of management, are presented for purposes of additional analysis and are not a required part of the financial statements. Such information has not been subjected to the auditing procedures applied in the audit of the financial statements, and accordingly, we express no opinion or provide any assurance on it.

Baker Tilly Virchow Krause, LLP

Madison, Wisconsin
April 30, 2015

The following discussion and analysis of the financial performance of The City of Seattle—City Light Department (the Department) provides a summary of the financial activities for the years ended December 31, 2014, and 2013. This discussion and analysis should be read in combination with the Department's financial statements, which immediately follow this section.

ORGANIZATION

The Department is the public electric utility of The City of Seattle (the City). As an enterprise fund of the City, the Department owns and operates generating, transmission, and distribution facilities and delivers electricity to approximately 415,000 customers in Seattle and certain surrounding communities. The Department also provides electrical energy to other City agencies at rates prescribed by City ordinances.

OVERVIEW OF THE FINANCIAL STATEMENTS

The Department's accounting records are maintained in accordance with generally accepted accounting principles for proprietary funds as prescribed by the Governmental Accounting Standards Board (GASB). The Department's accounting records also follow the Uniform System of Accounts for Public Licensees prescribed by the Federal Energy Regulatory Commission (FERC).

This discussion and analysis is intended to serve as an introduction to the Department's financial statements, which are comprised of the financial statements and the notes to the financial statements and include the following:

Balance Sheets, Statements of Revenues, Expenses, and Changes in Net Position, and Statements of Cash Flows—The financial statements provide an indication of the Department's financial health. The balance sheets include all of the Department's assets, deferred outflows of resources, liabilities, deferred inflows of resources, and net position using the accrual basis of accounting, as well as an indication about which assets can be utilized for general purposes, and which assets are restricted as a result of bond covenants and other commitments. The statements of revenues, expenses, and changes in net position report all of the revenues and expenses during the time periods indicated. The statements of cash flows report the cash provided and used by operating activities, as well as other cash sources such as investment income and cash payments for bond principal and capital additions and betterments.

Notes to the Financial Statements—The notes to the financial statements provide additional information that is essential to a full understanding of the data provided in the financial statements.

CONDENSED BALANCE SHEETS

	December 31		
($ in millions)	2014	2013	2012[a]
Assets:			
Utility plant—net	$ 2,728.3	$ 2,541.1	$ 2,352.2
Restricted assets	298.4	227.0	275.7
Current assets	298.8	369.1	323.5
Other assets	319.7	301.0	278.9
Total assets	3,645.2	3,438.2	3,230.3
Total deferred outflows of resources	19.3	26.0	30.0
Total assets and deferred outflows of resources	3,664.5	3,464.2	3,260.3
Liabilities:			
Long-term debt	1,925.2	1,870.3	1,791.5
Noncurrent liabilities	67.3	78.1	74.8
Current liabilities	258.3	241.7	224.6
Other liabilities	26.7	19.2	15.4
Total liabilities	2,277.5	2,209.3	2,106.3
Total deferred inflows of resources	111.5	100.7	112.5
Net position:			
Net investment in capital assets	1,100.8	906.1	832.8
Restricted:			
Rate stabilization account	25.0	25.0	25.0
Special deposits and other purposes	-	(0.4)	0.7
Total restricted	25.0	24.6	25.7
Unrestricted—net	149.7	223.5	183.0
Total net position	1,275.5	1,154.2	1,041.5
Total liabilities, deferred inflows, and net position	$ 3,664.5	$ 3,464.2	$ 3,260.3

(a) GASB No. 65, *Items Previously Reported as Assets and Liabilities,* was implemented effective January 2013. Accordingly, the 2012 balance sheet was restated to conform to the 2013 presentation. See Note 1 Operations and Summary of Significant Accounting Policies.

ASSETS

Utility Plant—Net

2014 Compared to 2013

Utility plant assets net of accumulated depreciation and amortization increased $187.2 million to $2,728.3 million in 2014. Utility plant assets were comprised of hydroelectric production plant $763.6 million which increased $2.4 million, transmission plant $207.8 million which increased $5.9 million, distribution plant $2,194.2 million which increased $107.8 million, general plant $313.9 million which increased $8.7 million, and intangible assets $456.5 million which increased $15.9 million. The net increase in utility plant assets were partially offset by a $47.6 million increase in Accumulated depreciation and amortization to $1,611.5 million.

The $107.8 million increase in distribution plant is primarily due to $58.4 million for underground system, $14.2 million for overhead system, $13.3 million for transformers, $8.5 million for poles, $8.0 million for streetlights and $3.4 million for meters. In hydroelectric production, an increase of $22.8 million was due to continued improvements for generation units at the Boundary project which are expected to be completed in 2015. The additions to hydroelectric production were offset by retirements, primarily related to generation unit improvements.

Other components of utility plant include Construction work-in-progress $251.0 million which increased $86.9 million, Nonoperating property $10.5 million which increased $1.8 million, Assets held for future use $71.8 million which increased $3.1 million, and Land and land rights $70.5 million, which increased $2.3 million. The $86.9 million increase in Construction work-in-progress is primarily due to $13.1 million for the new customer billing system, $12.7 million for Boundary generation, $11.8 million for Denny Substation, and $49.3 million increases in various other projects, predominantly in distribution.

More information on the Department's capital assets can be found in Note 2 Utility Plant of the accompanying financial statements.

2013 Compared to 2012

Utility plant assets net of accumulated depreciation and amortization increased $188.9 million to $2,541.1 million in 2013. Utility plant assets were comprised of hydroelectric production plant $761.2 million which increased $46.5 million, transmission plant $201.8 million which increased $12.0 million, distribution plant $2,086.5 million which increased $119.5 million, general plant $305.2 million which decreased $5.2 million, and intangible assets $440.6 million which increased $29.0 million. The net increase in utility plant assets were partially offset by a $52.7 million increase in Accumulated depreciation and amortization.

The $119.5 million increase in distribution plant is primarily due to $62.1 million for underground system, $14.1 million for overhead system, $13.2 million for transformers, $11.5 million for poles, $8.6 million for streetlights and $6.3 million for substations. In hydroelectric production, an increase of $36.6 million was due to improvements to one of the generation units at the Boundary project; further improvements to additional units are ongoing and expected to continue through 2015.

Other components of utility plant include Construction work-in-progress $164.1 million which increased $31.7 million, Assets held for future use $68.7 million which increased $3.1 million, Nonoperating property

$8.7 million which increased $1.8 million, and Land and land rights $68.2 million, which increased $3.1 million. The $31.7 million increase in Construction work-in-progress is primarily due to $12.7 million for Boundary generation, $9.1 million for Denny Substation, and $7.1 million for Alaskan Way Viaduct. The $3.1 million increase in Assets held for future use included the addition of $11.3 million for preparation of the future Denny Substation site. This increase was partially offset by the write-off of previous costs for the Gorge second tunnel project and other assets which totaled $9.0 million.

Restricted Assets

2014 Compared to 2013

Restricted assets consisting primarily of restricted cash increased by $71.4 million to $298.4 million.

Construction funds increased by $65.3 million to $123.8 million, due to unspent proceeds from the 2014 bonds issued in early November designated to fund a portion of the ongoing capital improvement program.

The Rate Stabilization Account (RSA) increased by a net $4.4 million to a balance of $114.4 million as a result of operating cash transferred to the RSA during the year because net wholesale revenues were greater than budgeted. See Note 3 Rate Stabilization Account in the accompanying financial statements.

Bond reserve account deposits increased $1.1 million to $47.9 million from bond proceeds and interest earnings, and other restricted assets increased by $0.6 million to $12.3 million.

2013 Compared to 2012

Restricted assets consisting primarily of restricted cash decreased by $48.7 million to $227.0 million.

Construction funds decreased by $47.5 million to $58.5 million, as bond proceeds from the 2012 and 2013 bond issues were used to fund the ongoing capital improvement program. The ending balance of construction funds were from the 2013 bond issue.

In 2013, the Rate Stabilization Account (RSA) decreased by a net $18.3 million to a balance of $110.0 million. $40.0 million was transferred to operating cash from the RSA during the year to supplement lower than actual net wholesale revenues. In December 2013, operating cash in the amount of $21.0 million was transferred to the RSA in accordance with Ordinance No. 124426. The balance of $0.7 million transferred to the RSA was for interest earnings.

Bond reserve account deposits increased during the year by $12.6 million to $46.8 million; $10.0 million from operating cash and the balance of $2.6 million from 2013 bond proceeds and interest earnings. Other restricted accounts increase of $4.5 million to $11.7 million was due to an increase in the debt service account of $4.2 million and $0.3 million other.

Current Assets

2014 Compared to 2013

Current assets decreased by $70.3 million to $298.8 million at the end of 2014.

Operating cash decreased by $65.5 million to $128.3 million at the end of the year. Increased inflows to cash resulted from a 5.6% system average rate increase effective at the beginning of the year, Bonneville Power Administration (Bonneville) 1.2% pass-through rate adjustment, higher net wholesale energy sales, and reimbursement from the Construction account for certain capital expenditures. The higher cash inflows were offset by greater debt service payments, capital construction projects, ongoing operations, and transfers to the RSA.

Accounts receivable, net, increased by $10.6 million to $74.6 million. Wholesale power receivables increased by $5.9 million as a result of higher surplus sales during December. Other net receivables increased by $4.7 million including the recovery of costs expended on distribution system assets subject to co-ownership. The ongoing trend of improved collection efforts and revised allowance methodology for large service connection billings led to a lower allowance for bad debt for both retail and sundry sales receivables.

Unbilled revenues decreased by $14.2 million to $64.6 million due to lower retail customer loads compared to 2013.

Materials and supplies inventory increased $1.2 million to $30.8 million for ongoing operations.

2013 Compared to 2012

Current assets increased by $45.6 million to $369.1 million at the end of 2013.

Operating cash increased by $37.5 million to $193.8 million at the end of the year. Operating cash was higher in large part due to the 4.4% system average rate increase effective at the beginning of the year and the Bonneville Power Administration (Bonneville) 1.2% pass-through rate adjustment effective in October, and transfers from the RSA, offset by lower net wholesale energy sales, debt service payments, and transfer to the bond reserve account.

Accounts receivable, net, decreased by $2.4 million to $64.0 million. Wholesale power receivables decreased by $6.6 million as a result of lower surplus sales. Decreases totaling $2.3 million were also experienced in the reserve for uncollectible accounts, as improved collection efforts continued, along with decreases in other sundry receivables. These were offset by higher retail electric billings of $2.9 million, due in part to the aforementioned rate increases, and construction billings of $3.6 million.

Unbilled revenues increased by $7.8 million to $78.8 million, generally the result of 2013 rate increases. Inventory for materials and supplies increased by $2.9 million to $32.0 million and other current assets decreased by $0.2 million to $0.5 million.

Other Assets

2014 Compared to 2013

Other assets increased by $18.7 million to $319.7 million. Conservation costs, net, increased by $13.8 million. The regulatory asset for environmental cleanup costs increased by $2.8 million, mostly associated with cleanup of the Lower Duwamish Waterway Superfund Site. These environmental costs are being recovered through rates over a 25 year period. Other assets increased net $2.1 million. Additional detail for Other assets is provided in Note 6 Other Assets of the accompanying financial statements.

2013 Compared to 2012

Other assets increased by $22.1 million to $301.0 million. Conservation costs, net, increased by $13.2 million for ongoing focus on consumer conservation measures. The regulatory asset for environmental cleanup costs increased by $8.2 million and was largely associated with cleanup of the Lower Duwamish Waterway Superfund Site. Other charges within Other assets increased net $0.7 million.

Deferred Outflows of Resources

Deferred outflows of resources are specifically for Charges on advance refunding of prior lien bonds in recent years. In 2014, Charges on advance refunding decreased by $6.7 million for a total of $19.3 million. Charges on advance refunding decreased a net $4.0 million to $26.0 million in 2013 from 2012. Net activity is the result of additions due to new refunding bond issues and decreases due to amortization of costs.

LIABILITIES

Long-Term Debt

2014 Compared to 2013

Long-term debt increased a net $54.9 million to $1,925.2 million in 2014. In November, the Department issued $265.2 million of revenue and refunding revenue tax-exempt bonds to fund the ongoing capital improvement program and to advance refund $125.4 million of higher interest rate 2004 series bonds.

Debt to capitalization ratio was 59.9% at the end of 2014, a decrease from the 61.7% ratio of 2013 and continuing the favorable trend in recent years.

Net revenues available to pay debt service were equal to 1.85 times principal and interest on all bonds for 2014.

Note 7 Long-Term Debt of the accompanying financial statements provides additional information on the Department's long-term debt.

2013 Compared to 2012

Long-term debt increased a net $78.8 million to $1,870.3 million in 2013. In July 2013, the Department issued a total of $190.8 million of revenue and refunding revenue tax-exempt bonds to fund the ongoing capital improvement program and to advance refund certain higher interest bearing prior lien revenue bonds.

Debt to capitalization ratio was 61.7% at the end of 2013, a decrease from the 62.8% ratio of 2012.

Net revenues available to pay debt service were equal to 1.85 times principal and interest on all bonds for 2013.

Noncurrent Liabilities

2014 Compared to 2013

Total non-current liabilities decreased by $10.8 million to $67.3 million at the end of 2014.

Non-current environmental liabilities decreased by $12.2 million to $34.0 million. Environmental liabilities are primarily attributable to the estimated cost of remediating contaminated sediments in the lower Duwamish Waterway, a designated federal Superfund site. The Department is considered a potentially responsible party for contamination in the Duwamish River due to land ownership or use of property located along the river. During 2015, work will focus on clean-up on two sites; Terminal 117 and Cedar Falls Bridge remediation. Accordingly, a large amount of the non-current liability was reclassified to current.

The balance net decrease of $1.2 million to $24.4 million was negligible representing risk management liabilities, compensated absences, and other.

More information on environmental liabilities is found in Note 11 Environmental Liabilities and for other Noncurrent liabilities, primarily for risk management liabilities, in Note 8 Provision for Injuries and Damages of the accompanying financial statements.

2013 Compared to 2012

Total non-current liabilities increased by $3.3 million to $78.1 million at the end of 2013.

Non-current environmental liabilities increased by $1.0 million to $46.2 million for estimated updates to the Duwamish Waterway superfund site. Other non-current liabilities increased incrementally by $2.1 million for a total of $23.4 million at the end of 2013.

Current Liabilities

2014 Compared to 2013

Current liabilities increased by $16.6 million for a total of $258.3 million at the end of the year.

Of the net increase, $9.6 million was the result of higher environmental liabilities for ongoing clean-up of the Duwamish Waterway superfund site, with the net balance increase primarily for higher debt service from recent bond issues, and vouchers payable for ongoing operations.

2013 Compared to 2012

Current liabilities increased by $17.1 million for a total of $241.7 million at the end of 2013.

Of the net increase, $10.5 million was the result of higher debt service and the net balance increase was for vouchers payable for ongoing operations.

Other Liabilities

2014 Compared to 2013

Other liabilities increased by $7.5 million to $26.7 million in 2014. The major increase was for customer prepayments in the amount of $6.6 million for large service connections.

2013 Compared to 2012

Other liabilities increased by $3.8 million to $19.2 million in 2013. The major increase was for customer prepayments in the amount of $3.4 million for large service connections.

Deferred Inflows of Resources

2014 Compared to 2013

Deferred inflows of resources increased by $10.8 million for a total of $111.5 million at the end of 2014.

The significant activity occurring since 2010 has been principally the result of implementing, funding, and related activity of the RSA. Funding of the RSA from operating cash has the corresponding effect of deferring operating revenues in the rate stabilization unearned revenue account and vice versa. During 2014, $4.4 million net was transferred to the rate stabilization unearned revenue account from operating revenues as a result of higher actual net wholesale revenues than budget. The ending balance of the rate stabilization unearned revenue account was $89.4 million. See Note 3 Rate Stabilization Account in the accompanying financial statements for more information on the RSA.

Other deferred inflows of resources increased by $6.4 million to $22.1 million. The increase was mostly due to payments received from Bonneville in accordance with the Department's Energy Conservation Agreement, net of earned revenue totaling $6.0 million. The net balance was due to a higher Bonneville Slice true-up credit and exchange energy regulatory gains.

2013 Compared to 2012

Deferred inflows of resources decreased by $11.8 million for a totaled of $100.7 million at the end of the year.

Net transfer of $18.3 million was made from the rate stabilization unearned revenue account to operating revenues to supplement lower than budgeted net wholesale revenues. Ending balance of the rate stabilization unearned revenue account was $85.0 million.

Other deferred inflows of resources increased by $6.5 million to $15.7 million. Energy Conservation Agreement payments received were higher by $3.1 million and Bonneville's Slice true-up credit increased by $2.7 million compared to 2012. The balance was the result of exchange energy regulatory gains.

RESULTS OF OPERATIONS

Condensed Statements of Revenues, Expenses, and Changes in Net Position

	Year Ended December 31		
($ in millions)	2014	2013	2012 [(a)]
Operating revenues	$ 886.4	$ 842.2	$ 800.3
Nonoperating revenues	18.5	11.1	12.7
Total revenues	904.9	853.3	813.0
Operating expenses	734.1	711.0	662.0
Nonoperating expenses	77.9	79.3	78.8
Total expenses	812.0	790.3	740.8
Income before capital contributions and grants	92.9	63.0	72.2
Capital contributions	27.7	47.9	31.0
Capital grants	0.7	1.8	0.8
Total capital contributions and grants	28.4	49.7	31.8
Change in net position	$ 121.3	$ 112.7	$ 104.0

(a) GASB No. 65, *Items Previously Reported as Assets and Liabilities,* was implemented effective January 2013. Accordingly, the 2012 Statement of Revenues, Expenses, and Changes in Net Position was restated to conform to the 2013 presentation. See Note 1 Operations and Summary of Significant Accounting Policies.

SUMMARY

2014 Compared to 2013

Change in net position for 2014 was $121.3 million, an increase of $8.6 million or 7.6% from 2013 change in net position of $112.7 million. Higher retail electric sales, net wholesale energy sales, and investment earnings were offset in part by higher power related expenses, conservation, administrative and general, taxes, and depreciation. Lower transfers from/(to) RSA and capital contributions also decreased revenues.

2013 Compared to 2012

Change in net position for 2013 was $112.7 million, an increase of $8.7 million or 8.4% from 2012 restated change in net position of $104.0 million. Higher retail power sales, RSA unearned revenue transferred-in, power related revenues, and capital contributions added to the positive change in net position. These were partially offset by higher expenses for generation, customer service, administrative and general, taxes, depreciation, interest, and lower investment earnings. The net impact of adopting GASB No. 65 was $1.6 million reduction in Change in net position for 2012.

REVENUES

2014 Compared to 2013

Total operating revenues were $886.4 million, an increase of $44.2 million or 5.3% from 2013. Retail power revenues at $720.8 million increased $23.1 million, Wholesale power revenues at $96.8 million increased $33.8 million, Other power revenues at $50.8 million increased $10.4 million, Transfers from/(to) RSA at ($4.4) million decreased $22.7 million, and Other operating revenues at $22.4 million decreased $0.4 million. Retail power revenues were higher as a result of the 5.6% across-the-board rate increase effective January 1, 2014 and the 1.2% Bonneville pass-through rate adjustment effective in October 2013. Actual net wholesale power revenues were higher than budgeted and therefore, $4.4 million net was transferred to the RSA unearned revenue account. In 2013, $18.3 million net was transferred-in from the RSA unearned revenue account to supplement lower net wholesale energy revenues than budget. The net effect of transactions in the Transfers from/(to) RSA between years was a reduction of $22.7 million in operating revenues.

Net wholesale energy revenues were $81.9 million, an increase of $38.7 million or 89.6% from net wholesale energy revenues of $43.2 million in 2013. On an annual basis, the Department expects to be a net seller in the wholesale energy market. During 2014, higher surplus energy that was available for sale due to a strong water year along with higher wholesale power prices contributed to the improved net wholesale energy revenues. Other power revenues were higher by a net $6.8 million from 2013 generally on the basis of higher valuation of net power exchange revenues and the higher wholesale power prices.

2013 Compared to 2012

Total operating revenues were $842.2 million, an increase of $41.9 million or 5.2% from 2012. Retail power revenues at $697.7 million increased $33.4 million, Wholesale power revenues at $63.0 million decreased $7.4 million, Other power revenues at $40.4 million increased $11.1 million, Transfers from/(to) RSA at $18.3 million increased $5.1 million, and Other operating revenues at $22.8 million decreased $0.3 million. Retail power revenues were higher as a result of the 4.4% across-the-board rate increase effective January 1, 2013 and the 1.2% Bonneville pass-through rate adjustment effective in October 2013. Operating revenues were supplemented by Transfers from/(to) Rate Stabilization Account in accordance with Ordinance No. 123260. A net $18.3 million of RSA unearned revenue was transferred-in to supplement lower than budget net wholesale revenues. This was inclusive of $21.0 million transferred to unearned revenue in December 2013 corresponding to the operating cash transferred to the RSA in excess of the estimated amount needed to achieve in excess of 1.80x debt service coverage in accordance with Ordinance No. 124426. The Department is required to set rates designed to achieve debt service coverage of 1.80x.

Net wholesale energy revenues were $43.2 million, a decrease of $15.4 million or 26.3% from net wholesale energy revenues of $58.6 million in 2012. During 2013, lower surplus energy available for sale, despite an increase in wholesale power prices, was a factor in the continued declining trend in recent years of lower net wholesale energy revenues. Other power revenues were higher by a net $4.8 million from 2012 predominantly the result of higher valuation of net power exchange revenues because of the higher wholesale power prices.

EXPENSES

2014 Compared to 2013

Operating expenses totaled $734.1 million, an increase of $23.1 million or 3.3% from $711.0 million in 2013.

Power-related operating expenses at $347.9 million were higher by $10.5 million or 3.1%. These expenses were comprised of Bonneville purchased power of $155.6 million, which increased $5.5 million, Short-term wholesale power purchases of $14.9 million, which decreased $4.9 million, power-related wholesale purchases of $17.7 million, which increased $3.6 million, and other power-related expenses, including Transmission and Generation of $159.7 million, which increased $6.3 million.

Bonneville purchased power costs increased $5.5 million generally due to increased power rates effective October 2013 plus a higher block load shaping rate. The net increase of $6.3 million power-related expenses was the result of higher Bonneville transmission costs of $4.6 million and higher power exchange transactions netting to $5.7 million on higher volumes and power prices.

Non-power operating expenses increased by $8.4 million to $200.4 million or 4.4% from $192.0 million in 2013. These expenses included Distribution expenses of $59.7 million, unchanged, Customer service of $37.6 million, which decreased $1.6 million, Conservation of $27.3 million, which increased $5.8 million, and Administrative and general, net, of $75.8 million which increased $4.1 million.

Customer service expenses were higher due to increased temporary labor for low income outreach and meter reading, and customer contract expenses due to increased service connections, offset by lower bad debt expense. Conservation expenses increased because of higher amortization for commercial and residential programs, and higher customer renewable solar energy credits. Administrative and general, net, were higher because of general office salaries due to a lower vacancy rate along with higher professional service fees.

Taxes at $80.0 million increased $0.7 million due to higher revenues and included the effect of $2.8 million of conservation incentive tax credits. Depreciation and amortization at $105.8 million increased by $3.5 million as a result of additional plant assets placed in service.

2013 Compared to 2012

Operating expenses totaled $711.0 million, an increase of $49.0 million or 7.4% from $662.0 million in 2012.

Power-related expenses at $337.4 million were higher by $24.1 million or 7.7%. These expenses entailed Bonneville purchased power of $150.1 million, which increased $0.8 million, Short-term wholesale power purchases of $19.8 million, which increased $8.0 million, power-related wholesale purchases of $14.1 million, which increased $6.3 million, and other power-related expenses, including Transmission and Generation of $153.4 million, which increased $9.0 million.

Although MWhs purchased for Short-term wholesale power purchases were lower compared to 2012, the higher wholesale power prices during 2013 added to the higher expenses. Increased transactions for power exchanges along with the higher wholesale power prices accounted for the increased power-related wholesale purchases. The write-off for Gorge second tunnel costs of $6.6 million plus higher FERC fees of $3.0 million, offset by operation costs, encompassed the $9.0 million variance for other power-related expenses. Bonneville purchased power and transmission expenses were not significantly different from 2012.

Non-power operating expenses increased by $13.0 million to $192.0 million or 7.3% from $179.0 million in 2012. These expenses included Distribution expenses of $59.5 million, which decreased $1.3 million, Customer service of $39.2 million, which increased $7.9 million, Conservation of $21.5 million, which increased $0.8 million, and Administrative and general, net, of $71.7 million which increased $5.6 million.

Customer service expense was higher primarily due to higher billing and collection expenses, billing system operating expenses, and bad debt expense. The comparative bad debt expense for 2012 was lower as a result of lower receivables in part due to improved collections. Administrative and general, net, are higher because of higher salaries for COLA adjustments, new positions, and higher pension and benefits expenses.

Taxes at $79.3 million increased $4.4 million due to higher revenues. Depreciation and amortization at $102.3 million increased by $7.5 million as a result of additional plant assets placed in service.

NONOPERATING REVENUES AND (EXPENSES), CAPITAL CONTRIBUTIONS AND GRANTS

2014 Compared to 2013

Nonoperating revenues increased by $7.4 million to $18.5 million in 2014. The major contributor was a substantial gain in investment income of $7.1 million due to the favorable swing between years in unrealized fair value gains for the Department's share of investments in the city cash pool.

Nonoperating expense was slightly lower by $1.4 million to $77.9 million. Higher interest charged to construction projects of $1.9 million was the main component as there was increased focus on capital work during the year.

Capital contributions and grants decreased by $21.3 million to $28.4 million in 2014. Capital contributions were lower by $20.2 primarily due to lower in-kind contributions totaling $21.8 million. The decrease of in-kind amounts from 2013 was primarily for the Mercer East corridor project and other private construction.

2013 Compared to 2012

Nonoperating revenues decreased by $1.6 million to $11.1 million in 2013. Investment income was lower by $4.4 million largely due to unrealized losses for the Department's share of fair value adjustments from investments in the city cash pool. This was offset by higher sales for several surplus real estate properties of $2.2 million, and $0.8 million of higher noncapital grants and other revenues.

Nonoperating expense was slightly higher by $0.5 million to $79.3 million. Higher interest expense on prior lien bonds was offset by lower costs of issuance, amortization of refunding loss, and higher bond premium amortization.

Capital contributions and grants increased by $17.9 million to $49.7 million in 2013. Capital contributions were higher by $16.9 primarily due to higher in-kind contributions totaling $21.8 million, including $13.3 million of underground assets contributed by the Seattle Department of Transportation for the Mercer East corridor project and other construction projects. These were offset by $8.9 million of lower underground electrical infrastructure improvements for the cities of Shoreline and Burien compared to 2012. Capital grants increased by $1.0 million to $1.8 million in 2013 mainly for work related to the Sound Transit Northlink project in progress.

RISK MANAGEMENT

The Department began implementing an Enterprise-wide Risk Management (ERM) process in 2008 to establish a full spectrum approach to risk management that links important decision making functions through a standardized process of identifying, assessing, monitoring, and mitigating risks across all Business Units and Divisions of the Department.

Risk Oversight Council (ROC) oversees wholesale power marketing activities. It is comprised of the Chief Financial Officer (Chair), Power Supply & Environmental Affairs Officer, Director of Risk Oversight, Director of Power Operations and Marketing (non-voting), Director of Power Contracts & Resource Acquisition (non-voting), and Manager of Financial Planning (non-voting). The ROC guides the continuous improvement of energy risk management activities and capabilities, approves hedging strategies, hedging plans, and approves changes to relevant operating procedures.

The Risk Oversight Division, in addition to the ERM, manages the market and credit risk related to all wholesale marketing activities, and carries out the middle office functions of the Department. This includes confirmations, risk controls, independent reporting of market positions, counterparty credit risk, settlements, and ensuring adherence to Wholesale Energy Risk Management (WERM) policy and procedures.

Hydro Risk

Due to the Department's primary reliance on hydroelectric generation, weather can significantly affect its operations. Hydroelectric generation depends on the amount of snow-pack in the mountains upstream of the Department's hydroelectric facilities, springtime snow-melt, run-off and rainfall. Hydroelectric operations are also influenced by flood control and environmental matters, including protection of fish. In low-water years, the Department's generation is reduced and the use of wholesale purchased power may increase in order to meet load. Normally, the Department experiences electricity usage peaks in winter; however, extreme weather conditions affecting either heating or cooling needs could cause the Department's seasonal fluctuations to be more pronounced and increase costs. In addition, economic trends (increase or decrease in business activity, housing sales and development of properties) can affect demand and change or increase costs.

Energy Market Risk

For the Department, energy market risk is the risk of adverse fluctuations in the price of wholesale electricity, which is compounded by volumetric changes affecting the availability of, or demand for electricity. Factors that contribute to energy market risk include: regional planned and unplanned generation plant outages, transmission constraints or disruptions, the number of active creditworthy market participants willing to transact, and environmental regulations that influence the availability of generation resources.

The Department's exposure to hydro volumetric and energy market risk is managed by the ROC and the approved strategies are executed by the Power Operations and Marketing Division. The Department engages in market transactions to meet its load obligations and to realize earnings from surplus energy resources.

With a significant portion of the Department's revenue expected from wholesale energy market sales, great emphasis is placed on the management of risks associated with this activity. Policies, procedures, and processes designed to manage, control and monitor these risks are in place. A formal front, middle, and back office structure is in place to ensure proper segregation of duties.

The Department measures the risk in its energy portfolio using a model that utilizes historical simulation methodology and incorporates not only price risk, but also the volumetric risk associated with its hydro-dominated power portfolio. Scenario analysis is used for stress testing.

Credit Risk

Credit risk is the risk of loss that would be incurred as a result of nonperformance by counterparties of their contractual obligations. If a counterparty failed to perform on its contractual obligation to deliver electricity, then the Department may find it necessary to procure electricity at current market prices, which may be higher than the contract price. If a counterparty failed to pay its obligation in a timely manner, this would have an impact on the Department's revenue and cash flow. As with market risk, the Department has policies governing the management of credit risk.

Wholesale counterparties are assigned credit limits based on publicly available and proprietary financial information. Along with ratings provided by national ratings agencies, an internal credit scoring model is used to classify counterparties into one of several categories with permissible ranges of credit limits. Specific counterparty credit limits are set within this prescribed range based on qualitative and quantitative factors. Credit limits are also used to manage counterparty concentration risk. The Department is actively reducing concentration of credit risk related to geographic location of counterparties as it only transacts in the western energy markets. This geographic concentration of counterparties may impact the Department's overall credit exposure, because counterparties may be affected by similar conditions.

Credit limits, exposures and credit quality are actively monitored on a daily basis. Despite such efforts, there is potential for default, however the Department has not had a counterparty default in the last 10 years. The Department transacts with counterparties on an uncollateralized and collateralized basis. Posted collateral may be in the form of cash, letters of credit, or parental guarantees.

REQUESTS FOR INFORMATION

For more information about Seattle City Light, contact Marketing and Communications at 206-684-3090 or at P.O. Box 34023, Seattle, WA 98124-4023.

THIS PAGE IS INTENTIONALLY LEFT BLANK

THE CITY OF SEATTLE—CITY LIGHT DEPARTMENT

BALANCE SHEETS - ASSETS AND DEFERRED OUTFLOWS OF RESOURCES
AS OF DECEMBER 31, 2014 AND 2013

($ in millions)	**2014**	**2013**
ASSETS		
UTILITY PLANT—At original cost:		
Plant-in-service—excluding land	$ 3,936.0	$ 3,795.3
Less accumulated depreciation and amortization	(1,611.5)	(1,563.9)
Total plant-in-service—net	2,324.5	2,231.4
Construction work-in-progress	251.0	164.1
Nonoperating property—net of accumulated depreciation	10.5	8.7
Assets held for future use	71.8	68.7
Land and land rights	70.5	68.2
Total utility plant—net	2,728.3	2,541.1
RESTRICTED ASSETS:		
Rate Stabilization Account	114.4	110.0
Municipal light and power bond reserve account	47.9	46.8
Construction—Cash and equity in pooled investments	123.8	58.5
Special deposits and other restricted assets	12.3	11.7
Total restricted assets	298.4	227.0
CURRENT ASSETS:		
Cash and equity in pooled investments	128.3	193.8
Accounts receivable (includes $1.6 and $2.8 at fair value), net of allowance of $7.7 and $9.4	73.1	63.2
Interfund receivable	1.5	0.8
Unbilled revenues	64.6	78.8
Materials and supplies at average cost	30.8	32.0
Prepayments, interest receivable, and other current assets	0.5	0.5
Total current assets	298.8	369.1
OTHER ASSETS:		
Conservation costs—net	228.1	214.3
Environmental costs—net	34.5	31.7
Other charges and assets—net	57.1	55.0
Total other assets	319.7	301.0
TOTAL ASSETS	3,645.2	3,438.2
DEFERRED OUTFLOWS OF RESOURCES—Charges on advance refunding	19.3	26.0
TOTAL ASSETS AND DEFERRED OUTFLOWS OF RESOURCES	$ 3,664.5	$ 3,464.2

See notes to financial statements.

THE CITY OF SEATTLE—CITY LIGHT DEPARTMENT

BALANCE SHEETS - LIABILITIES, DEFERRED INFLOWS OF RESOURCES, AND NET POSITION AS OF DECEMBER 31, 2014 AND 2013

($ in millions)	**2014**	**2013**
LIABILITIES		
LONG-TERM DEBT:		
Revenue bonds	$ 1,903.8	$ 1,863.3
Plus bond premium—net	126.3	106.7
Less revenue bonds—current portion	(104.9)	(99.7)
Total long-term debt	1,925.2	1,870.3
NONCURRENT LIABILITIES:		
Accumulated provision for injuries and damages	42.9	54.9
Compensated absences	16.7	15.5
Other noncurrent liabilities	7.7	7.7
Total noncurrent liabilities	67.3	78.1
CURRENT LIABILITIES:		
Accounts payable and other current liabilities	101.3	90.7
Interfund payable	10.9	9.7
Accrued payroll and related taxes	9.2	7.5
Compensated absences	2.0	2.0
Accrued interest	30.0	32.1
Long-term debt—current portion	104.9	99.7
Total current liabilities	258.3	241.7
OTHER LIABILITIES	26.7	19.2
TOTAL LIABILITIES	2,277.5	2,209.3
DEFERRED INFLOWS OF RESOURCES		
Rate stabilization unearned revenue	89.4	85.0
Other deferred inflows of resources (includes $0.1 and $1.0 at fair value)	22.1	15.7
TOTAL DEFERRED INFLOWS OF RESOURCES	111.5	100.7
NET POSITION		
Net investment in capital assets	1,100.8	906.1
Restricted:		
Rate stabilization account	25.0	25.0
Special deposits and other purposes	-	(0.4)
Total restricted	25.0	24.6
Unrestricted—net	149.7	223.5
Total net position	1,275.5	1,154.2
TOTAL LIABILITIES, DEFERRED INFLOWS OF RESOURCES, AND NET POSITION	$ 3,664.5	$ 3,464.2

See notes to financial statements.

THE CITY OF SEATTLE—CITY LIGHT DEPARTMENT

STATEMENTS OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
FOR THE YEARS ENDED DECEMBER 31, 2014 AND 2013

($ in millions)	**2014**	**2013**
OPERATING REVENUES:		
Retail power revenues	$ 720.8	$ 697.7
Short-term wholesale power revenues	96.8	63.0
Other power-related revenues	50.8	40.4
Transfers from/(to) rate stabilization account	(4.4)	18.3
Other operating revenues	22.4	22.8
Total operating revenues	886.4	842.2
OPERATING EXPENSES:		
Long-term purchased power—Bonneville and other	214.3	203.1
Short-term wholesale power purchases	14.9	19.8
Other power expenses	65.9	66.4
Transmission	52.8	48.2
Distribution	59.7	59.5
Customer service	37.6	39.2
Conservation	27.3	21.5
Administrative and general	75.8	71.7
Taxes	80.0	79.3
Depreciation and amortization	105.8	102.3
Total operating expenses	734.1	711.0
OPERATING INCOME	152.3	131.2
NONOPERATING REVENUES AND (EXPENSES):		
Other revenues and (expenses)—net	18.5	11.1
Interest expense		
Interest expense—net	(85.3)	(86.4)
Amortization of bond costs—net	7.4	7.1
Total interest expense	(77.9)	(79.3)
Total nonoperating expenses	(59.4)	(68.2)
INCOME BEFORE CAPITAL CONTRIBUTIONS AND GRANTS	92.9	63.0
CAPITAL CONTRIBUTIONS AND GRANTS:		
Capital contributions	27.7	47.9
Capital grants	0.7	1.8
Total capital contributions and grants	28.4	49.7
CHANGE IN NET POSITION	121.3	112.7
NET POSITION:		
Beginning of year	1,154.2	1,041.5
End of year	$ 1,275.5	$ 1,154.2

See notes to financial statements.

THE CITY OF SEATTLE—CITY LIGHT DEPARTMENT

STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2014 AND 2013

($ in millions)	2014	2013
OPERATING ACTIVITIES:		
Cash received from customers and counterparties	$ 867.4	$ 811.6
Interfund operating cash received	1.7	2.6
Cash paid to suppliers and counterparties	(287.1)	(325.6)
Cash paid to employees	(173.6)	(153.3)
Interfund operating cash paid	(28.5)	(26.4)
Taxes paid	(82.3)	(79.2)
Net cash provided by operating activities	297.6	229.7
NONCAPITAL FINANCING ACTIVITIES:		
Principal paid on long-term debt	(37.3)	(17.9)
Interest paid on long-term debt	(33.7)	(16.8)
Noncapital grants received	5.2	1.8
Bonneville receipts for conservation	6.7	3.6
Payment to vendors on behalf of customers for conservation	(33.1)	(31.0)
Net cash used in noncapital financing activities	(92.2)	(60.3)
CAPITAL AND RELATED FINANCING ACTIVITIES:		
Proceeds from long-term debt	265.2	190.7
Proceeds from long-term debt premiums	34.2	13.7
Payment to trustee for defeased bonds	(127.1)	(15.2)
Bond issue costs paid	(1.7)	(1.2)
Principal paid on long-term debt	(62.4)	(73.9)
Interest paid on long-term debt	(56.5)	(69.3)
Acquisition and construction of capital assets	(276.1)	(257.2)
Interfund payments for acquisition and construction of capital assets	(10.9)	(4.5)
Capital contributions	26.5	30.6
Interfund receipts for capital contributions	0.8	0.3
Capital grants received/(paid)	(3.0)	2.3
Interest received for suburban infrastructure improvements	2.1	1.8
Proceeds on sale of property	2.0	2.1
(Increase) Decrease in other assets	1.6	0.3
Net cash used in capital and related financing activities	(205.3)	(179.5)
INVESTING ACTIVITIES:		
Interest received (paid) on investments and on cash and equity in pooled investments	5.8	(1.1)
Net cash provided by (used in) investing activities	5.8	(1.1)
NET INCREASE (DECREASE) IN CASH AND EQUITY IN POOLED INVESTMENTS	5.9	(11.2)
CASH AND EQUITY IN POOLED INVESTMENTS:		
Beginning of year	420.8	432.0
End of year	$ 426.7	$ 420.8

See notes to financial statements.

THE CITY OF SEATTLE—CITY LIGHT DEPARTMENT

STATEMENTS OF CASH FLOWS - RECONCILIATION
FOR THE YEARS ENDED DECEMBER 31, 2014 AND 2013

($ in millions)	**2014**	**2013**
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Operating income	$ 152.3	$ 131.2
Adjustments to reconcile operating income to net cash provided by operating activities:		
Non-cash items included in operating income:		
Depreciation	108.1	104.3
Amortization of other liabilities	(0.6)	(0.4)
Amortization of other assets	22.7	19.9
Bad debt expense	2.1	5.1
Power revenues	(48.4)	(27.0)
Power expenses	49.1	26.7
Provision for injuries and damages	(0.3)	1.0
Other non-cash items	5.8	8.2
Change in:		
Accounts receivable	(10.7)	(2.9)
Unbilled revenues	14.2	(7.8)
Materials and supplies	6.6	(7.5)
Prepayments, interest receivable, and other receivables	0.6	3.4
Other assets	(2.9)	(9.2)
Provision for injuries and damages and claims payable	(13.8)	0.4
Accounts payable and other payables	8.4	2.6
Rate stabilization unearned revenue	4.4	(18.3)
Total adjustments	145.3	98.5
Net cash provided by operating activities	$ 297.6	$ 229.7
SUPPLEMENTAL DISCLOSURES OF NONCASH ACTIVITIES:		
In-kind capital contributions	$ 3.6	$ 22.3
Amortization of debt related costs—net (restated)	7.4	7.1
Change in valuation of power exchange assets or liabilities	-	(0.7)
Allowance for funds used during construction	5.8	3.8
Power exchange revenues	25.3	5.2
Power exchange expenses	(25.6)	(5.0)
Power revenue netted against power expenses	6.1	6.5
Power expense netted against power revenues	(17.1)	(14.9)

See notes to financial statements.

1. OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The City Light Department (the Department) is the public electric utility of The City of Seattle (the City). The Department is an enterprise fund of the City. The Department owns and operates certain generating, transmission, and distribution facilities and supplies electricity to approximately 415,000 residential, commercial, and public customers in the city of Seattle. The Department also supplies electrical energy to other City agencies at rates prescribed by City ordinances, and to certain neighboring communities under franchise agreements. The establishment of the Department's rates is within the exclusive jurisdiction of the Seattle City Council. A requirement of Washington State law provides that rates must be fair, nondiscriminatory, and fixed to produce revenue adequate to pay for operation and maintenance expenses and to meet all debt service requirements payable from such revenue. The Department pays occupation taxes to the City based on total revenues.

The Department's revenues for services provided to other City departments were $18.8 million and $18.3 million in 2014 and 2013, respectively, and $3.0 and $2.9 million for non-energy services, respectively.

The Department receives certain services from other City departments and paid $50.8 million in 2014 and $44.9 million in 2013, for such services. Amounts paid include central cost allocations from the City for services received including treasury services, risk financing, purchasing, data processing systems, vehicle maintenance, personnel, payroll, legal, administrative, and building rentals, including for the Department's administrative offices.

The Department's receivables from other City departments totaled $1.5 million and $0.8 million at December 31, 2014, and 2013, respectively. The Department's payables to other City departments totaled $10.9 million and $9.7 million at December 31, 2014, and 2013, respectively. The balances receivable and payable are the result of transactions incurred in the normal course of operations.

Basis of Presentation and Accounting Standards—The financial statements are prepared using the economic resources measurement focus and the accrual basis of accounting in conformity with accounting principles generally accepted in the United States of America as applied to governmental units. Revenues are recorded when earned and expenses are recorded when a liability is incurred, regardless of the timing of related cash flows. The Governmental Accounting Standards Board (GASB) is the accepted standard-setting body for establishing governmental accounting and financial reporting principles. The Department has applied and is current through 2014 with all applicable GASB pronouncements.

The GASB issued GASB Statement No. 68, *Accounting and Financial Reporting for Pensions – an amendment of GASB Statement No. 27*, Statement No. 71, *Pension Transition for Contributions Made Subsequent to the Measurement Date – an amendment of GASB Statement No. 68*, and Statement No. 72, *Fair Value Measurement and Application*. These statements will be effective for the Department in future years and application of these standards may restate portions of these financial statements.

Fair Value Measurements—Descriptions of the Department's accounting policies on fair value measurements for items reported on the balance sheets at December 31, 2014 and 2013, are as noted in the following paragraph, Note 5 Accounts Receivable, and Note 15 Long-Term Purchased Power, Exchanges, and Transmission.

Fair Value of Financial Instruments—The Department's financial instruments reported on the balance sheets at December 31, 2014 and 2013, as Restricted assets and Cash and equity in pooled investments are measured at fair value. These instruments consist primarily of the Department's share of the City-wide pool of investments (see Note 4 Cash and Equity in Pooled Investments and Investments). Gains and losses on these financial instruments are reflected in Investment income in the statements of revenues, expenses, and changes in net position. Long-term debt at December 31, 2014 and 2013, is disclosed at fair value (see Note 7 Long-Term Debt).

Net Position—The Department classifies its net position into three components as follows:

- *Net investment in capital assets*—This component consists of capital assets, net of accumulated depreciation and amortization, reduced by the net outstanding debt balances related to capital assets net of unamortized debt expenses.

- *Restricted*—This component consists of net position with constraints placed on use. Constraints include those imposed by creditors (such as through debt covenants and excluding amounts considered in net capital, above), grants, or laws and regulations of other governments, or by enabling legislation, The City of Seattle Charter, or by ordinances legislated by the Seattle City Council.

- *Unrestricted*—This component consists of assets and liabilities that do not meet the definition of Net investment in capital assets or Restricted.

Restricted and Unrestricted Net Position—The Department's policy is to use restricted net position for specified purposes and to use unrestricted net position for operating expenses. The Department does not currently incur expenses for which both restricted and unrestricted net position is available.

Assets Held for Future Use—These assets include property acquired but never used by the Department in electrical service and therefore, held for future service under a definitive plan. Also included is property previously used in service but retired and held pending its reuse in the future under a definitive plan. As of December 31, 2014 and 2013, Assets held for future use included the following electrical plant assets: land for future substations, ducts and vaults, transmission lines, and plans for additional hydraulic generating capacity totaling $71.8 million and $68.7 million, respectively.

Materials and Supplies—Materials and supplies are generally used for construction, operation and maintenance work, not for resale. They are valued utilizing the average cost method and charged to construction or expense when used.

Revenue Recognition—Service rates are authorized by City ordinances. Billings are made to customers on a monthly or bimonthly basis. Revenues for energy delivered to customers between the last billing date and the end of the year are estimated and reflected in the accompanying financial statements as unbilled revenue within Retail power revenues.

The Department's customer base accounted for electric energy sales at December 31, 2014 and 2013, as follows:

	2014	2013
Residential	36.1 %	37.3 %
Nonresidential	63.9 %	62.7 %
Total	100.0 %	100.0 %

Revenues earned in the process of delivering energy to customers, wholesale energy transactions, and related activities are considered operating revenues in the determination of change in net position. Investment income, nonexchange transactions, and other revenues are considered Nonoperating revenues.

Expense Recognition**—**Expenses incurred in the process of delivering energy to customers, wholesale energy transactions, and related activities are considered operating expenses in the determination of net income. Debt interest expense, debt related amortization, and certain other expenses are considered Nonoperating expenses.

Administrative and General Overhead Costs Applied**—**Certain administrative and general overhead costs are allocated to construction work-in-progress, major data processing systems development, programmatic conservation, relicensing mitigation projects, and billable operations and maintenance activities based on rates established by cost studies. Pension and benefit costs are allocated to capital and operations and maintenance activities based on a percentage of labor dollars. The administrative and general overhead costs applied totaled $48.1 million and $42.2 million in 2014 and 2013, respectively. Pension and benefit costs were $52.6 million and $50.1 million in 2014 and 2013, respectively. Administrative and general expenses, net of total applied overhead, were $75.8 million and $71.7 million in 2014 and 2013, respectively.

Interest Charged to Construction**—**Interest is charged for funds used during construction of plant assets and to non-billable construction work-in-progress. Interest charged represents the estimated costs of financing construction projects and is computed using the Department's weighted-average interest rate for all bonds outstanding, the majority of which are tax exempt, and is revised when new bonds are issued and at the end of the year. Interest charged to construction totaled $5.8 million and $3.8 million in 2014 and 2013, respectively, and is reflected as a reduction of Interest expense in the statements of revenues, expenses, and changes in net position.

Nonexchange Transactions**—**Capital contributions and grants in the amount of $32.2 million and $52.9 million are reported for 2014 and 2013, respectively, in the statements of revenues, expenses, and changes in net position as nonoperating revenues from nonexchange transactions. Capital contributions and grants revenues are recognized based on the accrual basis of accounting. In-kind capital contributions are recognized at estimated fair value in the period when all eligibility requirements have been met as described in GASB Statement No. 33, *Accounting and Financial Reporting for Nonexchange Transactions*. Federal and state grant revenues are recognized as earned and are subject to contract and other compliance audits.

Compensated Absences—Regular employees of the Department earn vacation time in accordance with length of service. A maximum of 480 hours may be accumulated for the most tenured employees and, upon termination, employees are entitled to compensation for unused vacation. Upon retirement, employees receive compensation equivalent to 25% of their accumulated sick leave. Effective 2006, only employees represented by unions who voted in favor of a Healthcare Reimbursement Arrangement (HRA) receive 35% of their sick leave balance tax-free through an HRA account for healthcare expenses post retirement. Because of the special tax arrangement, the sick leave balance may only go into the HRA account; it may not be taken as a cashout. The HRA program is administered by an independent third party administrator, Meritain Health. HRA investments are managed by HRA Voluntary Employee Beneficiary Association (VEBA) Trust. The Department accrues all costs associated with compensated absences, including payroll taxes.

Use of Estimates—The preparation of the financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect amounts reported in the financial statements. The Department used significant estimates in determining reported allowance for doubtful accounts, unbilled revenues, power exchanges, accumulated provision for injuries and damages and workers' compensation, environmental liabilities, accrued sick leave, other postemployment benefits, and other contingencies. Actual results may differ from those estimates.

Significant Risk and Uncertainty—The Department is subject to certain business risks that could have a material impact on future operations and financial performance. These risks include financial market liquidity and economic uncertainty; prices on the wholesale markets for short-term power transactions; interest rates and other inputs and techniques for fair valuation; water conditions, weather, climate change, and natural disaster-related disruptions; terrorism; collective bargaining labor disputes; fish and other Endangered Species Act (ESA) issues; Environmental Protection Agency (EPA) regulations; compliance with clean and renewable energy legislation; local and federal government regulations or orders concerning the operations, maintenance, and/or licensing of hydroelectric facilities; other governmental regulations; restructuring of the electrical utility industry; and the costs of constructing transmission facilities that may be incurred as part of a northwest regional transmission system, and related effects of this system on transmission rights, transmission sales, surplus energy, and governance.

2. UTILITY PLANT

Utility Plant—Utility plant is recorded at original cost, which includes both direct costs of construction or acquisition and indirect costs, including an allowance for funds used during construction. The capitalization threshold for tangible assets was $5,000, and for intangible assets, $500,000 in 2014 and 2013. Plant constructed with capital contributions or contributions in-aid-of construction received from customers is included in Utility plant. Capital contributions and capital grants totaled $28.4 million in 2014 and $49.7 million in 2013. The Department uses a straight-line composite method of depreciation and amortization and, therefore, groups assets into composite groups for purposes of depreciation. Estimated economic lives range from 4 to 57 years. The Department uses a half-year convention method on the assumption that additions and replacements are placed in service at mid-year. Depreciation and amortization expense as a percentage of depreciable utility plant-in-service was approximately 2.7% in 2014 and 2.7% in 2013. When operating plant assets are retired, their original cost together with retirement costs and removal costs, less salvage, is charged to accumulated depreciation or amortization, if applicable. The cost of maintenance and repairs is charged to expense as incurred, while the cost of replacements and betterments are capitalized. The Department periodically reviews long-lived assets for impairment to determine whether any events or circumstances indicate the carrying value of the assets may not be recoverable over their economic lives.

At December 31, 2014, and 2013, assets of $1.8 million and $2.5 million, respectively, were identified as temporarily impaired due to construction stoppage, in order that the Department could focus on higher priority projects. Of the assets that were temporarily impaired, $1.8 million and $0.7 million are included in Assets held for future use at December 31, 2014, and 2013, respectively, and $1.8 million is included in Construction work-in-process at December 31, 2013.

Intangible assets are those that lack physical substance, are nonfinancial in nature, and have useful lives extending beyond a single reporting period. The Department's intangible assets are reported as capital assets under Utility Plant. The Department's intangible assets consist of easements, purchased and internally developed software, transmission rights, capitalized relicensing costs for Skagit and Boundary hydroelectric projects, Tolt hydroelectric project mitigation costs, and costs capitalized under the High Ross Agreement.

Utility plant-in-service at original cost, excluding land, at December 31, 2014, and 2013, was:

2014 *($ in millions)*	**Hydroelectric Production**	**Transmission**	**Distribution**	**General**	**Intangible**	**Total**
Original cost:						
Beginning balance	$ 761.2	$ 201.9	$ 2,086.4	$ 305.2	$ 440.6	$ 3,795.3
Capital acquisitions	28.6	6.0	118.9	18.1	27.4	199.0
Dispositions	(26.2)	(0.1)	(11.1)	(9.4)	(11.5)	(58.3)
Transfers and adjustments	-	-	-	-	-	-
Total original cost	763.6	207.8	2,194.2	313.9	456.5	3,936.0
Accumulated depreciation and amortization:						
Beginning balance	351.1	77.8	764.0	193.8	177.2	1,563.9
Increase in accumulated depreciation and amortization	15.1	4.5	65.1	15.1	13.8	113.6
Retirements	(26.5)	(0.6)	(16.5)	(9.6)	(11.5)	(64.7)
Retirement work-in-progress	(0.1)	(0.3)	(0.9)	-	-	(1.3)
Total accumulated depreciation and amortization	339.6	81.4	811.7	199.3	179.5	1,611.5
Ending balance	$ 424.0	$ 126.4	$ 1,382.5	$ 114.6	$ 277.0	$ 2,324.5

2013 *($ in millions)*	Hydroelectric Production	Transmission	Distribution	General	Intangible	Total
Original cost:						
Beginning balance	$ 714.7	$ 189.9	$ 1,966.9	$ 310.4	$ 411.5	$ 3,593.4
Capital acquisitions	59.5	13.3	121.5	10.0	29.6	233.9
Dispositions	(13.0)	(1.3)	(11.2)	(15.2)	(0.5)	(41.2)
Transfers and adjustments	-	-	9.2	-	-	9.2
Total original cost	761.2	201.9	2,086.4	305.2	440.6	3,795.3
Accumulated depreciation and amortization:						
Beginning balance	357.3	76.1	720.6	193.2	164.0	1,511.2
Increase in accumulated depreciation and amortization	14.0	4.4	61.1	16.1	13.7	109.3
Retirements	(20.4)	(2.7)	(17.9)	(15.5)	(0.5)	(57.0)
Retirement work-in-progress	0.2	-	0.2	-	-	0.4
Total accumulated depreciation and amortization	351.1	77.8	764.0	193.8	177.2	1,563.9
Ending balance	$ 410.1	$ 124.1	$ 1,322.4	$ 111.4	$ 263.4	$ 2,231.4

3. RATE STABILIZATION ACCOUNT

The Rate Stabilization Account (RSA) is a restricted cash reserve established to reduce the need for rapid and substantial rate increases solely to comply with the Department's bond covenants.

In March 2010 the Seattle City Council adopted Resolution No. 31187 and Ordinance No. 123260, establishing revised financial policies and parameters for the operation of the RSA created by Ordinance No. 121637 in 2004. Ordinance No. 123260 identified the sources of significant funding of the RSA and specified parameters for its operation. The RSA is to be drawn down to supplement revenues when surplus power sales revenues are below the budgeted amount, and conversely, deposits are to be made to the RSA when the surplus power sales revenues are greater than budgeted. Deposits or withdrawals may be made up to and including the date 90 days after the end of the applicable year.

Ordinance No. 123260 established a target size for the RSA of no less than $100.0 million and no greater than $125.0 million, and authorized the imposition of automatic temporary surcharges on electric rates when the RSA balance is within the below specified levels:

RSA Balance	Action
Less than or equal to $90.0 million but greater than $80.0 million	Automatic 1.5% surcharge
Less than or equal to $80.0 million but greater than $70.0 million	Automatic 3.0% surcharge
Less than or equal to $70.0 million but greater than $50.0 million	Automatic 4.5% surcharge
Less than or equal to $50.0 million	City Council must initiate rate review within 45 days and determine actions to replenish RSA to $100.0 million within 12 months

In February 2014 the Seattle City Council adopted Ordinance No. 124426 (retroactive to December 2013), directing specific cash transfers to the RSA with the intention of reducing the likelihood of future rate surcharges.

Ordinance No. 123260 originally required a rate review whenever the RSA balance exceeded $125.0 million, along with the implementation of measures to reduce the RSA balance to $125.0 million within a period of 12 months or less. Subsequently, the Seattle City Council adopted Ordinance No. 124108 in February 2013 (retroactive to January 1, 2013) which extended the timing of this required rate review and associated action to an effective date of January 1, 2014.

In 2014, actual surplus power sales revenues were greater than budgeted and funds of $3.4 million were transferred to the RSA from operating cash. Interest income of $1.0 million was earned on the RSA. Total net increase to the RSA was $4.4 million. The RSA balance was $114.4 million at December 31, 2014, and no surcharges were in effect during 2014.

In 2013, actual surplus power sales revenues were less than the budgeted surplus sales revenues and, accordingly, funds of $40.0 million were withdrawn from the RSA to supplement revenues. Interest income of $0.7 million was earned on the RSA. The estimated excess of operating cash to achieve in excess of 1.80x debt service coverage was $21.0 million and this amount was transferred to the RSA from operating cash in December 2013. Net 2013 RSA cash transferred to operating cash was $18.3 million. The RSA balance was $110.0 million at December 31, 2013, and no surcharges were in effect during 2013.

The RSA at December 31, 2014, and 2013, consisted of cash from the following sources:

($ in millions)	2014	2013
Rate Stabilization Account		
Beginning balance	$ 110.0	$ 128.3
RSA interest income	1.0	0.7
Operating revenue	3.4	(19.0)
Ending balance	$ 114.4	$ 110.0

RSA transactions are recorded in accordance with GASB Statement No. 62 *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements*.

The regulatory deferred inflow of resources Rate stabilization unearned revenue account at December 31, 2014, and 2013, consisted of the following:

($ in millions)	2014	2013
Unearned revenue - Rate Stabilization Account		
Beginning balance	$ 85.0	$ 103.3
RSA interest income	1.0	0.7
Operating revenue	3.4	(19.0)
Ending balance	$ 89.4	$ 85.0

The initial $25.0 million transfer from the Contingency Reserve Account to the RSA in May 2010 is not included in the Rate stabilization unearned revenue balance, and is not available to be transferred to current revenue in the event that net wholesale revenues are less than the budgeted amount. The Contingency Reserve Account was established in 2005 with proceeds that had been deposited in the Bond Reserve Fund, when the Bond Reserve Fund was replaced with a surety bond.

Transfers from/(to) the RSA in the statements of revenues, expenses and net position at December 31, 2014, and 2013 were as follows:

($ in millions)	2014	2013
Transfers from/(to) Rate Stabilization Account	$ (4.4)	$ 18.3

4. CASH AND EQUITY IN POOLED INVESTMENTS AND INVESTMENTS

Cash and Equity in Pooled Investments—Cash resources of the Department are combined with cash resources of the City to form a pool of cash that is managed by the City's Department of Finance and Administrative Services (FAS). Under the City's investment policy, all temporary cash surpluses in the pool are invested. The Department's share of the pool is included on the balance sheets as Cash and equity in pooled investments or as restricted assets. The pool operates like a demand deposit account in that all departments, including the Department, may deposit cash at any time and can also withdraw cash, out of the pool, up to the amount of the Department's fund balance, without prior notice or penalty. Accordingly, the statements of cash flows reconcile to cash and equity in pooled investments. The City considers investments in financial instruments having a maturity of 90 days or less as a cash equivalent.

Custodial Credit Risk of Deposits—Custodial risk is the risk that, in the event of bank failure for one of the City's depository institutions, the City's deposits may not be returned in a timely manner, or in the case of collateralized securities, the City may not be able to recover the collateral held in the possession of an outside party.

As of December 31, 2014 and 2013, the City did not have custodial risk. The City's deposits are covered by insurance provided by the Federal Deposit Insurance Corporation (FDIC) and the National Credit

Union Association (NCUA) as well as protection provided by the Washington State Public Deposit Protection Commission (PDPC) as established in the Revised Code of Washington (RCW) 39.58. The PDPC makes and enforces regulations and administers a program to ensure public funds deposited in banks and thrifts are protected if a financial institution becomes insolvent. The PDPC approves which banks, credit unions, and thrifts can hold state and local government deposits and monitors collateral pledged to secure uninsured public deposits. This secures public treasurers' deposits when they exceed the amount insured by the FDIC or NCUA by requiring banks, credit unions, and thrifts to pledge securities as collateral.

As of December 31, 2014 and 2013, the City held $95,000 in its cash vault. Additional small amounts of cash were held in departmental revolving fund accounts with the City’s various custodial banks, all of which fell within the NCUA and FDIC’s $250,000 standard maximum deposit insurance amount. Any of the City’s cash not held in its vault, or a local depository, was held in the City’s operating fund (investment pool), and at the close of every business day, any cash remaining in the operating fund is swept into an overnight repurchase agreement that matures the next day.

Investments—The Department’s cash resources may be invested by FAS separate from the cash and investments pool. Investments are managed in accordance with the City’s investment policy, with limits and restrictions applied at the City-wide level rather than to specific investments of the Department.

The City is authorized to purchase U.S. Treasury and government agency securities, certificates of deposits, and other investment deposits issued by Washington State depositories that qualify under the Washington State Deposit Protection Act as defined by RCW 39.58, bankers’ acceptances purchased in the secondary market, commercial paper purchased in the secondary market and having received the highest rating by at least two nationally recognized rating agencies, repurchase and reverse repurchase agreements with “primary dealers” that have executed master repurchase agreements, public funds in the Local Government Investment Pool (LGIP) in the State Treasury, and other securities as authorized by law.

The City of Seattle has the following policies in managing its investments:

- The City seeks to preserve principal while maximizing income and maintaining liquidity to meet the City’s need for cash.
- Investment decisions should further the City’s social policies established by ordinance or policy resolutions of the City Council.
- A City social policy shall take precedence over furthering the City’s financial objectives when expressly authorized by City Council resolution, except where otherwise provided by law or trust principles.
- Securities purchased shall have a maximum maturity of fifteen years, and the average maturity of all securities shall be less than five years.
- All transactions are executed on a delivery-versus-payment basis.
- The standard of prudence to be used by investment personnel shall be the “Prudent Person Rule” and will be applied in the context of managing an overall portfolio.

- Securities shall not be purchased with trading or speculation as the dominant criterion for the selection of the security.

Investments are recorded at fair value based on quoted market prices in accordance with Statement No. 31 of the GASB. Fair value is the amount at which a financial instrument could be exchanged in a current transaction between willing parties, other than in a forced or liquidation sale.

As of December 31, 2014 and 2013, the Department did not have any dedicated investments. The City's pool and other dedicated investments were as follows:

2014 *($ in millions)*	**Fair Value** City Pooled Investments	Other City Dedicated Pool	Total	**Weighted-Average Maturity (Days)**
Repurchase Agreements	$ 73.8	$ -	$ 73.8	2
U.S. Treasury and U.S. Government-Backed Securities	252.2	-	252.2 -	800
U.S. Government Agency Securities	550.3	-	550.3	1,208
U.S. Government Agency Mortgage-Backed Securities	171.4	-	171.4 -	2,054
Commercial Paper	319.4	-	319.4	44
Municipal Bonds	227.2	-	227.2	976
Non-negotiable CD	30.0	-	30.0	30
Total	$ 1,624.3	$ -	$ 1,624.3	
Weighted Average Maturity of the City's Pooled Investments				894

2013 *($ in millions)*	**Fair Value** City Pooled Investments	Other City Dedicated Pool	Total	**Weighted-Average Maturity (Days)**
Repurchase agreements	$ 44.8	$ -	$ 44.8	2
U.S. treasuries and U.S. government-backed securities	227.7	-	227.7	902
U.S. government agencies securities	666.8	-	666.8	880
U.S. government agency mortgage-backed securities	186.8	-	186.8	2,077
Commercial paper	155.0	-	155.0	47
Municipal bonds	156.8	-	156.8	818
Total	$ 1,437.9	$ -	$ 1,437.9	
Portfolio weighted-average maturity				915

As of December 31, 2014 and 2013, the Department's share of the City pool was as follows:

($ in millions)	2014	2013
Cash and equity in pooled investments:		
Restricted assets	$ 298.4	$ 227.0
Current assets	128.3	193.8
Total	$ 426.7	$ 420.8
Balance as a percentage of City pool	26.3 %	29.3 %

Fair Value of Pooled Investments— Fair value of the City's pooled investments fluctuates with changes in interest rates and the underlying size of the Pooled investment portfolio. To mitigate interest rate risk in the City's Pooled investment portfolio, the City typically holds its investments to maturity and manages its maturities to ensure sufficient monthly cash flow to meet its liquidity requirements. Through March 31, 2015, interest rates declined relative to December 31, 2014. The net change in the fair value of the City's Pooled investments, and thus the Department's share in the Pooled investments, increased favorably through the first quarter 2015 due in part to declining interest rates.

Interest Rate Risk—Interest rate risk is the risk that changes in interest rates over time will adversely affect the fair value of an investment. The City's investment policy limits the maturity of individual securities to fifteen years and limits the weighted average maturity of the total investment portfolio to no longer than five years which mitigates interest rate risk.

Credit Risk—Credit risk is the risk that an issuer or other counterparty to an investment will not fulfill its obligations. The City mitigates credit risk in several ways, as described below.

By state statutes and the City's investment policy, the City may purchase securities that carry the highest credit ratings issued by Moody's Investors Service, Standard & Poor's, and/or Fitch Ratings. Securities purchased must have the following ratings at the time of purchase: Securities backed by issuers with long-term credit ratings of Aaa, Aa1, and Aa2 by Moody's Investors Service; AAA, AA+, and AA by Standard & Poor's; and AAA, AA+, and AA by Fitch Ratings; and securities backed by issuers having short-term ratings of MIG1, VMIG1, and P1 by Moody's Investors Service; A1+ and A1 by Standard & Poor's; and F1+ and F1 by Fitch Ratings.

The City invests in U.S. Treasury securities which are considered free of credit risk, and in securities backed by the full faith and credit of the U.S. government, such as bonds issued by the Department of Housing and Urban Development (HUD). The City also invests in securities issued by U.S. government sponsored enterprises including Federal National Mortgage Association, Federal Home Loan Bank, and Federal Home Loan Mortgage Corporation.

Material credit risk in the City's investment portfolio resides in its holdings of commercial paper and municipal securities. In accordance with state statutes and the City's internal investment policy, the City manages that credit risk by purchasing securities backed by issuers having long-term and short-term credit ratings as noted above. The City also subscribes to asset-backed commercial paper research from Moody's Investors Service and Fitch Ratings, conducts internal due diligence of commercial paper and municipal issuers, and maintains an approved list of commercial paper issuers based upon internal and external credit research.

Concentration of Credit Risk—Concentration risk is the risk of loss attributed to the magnitude of investments in a single issuer. In accordance with the City's investment policy and state statutes that were in effect in 2014 and 2013, the City managed concentration risk by limiting its investments in any one issuer as follows:

- U.S Treasury bills, certificates, notes and bonds: 100% of the portfolio.
- U.S Government agency securities: 100% of the portfolio.
- Certificates of deposit: 25% of the portfolio and 10% of the portfolio per bank.
- Bankers' acceptances: 25% of the portfolio and 5% of the portfolio per bank.
- Commercial paper: 25% of the portfolio and 5% of the portfolio per issuer.
- Municipal bonds or warrants: 15% of the portfolio and 5% of the portfolio per issuer.
- Repurchase agreements: (1) Term and overnight - 50% of the portfolio, and (2) Term only (180 days) - 25% of the portfolio. All repurchase agreements were limited to 75% of Regulatory Capital (Regulated by Securities and Exchange Commission Rule 15C3-1) per dealer.
- Reverse repurchase agreements: 20% of the portfolio and 75% of Regulatory Capital per dealer.
- Mortgage backed securities: 15% of the portfolio.
- Local government investment pool: 110% of the portfolio.

At December 31, 2014 and 2013, the City did not have the following investments: bankers' acceptances, reverse repurchase agreements and local government investment pool.

The City's investments in single issuers, including those maturing less than one year from date of purchase, and amounting to 5% or more of the total portfolio as of December 31, 2014, and 2013, are shown in the following table.

($ in millions)	2014		2013	
Issuer	**Fair Value**	**Percent of Total Investments**	**Fair Value**	**Percent of Total Investments**
Federal Home Loan Mortgage Corporation (Freddie Mac)	$ 268.6	17 %	$ 329.4	23 %
Federal National Mortgage Association (Fannie Mae)	249.8	15	393.1	27
Federal Farm Credit Bank	121.7	7	-	-
Federal Home Loan Bank	81.7	5	86.5	6
Total	$ 721.8	44 %	$ 809.0	56 %

Custodial Credit Risk—Investments—The custodial credit risk for investments is the risk that in the event of failure of the counterparty, the City will not have access to, or be able to recover, its investments or collateral securities that are in the possession of an outside party. The City mitigates custodial credit risk for its investments by having its investment securities held by the City's contractual custodial agent, BNY Mellon, and not by the counterparty or the counterparty's trust department or agent. Additionally, the City mitigates custodial risk by settling its trades delivery-versus-payment through the City's contractual custodial agent.

By investment policy, the City maintains a list of approved securities dealers for transacting business. For repurchase agreements, the City transacts only with large primary dealers with investment grade credit ratings provided by at least two of the Nationally Recognized Statistical Rating Organizations (NRSROs). The City also conducts its own due diligence as to the financial wherewithal of its counterparties.

The City mitigates counterparty custodial risk from repurchase agreements by using a third-party custodian for tri-party repurchase agreements. The City conforms with industry standard requiring execution of a master repurchase agreement with each counterparty prior to transacting a repurchase agreement, execution of a third-party custodial agreement between the City, the broker, and the clearing bank, before transacting a third-party repurchase agreement, and over-collateralizing by a minimum of 102%. By investment policy, the underlying securities the City is willing to accept as collateral must have the highest credit ratings of at least two NRSROs. Throughout 2014 and 2013, the collateral underlying the City's repurchase agreements excluded securities other than U.S. Treasury, agencies, and agency mortgage-backed pass-throughs.

Foreign Currency Risk—The City Treasury pooled investment do not include securities denominated in in foreign currencies.

Reverse Repurchase Agreements—RCW 35.39.030 and City investment policy allow the investment of City monies in excess of current City needs in reverse repurchase agreements. However, at this time, the City does not engage itself in this type of investment strategy.

The City of Seattle's Comprehensive Annual Financial Report may be obtained by writing to The City of Seattle, Department of Finance and Administrative Services, P.O. Box 94680, Seattle, WA 98124-4689; telephone: (206) 684-2489, or obtained on-line at http:/www.seattle.gov/financial-services/comprehensive-annual-financial-report.

5. ACCOUNTS RECEIVABLE

Accounts receivable at December 31, 2014 and 2013, consist of:

($ in millions)	Retail Electric	Wholesale Power	Other Operating	Operating Subtotal	Nonoperating Subtotal	Total
2014						
Accounts receivable	$ 42.3	$ 14.8	$ 9.9	$ 67.0	$ 13.8	$ 80.8
Less allowance for doubtful accounts	(2.8)	-	(4.9)	(7.7)	-	(7.7)
	$ 39.5	$ 14.8	$ 5.0	$ 59.3	$ 13.8	$ 73.1
2013						
Accounts receivable	$ 42.4	$ 8.9	$ 10.2	$ 61.5	$ 11.1	$ 72.6
Less allowance for doubtful accounts	(3.5)	-	(5.9)	(9.4)	-	(9.4)
	$ 38.9	$ 8.9	$ 4.3	$ 52.1	$ 11.1	$ 63.2

Wholesale power receivable includes $1.6 million at December 31, 2014, and $2.8 million at December 31, 2013, for exchange energy at fair value under long-term contracts (see Note 15 Long-Term Purchased Power, Exchanges, and Transmission).

6. OTHER ASSETS

Seattle City Council passed resolutions authorizing debt financing and reporting as regulatory assets certain costs in accordance with Statement No. 62 of the GASB, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB & AICPA Pronouncements*. Programmatic conservation costs incurred by the Department and not funded by third parties and Endangered Species Act costs are reported as regulatory assets in accordance with Statement No. 62 and amortized over 20 years. Endangered Species Act costs are amortized over the remaining license period (see Note 16 Commitments and Contingencies). Environmental costs reported as regulatory assets are amortized over 25 years, beginning in the year costs are paid.

Other assets, which are not covered under Statement No. 62, consist of:

- Suburban infrastructure long-term receivables are underground electrical infrastructure costs for suburban jurisdictions, which are recovered through rates from customers within the respective jurisdictions for a period of approximately 25 years, as approved by the Seattle City Council.
- Long-term interfund receivable for expected recoveries related to environmental costs covered under GASB Statement No. 49, *Accounting and Financial Reporting for Pollution Remediation Obligations* (see Note 11 Environmental Liabilities).
- Puget Sound Energy interconnection and substation costs are being amortized to expense over 25 years.
- Studies, surveys, and investigations are reported as regulatory assets until such time they result in active projects, or when it is determined no assets will result, at which time they are expensed.

- Long-term customer loans receivable and the remaining components of other assets, are not amortized.

Regulatory assets and other assets, net, at December 31, 2014 and 2013, consisted of the following:

($ in millions)	2014	2013
Regulatory assets:		
Conservation costs—net	$ 228.1	$ 214.3
Endangered Species Act costs—net	2.2	2.3
Environmental costs	34.5	31.7
	264.8	248.3
Other charges and assets—net:		
Suburban infrastructure long-term receivables	43.1	44.0
Long-term interfund receivable for environmental costs	4.1	3.1
Long-term customer notes receivable	0.7	0.8
Puget Sound Energy interconnection and substation	0.6	0.7
Studies, surveys, and investigations	2.8	2.8
Other	3.6	1.3
	54.9	52.7
Total Other Assets	$ 319.7	$ 301.0

7. LONG-TERM DEBT

At December 31, 2014 and 2013, the Department's long-term debt consisted of the following prior lien or parity bonds:

LONG-TERM
($ in millions)

		Fixed Rate	Maturity Year	Original Issuance	2014	2013
Prior Lien Bonds:						
2014	ML&P Improvement and Refunding Revenue Bonds	4.000%–5.000%	2044	$ 265.2	$ 265.2	$ -
2013	ML&P Improvement and Refunding Revenue Bonds	2.000%–5.000%	2043	190.8	187.7	190.8
2012A	ML&P Improvement and Refunding Revenue Bonds	2.000%–5.000%	2041	293.3	284.8	289.5
2012B	ML&P Refunding Revenue Bonds	0.350%–0.700%	2014	9.3	-	4.8
2012C	ML&P Clean Renewable Energy Bonds	3.400%–3.750%	2033	43.0	43.0	43.0
2011A	ML&P Improvement and Refunding Revenue Bonds	1.000%–5.500%	2036	296.3	266.0	278.0
2011B	ML&P Clean Renewable Energy Bonds	5.750%–5.750%	2027	10.0	10.0	10.0
2010A	ML&P Build America Bonds	4.447%–5.570%	2040	181.6	181.6	181.6
2010B	ML&P Improvement and Refunding Revenue Bonds	2.000%–5.000%	2026	596.9	466.4	510.1
2010C	ML&P Recovery Zone Economic Development Bonds	5.590%–5.590%	2040	13.3	13.3	13.3
2008	ML&P Revenue and Refunding Revenue Bonds	4.000%–6.000%	2029	257.4	185.8	201.1
2004	ML&P Improvement and Refunding Revenue Bonds	3.000%–5.250%	2029	284.9	-	141.1
Total prior lien bonds				$ 2,442.0	$ 1,903.8	$ 1,863.3

The Department had the following activity in long-term debt during 2014 and 2013:

($ in millions)	Balance at 1/1/14	Additions	Reductions	Balance at 12/31/14	Current Portion
2014					
Prior Lien Bonds	$ 1,863.3	$ 265.2	$ (224.7)	$ 1,903.8	$ 104.9

	Balance at 1/1/13	Additions	Reductions	Balance at 12/31/13	Current Portion
2013					
Prior Lien Bonds	$ 1,778.6	$ 190.7	$ (106.0)	$ 1,863.3	$ 99.7

Prior Lien Bonds—In November 2014 the Department issued $265.2 million of tax exempt Municipal Light and Power (ML&P) Improvement and Refunding Revenue Bonds (2014 Bonds). Coupon interest rates range from 4.00% to 5.00% and mature serially from September 1, 2015 to September 1, 2038 with term Bonds maturing September 1, 2044. The arbitrage yield of the 2014 Bonds was 2.58%. Arbitrage yield, when used in computing the present worth of all payments of principal and interest on the Bonds in the manner prescribed by the Internal Revenue Code, produces an amount equal to the issue price of the Bonds. Proceeds from the 2014 Bonds are being used to finance certain capital improvement and conservation programs, to advance refund $125.0 million of the 2004 series outstanding prior lien bonds, and to make a deposit to the Reserve Fund.

The debt service on the 2014 Bonds requires a cash flow over the life of the bonds of $414.4 million, including $149.2 million in interest. The difference between the cash flows required to service the old and new debt and to complete the refunding totaled $20.5 million, and the aggregate economic gain on refunding totaled $19.0 million at net present value. The accounting loss on refunding was $1.3 million.

In July 2013 the Department issued $190.8 million of tax exempt Municipal Light and Power (ML&P) Improvement and Refunding Revenue Bonds (2013 Bonds). Coupon interest rates range from 2.00% to 5.00% and mature serially from July 1, 2014 to July 1, 2033 with term Bonds maturing July 1, 2043. The arbitrage yield of the 2013 Bonds was 3.91%. Proceeds from the 2013 Bonds were used to finance certain capital improvement and conservation programs, to advance refund $14.2 million of the 2004 series outstanding prior lien bonds, and to make a deposit to the Reserve Fund.

The debt service on the 2013 Bonds requires a cash flow over the life of the bonds of $352.2 million, including $161.4 million in interest. The difference between the cash flows required to service the old and new debt and to complete the refunding totaled $1.4 million, and the aggregate economic gain on refunding totaled $0.7 million at net present value. The accounting loss on refunding was $0.8 million.

The Department has certain bonds outstanding that provide a refundable tax credit, or federal subsidy, paid to state or local governmental issuers by the United States Internal Revenue Service. The amount of the federal subsidy is equal to the lesser of the amount of interest payable based on the coupon interest rate or a percentage of the amount of interest payable based on the tax credit rate on the sale date with respect to those bonds. This federal subsidy ultimately results in a net decrease to debt service, although debt service payments are paid gross. The federal subsidies are recorded as nonoperating revenues on the statements of revenues, expenses, and changes in net position.

Pursuant to the requirements of the Balanced Budget and Emergency Deficit Control Act of 1985, as amended, certain automatic reductions were effective March 1, 2013 for qualified bonds including the Department's 2012C series Bonds, 2011B series Bonds, 2010A series Bonds, and 2010C series Bonds. Federal subsidies for these bonds were reduced by 7.2% through the end of the federal fiscal year

(September 30, 2014) at which time the automatic reductions were adjusted to 7.3%. The effect for the accrual of federal subsidies as of December 31, 2014 was inconsequential. The effect during 2015 is estimated to be lower federal subsidies by approximately $0.4 million. The effect thereafter for federal subsidies is indeterminable.

Debt service requirements for prior lien bonds, excluding federal subsidies for the 2012, 2011 and 2010 bonds are as follows:

Years Ending December 31 *($ in millions)*	**Principal Redemptions**	**Interest Requirements**	**Total**
2015	$ 104.9	$ 89.5	$ 194.4
2016	101.6	86.4	188.0
2017	102.8	81.3	184.1
2018	103.4	76.4	179.8
2019	100.2	71.4	171.6
2020 – 2024	500.9	281.6	782.5
2025 – 2029	358.1	166.1	524.2
2030 – 2034	208.7	100.8	309.5
2035 – 2039	208.6	49.4	258.0
2040 – 2044	114.6	10.8	125.4
Total	$ 1,903.8	$ 1,013.7	$ 2,917.5

The Department is required by Ordinance No. 124336 (the bond ordinance) to fund reserves for the 2014 Bonds and other parity bonds in the Municipal light and power bond reserve fund (Reserve Fund) in an amount at any time equal to the lesser of (a) the maximum annual debt service on all parity bonds then outstanding; and (b) the maximum amount permitted by the Internal Revenue Code as a reasonably required reserve or replacement fund (Reserve Requirement). The Reserve Requirement upon issuance of the 2014 Bonds was an amount equal to $114.4 million (125% of average annual debt service). The maximum annual debt service on prior lien bonds is $194.4 million due in 2015 and the average annual debt service was $91.5 million at issuance of the 2014 Bonds. The Reserve Requirement is funded in part with a Reserve Fund (an account within the books of the Department) with a balance of $47.9 million at the end of 2014. Funding of the Reserve Fund is comprised of bond proceeds, operating cash transfers, and interest earnings. The Reserve Requirement was also funded by an existing surety bond purchased in 2005 from Financial Security Assurance, Inc., which is now known as Assured Guarantee Municipal Corporation, in the amount of $77.1 million. The surety bond will expire on August 1, 2029. As of December 31, 2014, Assured Guarantee Municipal Corporation was rated A2 and AA by Moody's and Standard & Poor's, respectively. The bond ordinance does not require that the Reserve Requirement be funded with cash, a substitute surety bond, or letter of credit, if the provider of qualified insurance is downgraded. Under the bond ordinance, a surety bond qualifies as Qualified Insurance for purposes of satisfying the Reserve Requirement if the provider's ratings are in one of the top two rating categories at the time the policy is issued, even if the provider of such surety bond is subsequently downgraded.

A portion of the proceeds from the 2014 revenue refunding Bonds were placed in a separate irrevocable trust account to provide for all future debt service payments on certain prior lien bonds advance refunded or defeased. Neither the assets of the trust account nor the liabilities for the defeased bonds are reflected in the Department's financial statements. There was no outstanding principal balance of defeased bonds as of December 31, 2014, and $41.8 million of defeased bonds were outstanding as of December 31, 2013. Also, $121.4 million of the 2003 bonds were repaid from the 2013 irrevocable trust account during 2013. There were no irrevocable trust account assets at the end of December 31, 2014.

Bond Ratings—The 2014 and 2013 Bonds, along with other outstanding parity bonds, were rated "Aa2" and "AA"; and "Aa2" and "AA", by Moody's Investors Service, Inc. and Standard Poor's Rating Services, respectively.

Revenue Pledged—Revenue bonds are special limited obligations payable from and secured solely by the gross revenues of the Department, less charges for maintenance and operations, and by money in the debt service account and Reserve Fund. Principal and interest paid for 2014 and 2013 was $189.9 million and $178.0 million, respectively. Total revenue available for debt service as defined for the same periods was $341.4 million and $319.6 million, respectively. Annual interest and principal payments are expected to require 56.9% of revenues available for debt service for 2015 and required 59.4% in 2014.

Federal Arbitrage Regulations—Revenue bonds are subject to federal arbitrage regulations and the Department has complied with these regulations. There was no federal arbitrage rebate due in 2014 or 2013.

Other—There were no liens on property or revenue pertaining to parity bonds and all bond covenants were in compliance for the Department's prior lien bonds as of December 31, 2014 and 2013, respectively.

Fair Value—Fair values at December 31, 2014 and 2013 were provided by the Department's financial advisor, Piper Jaffray & Company. The fair value for the Department's bonds are estimated based on the quoted market prices for the same or similar issues or on the current rates offered to the Department for debt of the same remaining maturities. Carrying amounts (net of premiums and discounts) and fair values at December 31, 2014 and 2013, were as follows:

($ in millions)	2014		2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt:				
Prior lien bonds	$ 2,030.1	$ 2,145.2	$ 1,970.0	$ 2,012.6

Amortization—Discounts and premiums are amortized using the effective interest method over the term of the bonds.

The excess of costs incurred over the carrying value of bonds refunded on early extinguishment of debt is amortized as a component of interest expense using the effective interest method over the terms of the issues to which they pertain. Charges on advance refunding amortized to interest expense totaled $3.8 million in 2014 and $4.2 million in 2013. Charges on advance refunding in the amount of $19.3 million and $26.0 million are included as a component of Deferred Outflows of Resources on the 2014 and 2013 balance sheets, respectively.

Noncurrent Liabilities—The Department had the following activities during 2014 and 2013:

($ in millions)	Balance at 1/1/14	Additions	Reductions	Balance at 12/31/14
2014				
Accumulated provision for injuries and damages	$ 54.9	$ 0.3	$ (12.3)	$ 42.9
Compensated absences	15.5	1.2	-	16.7
Other	7.7	-	-	7.7
Total	$ 78.1	$ 1.5	$ (12.3)	$ 67.3

	Balance at 1/1/13	Additions	Reductions	Balance at 12/31/13
2013				
Accumulated provision for injuries and damages	$ 53.5	$ 1.4	$ -	$ 54.9
Compensated absences	15.1	0.4	-	15.5
Other	6.2	1.5	-	7.7
Total	$ 74.8	$ 3.3	$ -	$ 78.1

Additional information about the provision for injuries and damages can be found in Note 8 Provision for Injuries and Damages, and Note 11 Environmental Liabilities. Other includes primarily a liability for Other Postemployment Benefits; see Note 10 Seattle City Employees' Retirement System and Other Postemployment Benefits.

8. PROVISION FOR INJURIES AND DAMAGES

The Department establishes liabilities for claims based on estimates of the ultimate projected cost of claims. Environmental related expenses are discussed in Note 11 Environmental Liabilities. The length of time for which such costs must be estimated varies depending on the nature of the claim. Actual claims costs depend on such factors as inflation, changes in doctrines of legal liability, damage awards, and specific incremental claim adjustment expenses. Claims liabilities are recomputed periodically using actuarial and statistical techniques to produce current estimates, which reflect recent settlements, claim frequency, industry averages, City-wide cost allocations, and economic and social factors. For 2014 and 2013, liabilities for lawsuits, claims, and workers' compensation were discounted over a period of 16 to 19 years at the City's average annual rate of return on investments, which was 0.931% and 0.675%, respectively.

To address the risk for certain losses arising from personal and property damage claims by third parties and for job-related illnesses and injuries to employees, the Department as part of the City of Seattle, has been self-insured for most of its general liability risks, for workers' compensation, and for employees' health care benefits. Beginning April 1, 2014, the City had general liability insurance coverage for losses over a $6.5 million self-insured retention per occurrence, with a $60.0 million limit per occurrence and in the aggregate. The Department had no settled claims exceeding coverage in the last three years.

The City also purchased an all risk comprehensive property insurance policy that provides $500.0 million in limits subject to various deductible levels depending on the type of asset and value of the building. This includes $100.0 million in earthquake and flood limits. Hydroelectric and certain other utility producing and processing projects are not covered by the property policy. The City also purchased insurance for excess workers' compensation, fiduciary and crime liability, inland marine transportation, volunteers, and an assortment of commercial general liability, medical, accidental death and dismemberment, and miscellaneous policies. Bonds are purchased for public officials, public notaries, pension exposures, and specific projects and activities as necessary.

The changes in the provision for injuries and damages at December 31, 2014, and 2013, are as follows:

($ in millions)	2014	2013
Beginning unpaid claims liability	$ 11.7	$ 11.5
Payments	(3.1)	(5.0)
Incurred claims	4.3	5.2
Ending unpaid claims liability	$ 12.9	$ 11.7

The provision for injuries and damages included in current and noncurrent liabilities at December 31, 2014, and 2013 is as follows:

($ in millions)	2014	2013
Noncurrent liabilities	$ 8.9	$ 8.6
Accounts payable and other current liabilities	4.0	3.1
Total liability	$ 12.9	$ 11.7

9. ACCOUNTS PAYABLE

Accounts Payable and Other Current Liabilities—The composition of accounts payable and other current liabilities at December 31, 2014 and 2013, are as follows:

($ in millions)	2014	2013
Vouchers payable	$ 38.4	$ 33.0
Power accounts payable	22.6	23.8
Taxes payable	7.8	10.5
Claims payable	27.7	17.1
Guarantee deposit and contract retainer	2.5	3.5
Other accounts payable	2.3	2.8
Total	$ 101.3	$ 90.7

10. SEATTLE CITY EMPLOYEES' RETIREMENT SYSTEM AND OTHER POSTEMPLOYMENT BENEFITS

Pension Benefits—The Seattle City Employees' Retirement System (SCERS) is a single-employer defined benefit public employee retirement system, covering employees of the City and administered in accordance with Chapter 41.28 of the Revised Code of Washington and Chapter 4.36 of the Seattle Municipal Code. SCERS is a pension trust fund of the City.

All employees of the City are eligible for membership in SCERS with the exception of uniformed police and fire personnel who are covered under a retirement system administered by the State of Washington. Employees of the King County Departments of Transportation and Public Health who established membership in SCERS when these organizations were City departments were allowed to continue their SCERS membership. As of December 31, 2014, there were 6,020 retirees and beneficiaries receiving benefits and 8,746 active members of SCERS. In addition, 1,188 vested terminated employees were entitled to future benefits.

SCERS provides retirement, death, and disability benefits. Retirement benefits vest after 5 years of credited service, while death and disability benefits vest after 10 years of credited service. Retirement benefits are calculated as 2% multiplied by years of creditable service, multiplied by average salary, based on the highest 24 consecutive months, excluding overtime. The benefit is actuarially reduced for early retirement. Additional increases in the cost-of-living adjustments are available to current and future retired members only if SCERS attains at least a 100% funding ratio. SCERS does not provide termination benefits.

The contribution requirements of plan members and the City are established and may be amended by the Seattle City Council. In November 2010, the City Council adopted Ordinance No. 123482, amending Seattle Municipal Code Section 4.36.110 to provide for contribution rate increases for members of the City's Retirement System. In November 2011, the Seattle City Council adopted Resolution No. 31334, affirming the City's intent to fully fund its required contributions to SCERS. Changes to contribution rates are necessary to ensure continued financial support to the retired employees of the City. The City is required to contribute at an actuarially determined rate, equal to at least that of the members' contribution rate.

The City's contracts with all labor unions that represent members of SCERS describe how contribution rates would be changed in the event higher contributions are needed to improve the financial status of the Employee's Retirement Fund. Under these contracts, the City and employees will share any contribution rate increase equally, up to a maximum increase of 2% in the employee contribution. If a contribution rate increase is needed, the City intends to apply the same formula to non-represented employees.

Effective January 2012, the employee contribution rate of annual covered payroll was increased from 9.03% to 10.03%. The employer contribution rate was increased from 9.03% to 11.01%. The increase in contribution rates was necessary to acknowledge the financial and economic recession of 2007/2008 which adversely impacted SCERS' assets. Also, plan demographics showed active members in SCERS retire later in life and live longer, placing a heavier liability on SCERS' assets.

In 2013, the total contribution rate was met with an employee contribution rate of 10.03% and in accordance with Resolution No. 31334, the City's contribution rate was increased from 11.01% to 12.89%. In 2014, the City's contribution rate was increased from 12.89% to 14.31% for a total combined contribution rate of 24.34% in accordance with Resolution No. 31474 adopted in August 2013.

In September 2014, the City Council adopted Resolution No. 31540, amending Resolution No. 31474, and increasing the City's contribution rate from 14.31% to 15.73% for a total contribution rate of 25.76% effective 2015, to reflect the results of the January 1, 2014 actuarial valuation study. This reflects the City's commitment to fund the actuarial required contribution rate.

Resolution No. 31474 clarified the City's approach toward amortizing the unfunded liability of SCERS and requested that the SCERS Board of Administration and its actuary deliver to the City Council in 2014 an analysis of other potential assumption and policy changes designed to further strengthen the retirement system. Resolution No. 31474 ended the rolling amortization practice that was effective with the January 1, 2013 actuarial valuation and revised the amortization period to amortize the UAAL to 29 years. Previously, the January 1, 2013 actuarial valuation required amortization for the unfunded liability as a closed, fixed period of 30 years. The change was retro-active to January 1, 2013.

Under the authority of the state and City, SCERS operates a securities lending program, and there were transactions during 2014 and 2013. In 2014 and 2013, SCERS did not incur a loss as a result of borrower default. SCERS did not have negative credit exposure at December 31, 2014, or 2013.

Employer contributions for the City were $89.8 million, $76.6 million, and $62.5 million in 2014, 2013, and 2012, respectively. Employer contributions for the Department were $22.0 million, $18.4 million, and $15.1 million in 2014, 2013, and 2012, respectively.

Actuarial Data

Valuation date	January 1, 2014
Actuarial cost method	Entry age
Amortization method	Level percent
Remaining amortization period	29 years*
Amortization period	Maximum of 30 years
Asset valuation method	5-Year Smoothing

Actuarial Assumptions*

Price inflation	3.25%
Investment rate of return	7.50%
Projected general wage increases	4.00%
Postretirement benefit increases	1.50%
Cost-of-living year-end bonus dividend	0.00%

* The revised contribution rate of 24.34% currently in effect as of the January 1, 2014 valuation.

Annual Pension Cost and Net Pension Obligation

For Fiscal Years Ending December 31, 2014 and December 31, 2013

Based on January 1, 2013 and January 1, 2012 Valuations*

	($ in millions)	Fiscal Year Ended December 31 2014	2013
1a	Total normal cost rate	14.95 %	14.95 %
1b	Employee contribution rate	10.03 %	10.03 %
1c	Employer normal cost rate (1a-1b)	4.92 %	4.92 %
2a	Total employer contribution rate	14.31 %	12.89 %
2b	Amortization payment rate (2a-1c)	9.39 %	7.97 %
2c	Amortization period**	35 years	38 years
2d	GASB 27 amortization rate	10.68 %	9.10 %
3	Total annual required contribution (ARC) rate (1c+2d)	15.60 %	14.02 %
4	Covered employee payroll***	$ 598.0	$ 567.8
5a	ARC (3x4)****	$ 83.9	$ 67.2
5b	Interest on net pension obligation (NPO)	(0.2)	(0.6)
5c	ARC adjustment	0.1	0.4
5d	Annual pension cost (APC) (5a+5b+5c)	$ 83.8	$ 67.0
6	Employer contribution	$ 77.1	$ 62.5
7a	Change in NPO (5d-6)	$ 6.7	$ 4.5
7b	NPO at beginning of year	(2.6)	(7.1)
7c	NPO at end of year (7a+7b)	$ 4.1	$ (2.6)

* Beginning with the January 1, 2013 actuarial valuation report, GASB calculations take into account the lag between determination of the actuarial contribution rate. For example, the January 1, 2012 actuarial valuation calculates the contribution rate beginning January 1, 2013 (for fiscal year ending December 31, 2013). This change was made due to SCERS' new funding policy, adopted in 2011, to contribute the actuarially determined contribution rate (previously, a fixed rate was contributed).

** If the amortization period determined by the actual contribution rate exceeds the maximum amortization period required by GASB Statement No. 27, the ARC is determined using an amortization of the UAAL over 30 years.

*** Covered payroll includes compensation paid to all active employees on which contributions were made in the year preceding the valuation date.

**** Items 5a-5d were calculated using prior year total ARC rate. In 2012, total ARC rate was 11.84%.

The schedules of funding progress ($ in millions) (unaudited) for SCERS are as follows:

Actuarial Valuation Date January 1	Actuarial Value of Assets (A)	Actuarial Accrued Liabilities (AAL)[a] (B)	Unfunded AAL (UAAL)[b] (B-A)	Funding Ratio (A/B)	Covered Payroll[c] (C)	UAAL (or Excess) as a Percentage of Covered Payroll ((B-A)/C)
2012	$ 1,954.3	$ 2,859.3	$ 905.0	68.3 %	$ 557.0	162.5 %
2013	1,920.1	3,025.3	1,105.2	63.5	567.8	194.6 %
2014	2,094.3	3,260.1	1,165.8	64.2	597.9	195.0 %

(a) Actuarial present value of benefits less actuarial present value of future normal costs based on entry age actuarial cost method.
(b) Actuarial accrued liabilities less actuarial value of assets; funding excess if negative.
(c) Covered payroll includes compensation paid to all active employees on which contributions were made in the year preceding the valuation date.

SCERS issues stand-alone financial statements that may be obtained by writing to the Seattle City Employees' Retirement System, 720 Third Avenue, Suite 900, Seattle, WA 98104; by telephone at (206) 386-1293; or by accessing the web site http://www.seattle.gov/retirement/annual_report.htm.

Other Postemployment Benefits (OPEB)—Health care plans for active and retired employees are administered by the City of Seattle as single-employer defined benefit public employee health care plans.

Employees retiring under the City may continue their health insurance coverage under the City's health insurance plans for active employees. When a retired participant dies, the spouse remains fully covered until age 65 and covered by the Medicare supplement plan thereafter. Employees that retire with disability retirement under the City may continue their health coverage through the City with same coverage provisions as other retirees. Eligible retirees self-pay 100 percent of the premium based on blended rates which were established by including the experience of retirees with the experience of active employees for underwriting purposes. The City provides an implicit subsidy of the post-retirement health insurance costs and funds the subsidy on a pay-as-you-go basis. The postemployment benefit provisions are established and may be amended by ordinance of the Seattle City Council and as provided in Seattle Municipal Code 4.50.020.

The City's expected contribution for employer-paid benefits was $1.0 million, $2.4 million, and $2.4 million in 2014, 2013, and 2012, respectively. The Department's portion of the expected contribution was $0.2 million, $0.4 million, and $0.4 million in years 2014, 2013 and 2012, respectively. The City recorded an expense and liability for OPEB of $2.5 million in 2014 and $4.8 million in 2013. The Department recorded a reduction to an expense and liability for OPEB of $13.1 thousand in 2014, and an increase to an expense and liability for OPEB of $1.5 million in 2013.

Actuarial valuations involve estimates of the value of reported amounts and assumptions about the probability of events far into the future. Actuarially determined amounts are subject to continual revision as actual results are compared to past expectations and new estimates are made about the future.

Calculations are based on the types of benefits provided under the terms of the substantive plan at the time of each valuation and on the pattern of sharing of costs between the employer and plan members to that point. The projection of benefits for financial reporting purposes does not explicitly incorporate the potential effects of legal or contractual funding limitations on the pattern of cost sharing between the employer and plan members in the future. Actuarial calculations reflect a long-term perspective. Consistent with that perspective, actuarial methods and assumptions used include techniques that are designed to reduce short-term volatility in actuarial accrued liabilities and the actuarial value of assets. Based on the latest biennial actuarial valuation date the significant methods and assumptions are as follows:

Actuarial data and assumptions

Valuation date	January 1, 2014
Actuarial cost method	Entry age normal
Amortization method	Level dollar
Initial amortization period	30 years, open
Discount rate	3.48%
Health care cost trend rates—medical:	Aetna plans: 8.0%, decreasing by 0.5% each year for 2 years with varying rate changes thereafter. Group Health plans: 7.5%, decreasing by 0.5% each year for 3 years with varying rate changes thereafter.
Participation	40% of Active Employees who retire participate
Mortality	General Service Actives and Retirees based on RP-2000 Table and RP-2000 Combined Healthy, respectively, with ages set back six years for male and female actives; set back two years for male and female reitrees. Rates are generational for both males and females using Projection Scale AA.
Marital status	45% of members electing coverage: married or have a registered domestic partner. Male spouses two years older than their female spouses.
Morbidity factors	Morbidity rate ranges for ages 50 through 64:
Aetna Traditional & Aetna Preventive	Per-capita claim costs for the two Aetna plans were developed based on a blending of the following with equal weights (25% each): self-funding premium equivalent rates provided by City of Seattle, Aon Hewitt's internal manual rate, retiree claim experience specific to each plan from 1/1/2012 to 8/31/2014, and active claim experience specific to the Aetna plans from 1/1/2012 to 8/31/2014. For the Aetna plans, because the retirees' spouses pay a lower premium for health care coverage than retirees, the net cost to the City for the spouse coverage is greater than for a retiree of the same age and gender. The morbidity factors were adjusted to reflect this discrepancy.
Group Health Standard and Deductible Plans	Per-capita claim costs for the two Group Health plans were developed based on a blending of the following with equal weights (33.3% each): self-funding premium equivalent rates provided by City of Seattle, Aon Hewitt's internal manual rate, and retiree claim experience specific to each plan from 1/1/2012 to 8/31/2014.
Other considerations	Active employees with current spouse and/or dependent coverage elect same plan and coverage. After retirement, it is assumed that children will have aged off of coverage and will have $0 liability.

Based on the actuarial valuation date of January 1, 2014, the City's annual cost for fiscal years ended

December 31, 2014 and 2013, the amount of expected contribution to the plan, and changes in net obligation are as follows:

($ in millions)	**2014**	**2013***
Annual required contribution	$ 4.4	$ 8.5
Interest on net OPEB obligation	1.5	1.5
Adjustment to annual required contribution	(2.4)	(2.2)
Annual OPEB cost (expense)	3.5	7.8
Expected contribution (employer-paid benefits)	(1.0)	(3.0)
Increase in net OPEB obligation	2.5	4.8
Net OPEB obligation - beginning of the year	44.3	39.5
Net OPEB obligation - end of year	$ 46.8	$ 44.3

* Updated based on the latest actuarial valuation report dated January 1, 2014.

The schedules of funding progress ($ in millions) (unaudited) are as follows:

Actuarial Valuation Date January 1	**Actuarial Value of Assets (A)**	**Actuarial Accrued Liabilities (AAL) Entry Age (B)**	**Unfunded AAL (UAAL) (B-A)**	**Funding Ratio (A/B)**	**Covered Payroll (C)**	**UAAL as a Percentage of Covered Payroll ((B-A)/C)**
2012	$ -	$ 74.7	$ 74.7	- %	$ 891.6	8.4 %
2013	-	78.9	78.9	-	936.1	8.4
2014	-	41.8	41.8	-	1,004.0	4.2

The Health Care Subfund of the General Fund is reported in The City of Seattle's Comprehensive Annual Financial Report.

11. ENVIRONMENTAL LIABILITIES

Environmental liabilities were $57.6 million and $60.2 million, at December 31, 2014, and 2013, respectively.

The following is a brief description of the significant Superfund sites:

● *The Harbor Island Superfund Site*—In 1983, the U.S. Environmental Protection Agency (EPA) designated this site as a federal Superfund site. The Department and other entities are sharing costs of investigating contamination in the East Waterway alongside Harbor Island. The Department's involvement stems from its sale of transformers to a company on Harbor Island. The City of Seattle is one of four parties who are conducting a remedial investigation and feasibility study that will delineate cleanup actions. The EPA approved the remedial investigation report. The Department's ultimate liability is indeterminate.

● *The Lower Duwamish Waterway Superfund Site*—In 2001, the EPA designated this site as a federal Superfund site for contaminated sediments. The Department's involvement is attributable to its land ownership or use of property along the river. The City of Seattle is one of four parties who signed an Administrative Order on Consent (AOC) with the EPA and Washington State Department of Ecology to conduct a remedial investigation/feasibility study to prepare a site remedy. The EPA approved the feasibility study in November 2012. In February 2013, the EPA issued the Proposed Plan for cleanup of the Lower Duwamish Waterway Superfund Site. In November 2014, the EPA issued its final Record of Decision indicating its preferred alternative clean-up with an estimated cost of $342.0 million. At this time, the cost of certain additional undefined requirements by the EPA is unknown. The Department's ultimate liability is indeterminate.

In November 2012, the EPA issued general notification letters to parties informing them of their potential liability for the Lower Duwamish Waterway cleanup. The City and other three parties who signed the AOC with the EPA have agreed to invite some of those parties to participate in an alternative dispute resolution process (the "allocation process") to resolve their respective shares of past and future costs. The City has selected an allocator. The development of the allocation process agreement is ongoing. The Department has agreed to administer the allocator's contract. Parties participating in the allocation process will share the cost of the allocator and the process.

The City is also responsible for investigation and cleanup at the Port of Seattle Terminal 117. The City agreed to pay 40% of the costs to clean up the uplands and river sediment parts of the site and 100% of the costs to clean up contamination in adjacent streets. The City's share for the uplands and sediments is paid 100% by the Department and the Department's ultimate liability is indeterminate for Terminal 117.

● *North Boeing Field/Georgetown Steam Plant*—The City, King County, and Boeing have signed an Administrative Order issued by the Washington State Department of Ecology (Ecology) requiring them to investigate and possibly remove contamination in an area that encompasses North Boeing Field, the Department's Georgetown Steam Plant, and the King County Airport. This site was also the subject of the lawsuit brought by the City against Boeing. Boeing has agreed to pay 67% of the costs for Ecology's implementation of the order. The order requires completion and then implementation of a remedial investigation/feasibility study work plan. The final remedial investigation work plan was issued in November 2013. In January 2015, all parties executed the First Amendment to the North Boeing Field/Georgetown Steam Plant Agreed Order, making all parties responsible for conducting and completing remedial action at the site. The City is responsible for 1/3 of the costs, with the Department's share at 90%. The implementation of the work plan is scheduled for 2015. Boeing and the City will each pay 100% of costs for remedial action at their own facilities.

The Department has included in its estimated liability those portions of the environmental remediation work that are currently deemed to be reasonably estimable. Cost estimates were developed using the expected cash flow technique in accordance with Statement No. 49 of the GASB. Estimated outlays were based on current cost and no adjustments were made for discounting or inflation. Cost scenarios were developed that defined a particular solution for a given site. Scenarios considered relevant potential requirements and alternatives for remediation of a site. Costs were calculated on a weighted average that was based on the probabilities of each scenario being selected and reflected cost-sharing agreements in effect. In addition, certain estimates were derived from independent engineers and consultants. The estimates were made with the latest information available; as new information becomes available, estimates may vary significantly due to price increases or reductions, technology, or applicable laws or regulations.

The Department is aggressively pursuing other third parties that may have contributed to the contamination of superfund sites for appropriate cost sharing. The Department's estimate for realized recoveries was $1.0 million and $3.1 million at December 31, 2014, and 2013, respectively, primarily representing an interfund receivable from Seattle Public Utilities for recovery of remediation costs incurred related to the lower Duwamish Waterway site. The Department's estimate for not yet realized recoveries from other parties for their share of remediation work performed that partially offset the Department's estimated environmental liabilities were zero at December 31, 2014, and 2013. As of December 31, 2014, and 2013, environmental costs of $34.5 million and $31.7 million were deferred primarily for the cleanup estimate of the Department's responsibility for the Lower Duwamish Waterway Superfund Site, and these costs will be recovered through future rates in accordance with GASB Statement No. 62.

The changes in the provision for environmental liabilities at December 31, 2014, and 2013 are as follows:

($ in millions)	2014	2013
Beginning environmental liability, net of recoveries	$ 60.2	$ 58.3
Payments	(6.4)	(6.3)
Incurred environmental liability	3.8	8.2
Ending environmental liability, net of recoveries	$ 57.6	$ 60.2

The provision for environmental liabilities included in current and noncurrent liabilities at December 31, 2014 and 2013, is as follows:

($ in millions)	2014	2013
Noncurrent liabilities	$ 34.0	$ 46.2
Accounts payable and other current liabilities	23.6	14.0
Ending liability	$ 57.6	$ 60.2

12. OTHER LIABILITIES

Other liabilities include unearned capital fees which are amortized to revenues as earned, deposits that are returned to customers, and certain other unearned revenues which expire at contract completion.

Other liabilities at December 31, 2014 and 2013 consisted of the following:

($ in millions)	2014	2013
Other liabilities:		
Unearned capital fees	$ 20.7	$ 13.8
Customer deposits—sundry sales	5.4	4.4
Unearned operations and maintenance revenues	0.2	0.4
Unearned revenues—other	0.4	0.6
Total	$ 26.7	$ 19.2

13. DEFERRED INFLOWS OF RESOURCES

Seattle City Council passed resolutions authorizing the reporting of certain credits as regulatory liabilities in accordance with Statement No. 62 of the GASB, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB & AICPA Pronouncements*.

The unearned revenue for the Rate Stabilization Account for 2014 and 2013 is the result of spreading retail electric revenues and related activity over multiple periods to reduce the need for rapid and substantial rate increases (see Note 3 Rate Stabilization Account). Payments received from Bonneville's Energy Conservation Agreement are amortized to revenues over 20 years.

Bonneville Slice contract true-up credits are reported as regulatory liabilities in the year invoiced and recognized as revenue in the following year (see Note 15 Long-Term Purchased Power, Exchanges and Transmission). Seattle City Council affirmed the Department's practice of recognizing the effects of reporting the fair value of exchange contracts in future periods for rate making purposes and maintaining regulatory accounts to spread the accounting impact of these accounting adjustments, in Resolution No. 30942 adopted January 16, 2007 (see Note 15 Long-Term Purchased Power, Exchanges, and Transmission).

Deferred inflows of resources at December 31, 2014 and 2013 consisted of the following:

($ in millions)	2014	2013
Deferred inflows of resources:		
Unearned revenue—rate stabilization account	$ 89.4	$ 85.0
Bonneville energy conservation agreement	16.4	10.4
Bonneville Slice true-up credit	5.6	4.3
Exchange energy: regulatory gain	0.1	1.0
Total	$ 111.5	$ 100.7

14. SHORT-TERM ENERGY CONTRACTS AND DERIVATIVE INSTRUMENTS

The Department engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve the Department's load obligations and using these resources to capture available economic value. The Department makes frequent projections of electric loads at various points in time based on, among other things, estimates of factors such as customer usage and weather, as well as historical data and contract terms. The Department also makes recurring projections of resource availability at these points in time based on variables such as estimates of stream flows, availability of generating units, historic and forward market information, contract terms, and experience. On the basis of these projections, the Department purchases and sells wholesale electric capacity and energy to match expected resources to expected electric load requirements, and to realize earnings from surplus energy resources. These transactions can be up to 24 months forward. Under these forward contracts, the Department commits to purchase or sell a specified amount of energy at a specified time, or during a specified time in the future. Except for limited intraday and interday trading to take advantage of owned hydro storage, the Department does not take market positions in anticipation of generating revenue. Energy transactions in response to forecasted seasonal resource and demand variations require approval by the Department's Risk Oversight Council.

It is the Department's policy to apply the normal purchase and normal sales exception of Statement No. 53 of the GASB, *Accounting and Financial Reporting for Derivative Instruments*, as appropriate. Certain forward purchase and sale of electricity contracts meet the definition of a derivative instrument, but are intended to result in the purchase or sale of electricity delivered and used in the normal course of operations. Accordingly, the Department considers these forward contracts as normal purchases and normal sales under Statement No. 53. These transactions are not required to be recorded at fair value in the financial statements.

The aggregate contract amounts, fair value, and unrealized gain or (loss) of the Department's commodity derivative instruments qualifying as normal purchases and normal sales at December 31 follow:

($ in millions)	Aggregate Contract Amount	Aggregate Fair Value	Unrealized Gain (Loss)
2014			
Sales	$ 13.3	$ 11.9	$ 1.4
Purchases	-	-	-
Total	$ 13.3	$ 11.9	$ 1.4

	Aggregate Contract Amount	Aggregate Fair Value	Unrealized Gain (Loss)
2013			
Sales	$ 19.4	$ 22.4	$ (3.0)
Purchases	1.5	1.7	0.2
Total	$ 20.9	$ 24.1	$ (2.8)

Fair value measurements at December 31, 2014, and 2013, used an income valuation technique consisting of Kiodex Forward Curves and interest rates from HIS Global Insight that are used to calculate discount rates.

All derivative instruments not considered as normal purchases and normal sales are to be recorded within the financial statements using derivative accounting according to Statement No. 53. In 2010, the Seattle City Council adopted a resolution granting the Department authority to enter into certain physical put and call options that would not be considered normal purchases and normal sales under Statement No. 53. The Department did not have any such activity for 2014 and 2013. In addition, the Seattle City Council has deferred recognition of the effects of reporting the fair value of derivative financial instruments for rate-making purposes, and the Department maintains regulatory accounts to defer the accounting impact of these accounting adjustments in accordance with GASB Statement No. 62, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements* (see Notes 6 Other Assets and 13 Deferred Inflows of Resources).

Market Risk—Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Market risk may also be influenced by the number of active, creditworthy market participants, and to the extent that nonperformance by market participants of their contractual obligations and commitments affects the supply of, or demand for, the commodity. Because the Department is active in the wholesale energy market, it is subject to market risk.

Credit Risk—Credit risk relates to the potential losses that the Department would incur as a result of nonperformance by counterparties of their contractual obligations to deliver energy or make financial settlements. Changes in market prices may dramatically alter the size of credit risk with counterparties, even when conservative credit limits are established. The Department seeks to mitigate credit risk by: entering into bilateral contracts that specify credit terms and protections against default; applying credit limits and duration criteria to existing and prospective counterparties; and actively monitoring current credit exposures. The Department also seeks assurances of performance through collateral requirements in the form of letters of credit, parent company guarantees, or prepayment.

The Department has concentrations of suppliers and customers in the electric industry including: electric utilities; electric generators and transmission providers; financial institutions; and energy marketing and trading companies. In addition, the Department has concentrations of credit risk related to geographic location as it operates in the western United States. These concentrations of counterparties and concentrations of geographic location may impact the Department's overall exposure to credit risk, either positively or negatively, because the counterparties may be similarly affected by changes in conditions.

Other Operational and Event Risk—There are other operational and event risks that can affect the supply of the commodity, and the Department's operations. Due to the Department's primary reliance on hydroelectric generation, the weather, including spring time snow melt, runoff, and rainfall, can significantly affect the Department's operations. Other risks include regional planned and unplanned generation outages, transmission constraints or disruptions, environmental regulations that influence the availability of generation resources, and overall economic trends.

15. LONG-TERM PURCHASED POWER, EXCHANGES, AND TRANSMISSION

Bonneville Power Administration—The Department purchases electric energy from the U.S. Department of Energy, Bonneville Power Administration (Bonneville) under the Block and Slice Power Sales Agreement, a 17-year contract, for the period October 1, 2011 through September 30, 2028. Block quantities, Slice percentage and Bonneville rates are expected to be recalculated periodically during the term of the contract. Rates will be developed and finalized every two years. Accordingly, certain estimates and assumptions were used in the calculations in the estimated future payments table below.

The terms of the Slice product specify that the Department will receive a percentage of the actual output of the Federal Columbia River Power System (the System). The percentage is adjusted annually with a Slice Adjustment Ratio no greater than 1.0 times the 3.65663 initial slice percentage, no later than 15 days prior to the first day of each federal fiscal year, beginning with fiscal year 2012. The current Slice percentage is 3.62763%, the same as the previous fiscal year. The cost of Slice power is based on the Department's same percentage of the expected costs of the System and is subject to true-up adjustments based on actual costs with specified exceptions.

Bonneville's Residential Exchange Program (REP) was established as a mechanism to distribute financial benefits of the Federal Columbia River Power System to residential customers of the region's investor owned utilities (IOUs). In May 2007, the Ninth Circuit Court (the Court) rulings found the 2000 REP Settlement Agreements with IOUs inconsistent with the Northwest Power Act. To remedy this inconsistency, the court ruled that refunds be issued to non IOUs through 2019. The Department received $5.7 million in both 2014 and 2013 in billing credits related to both the Block and Slice agreements as a result of the Court decision.

Lucky Peak—In 1984, the Department entered into a purchase power agreement with four irrigation districts to acquire 100% of the net surplus output of a hydroelectric facility that began commercial operation in 1988 at the existing Army Corps of Engineers Lucky Peak Dam on the Boise River near Boise, Idaho. The irrigation districts are owners and license holders of the project, and the FERC license expires in 2030. The agreement, which expires in 2038, obligates the Department to pay all ownership and operating costs, including debt service, over the term of the contract, whether or not the plant is operating or operable.

The Department provided and billed Lucky Peak $0.3 million for operational and administrative services in both 2014 and 2013. These amounts are recorded as offsets to purchased power expense. The Department paid $3.2 million for energy from Lucky Peak in both 2014 and 2013.

The Department's receivables from Lucky Peak were less than $0.1 million at December 31, 2014, and 2013, respectively. The Department's payables to Lucky Peak were $0.3 million and $0.4 million at December 31, 2014, and 2013, respectively.

British Columbia—High Ross Agreement—In 1984, an agreement was reached between the Province of British Columbia and the City under which British Columbia will provide the Department with energy equivalent to that which would have resulted from an addition to the height of Ross Dam. Delivery of this energy began in 1986 and is to be received for 80 years. In addition to the direct costs of energy under the agreement, the Department incurred costs of approximately $8.0 million in prior years related to the proposed addition and was obligated to help fund the Skagit Environmental Endowment Commission through four annual $1.0 million payments. These other costs are included in utility plant-in-service as an intangible asset, and are being amortized to purchase power expense over 35 years through 2035 (see Note 2 Utility Plant).

Energy received and expenses incurred under these and other long-term purchased power agreements at December 31, 2014 and 2013 were as follows:

	Expense		Average Megawatts	
($ in millions)	2014	2013	2014	2013
Bonneville Block	$ 78.1	$ 70.1	266.5	270.0
Bonneville Slice	77.5	80.0	322.0	309.9
Long-term purchase power—Bonneville	155.6	150.1	588.5	579.9
Lucky Peak, including royalties	6.3	5.2	35.2	24.6
British Columbia - High Ross Agreement	13.4	13.4	35.1	35.7
Grant County Public Utility District	3.2	3.0	2.5	3.8
Grand Coulee Project Hydro Authority	6.0	5.5	31.1	29.1
Bonneville South Fork Tolt billing credit	(3.3)	(3.3)	-	-
Renewable energy - State Line Wind	23.7	23.8	40.8	41.4
Renewable energy - other	7.1	4.5	12.5	9.0
Exchanges and loss returns energy at fair value	8.9	9.2	14.5	16.6
Long-term purchased power booked out	(6.7)	(8.3)	(25.3)	(31.8)
Long-term purchased power—other	58.6	53.0	146.4	128.4
Total	$ 214.2	$ 203.1	734.9	708.3

Renewable Energy Purchase and/or Exchanges—The Energy Independence Act, Chapter 19.285 Revised Code of Washington, requires all qualifying utilities in Washington State to meet certain annual targets of eligible new renewable resources and/or equivalent renewable energy credits as a percentage of total energy delivered to retail customers. The annual targets are: at least 3% by 2012, at least 9% by 2016, and at least 15% by 2020. The Department's 2014 and 2013 resource portfolio met the 3% target.

Energy Exchange—Northern California Power Agency (NCPA) and the Department executed a long-term Capacity and Energy Exchange Agreement in March 1993. The Department delivers energy to NCPA from June through October 15. NCPA returns energy under conditions specified in the contract at a 1.2:1 ratio of exchange power, from November through April. The agreement includes financial settlement and termination options. In a letter NCPA dated May 17, 2011, NCPA gave seven year's advance written notice to the Department terminating the agreement effective no later than May 31, 2018.

Fair Value of Exchange Energy—Exchange energy receivable and the related regulatory gains at December 31, 2014 and 2013, were valued using Kiodex Forward Curves, and Dow Jones U.S. Daily Electricity Price Indices for settled deliveries. An income valuation technique that uses interest rate forecasts from HIS Global Insight is used to discount for present value based on the interest rate for U.S. Government Treasury constant maturities, bond-equivalent yields by the future month of the transactions (see Note 13 Deferred Inflows of Resources).

Estimated Future Payments Under Purchased Power, Transmission and Related Contracts—The Department's estimated payments for purchased power and transmission, Renewable Energy Credits (RECs) and other contracts for the period from 2015 through 2065, undiscounted, are as follows:

Years Ending December 31 *($ in millions)*	**Estimated Payments** [(a)]
2015	$ 286.6
2016	302.8
2017	307.3
2018	324.8
2019	336.5
2020-2024	1,766.1
2025-2029(b)(c)	1,204.1
Thereafter (through 2065)	239.0
Total	$ 4,767.2

(a) 2015 to 2019 includes estimated REP recoveries from Bonneville.
(b) Bonneville transmission contract expires July 31, 2025.
(c) Bonneville Block and Slice contract expires September 30, 2028.

16. COMMITMENTS AND CONTINGENCIES

Operating Leases—While the Department owns several buildings including those at the Skagit and Boundary hydroelectric projects, service centers, and the System Control Center, the Department leases some administrative office space from the City. Such lease payments to the City are made through a central cost allocation process, similar to all other payments for tenancy of City property. These payments are not included in the operating leases table below. The Department also leases certain office equipment and smaller facilities for various purposes through long-term operating lease agreements. Expenses for all operating leases totaled $1.6 million in 2014 and $1.3 million in 2013.

Minimum payments under the operating leases are:

Year Ending December 31 ($ in millions)	Minimum Payments
2015	$ 1.4
2016	1.4
2017	1.4
2018	1.0
2019	0.9
Total	$ 6.1

2015 Capital Program— The budget for the Department's 2015 program for capital improvement, conservation, and deferred operations and maintenance including required expenditures on assets owned by others is $561.1 million. At December 31, 2014, the Department had approximately $30.3 million in commitments relating thereto. Department overhead costs and other allocations associated with the capital program are not included in the budget amount.

Federal Energy Regulatory Commission Fees—Estimated Federal land use and administrative fees related to hydroelectric licenses total $258.9 million through 2055; these estimates are subject to change. The estimated portion of fees attributed to the Skagit and Tolt licenses are excluded after 2025, at which time their current FERC licenses expire. The estimated portion of Boundary fees is included through 2055, the year in which the current license issued by FERC expires. The current Boundary FERC license and related issues are discussed below.

New Boundary License—The Department's FERC license for the Boundary Project expired on September 30, 2011 and a new license was issued on March 20, 2013 with a 42 year life and a total cost of $48.6 million. The terms and conditions of the new license have been evaluated and the Department has moved to the license implementation process, which imposes mitigation of endangered species including water quality standards and conservation management.

As part of the application process, the Department negotiated a settlement with external parties such as owners of other hydroelectric projects, Indian tribes, conservation groups and other government agencies. The settlement sought to preserve the Department's operational flexibility at Boundary Dam while providing for natural resource protection, mitigation and enhancement measures.

The cost projections for such mitigation over the expected 42-year life of the license, included in the Department's license application, were estimated to be $399.1 million adjusted to 2014 dollars, of which $21.2 million were expended through 2014. Projected mitigation cost estimates are subject to revision as more information becomes available.

Skagit and South Fork Tolt Licensing Mitigation and Compliance—In 1995, the FERC issued a license for operation of the Skagit hydroelectric facilities through April 30, 2025. On July 20, 1989, the FERC license for operation of the South Fork Tolt hydroelectric facilities through July 19, 2029, became effective. As a condition for both of these licenses, the Department has taken and will continue to take required mitigating and compliance measures.

Total Skagit license mitigation costs from the effective date until expiration of the federal operating license were estimated at December 31, 2014, to be $127.8 million, of which $110.9 million had been expended. Total South Fork Tolt license mitigation costs were estimated at $1.8 million, of which $1.3 million were expended through 2014. In addition to the costs listed for South Fork Tolt mitigation, the license and associated settlement agreements required certain other actions related to wildlife studies and wetland mitigation for which no set dollar amount was listed. Requirements for these actions have been met, and no further expenditures need to be incurred for these items.

Capital improvement, other deferred costs, and operations and maintenance costs are included in the estimates related to the settlement agreements for both licenses. Amounts estimated are adjusted to 2014 dollars. Department labor and other overhead costs associated with the activities required by the settlement agreements for the licenses are not included in the estimates.

Hydroelectric projects must satisfy the requirements of the Endangered Species Act (ESA) and the Clean Water Act in order to obtain a FERC license. ESA and related issues are discussed below.

Endangered Species—Several fish species that inhabit waters where hydroelectric projects are owned by the Department, or where the Department purchases power, have been listed under the ESA as threatened or endangered. Although the species were listed after FERC licenses were issued for all of the Department's hydroelectric projects, the ESA listings still affect operations of the Department's Boundary, Skagit, Tolt, and Cedar Falls hydroelectric projects.

Federal Regulations in response to the listing of species affect flow in the entire Columbia River system. As a result of these regulations, the Department's power generation at its Boundary Project is reduced in the fall and winter when the region experiences its highest sustained energy demand. The Boundary Project's firm capability is also reduced.

The Department, with the support of City Council, elected to take a proactive approach to address issues identified within the ESA. The Department is carrying out an ESA Early Action program in cooperation with agencies, tribes, local governments, and watershed groups for bull trout, Chinook salmon, and steelhead in the South Fork Tolt and Skagit Watersheds. The ESA Early Action program is authorized by City Council, but is separate from any current FERC license requirements. The program includes habitat acquisition, management and restoration. The ESA Early Action has been successful in protecting listed species. Total costs for the Department's share of the Early Action program from inception in 1999 through December 31, 2014, are estimated to be $9.0 million, and $0.9 million has been allocated for the program in the 2015 budget.

Project Impact Payments—Effective August 2010, the Department renewed its contract with Pend Oreille County and committed to pay a total of $19.0 million over 10 years ending in 2019 to Pend Oreille County for impacts on county governments from the operations of the Department's hydroelectric projects. Effective February 2009, the Department renewed its contract with Whatcom County committing to pay a total of $15.8 million over 15 years ending in 2023. The payments compensate the counties, and certain school districts and towns located in these counties, for loss of revenues and additional financial burdens associated with the projects. The Boundary Project, located on the Pend Oreille River, affects Pend Oreille County, and Skagit River hydroelectric projects affect Whatcom County. The impact payments totaled $2.5 million and $2.4 million to Pend Oreille County, and $1.0 million and $1.0 million to Whatcom County in 2014 and 2013, respectively.

Energy Crisis Refund Litigation **—**The Department (City) is involved in various legal proceedings relating to the enormous price spikes in energy costs in California and the rest of the West Coast in 2000 and 2001.

- *California Refund Case, Appeals and Related Litigation*—In the proceeding before the Federal Energy Regulatory Commission (FERC), various public and private California entities (the California Parties) sought refunds in markets that had been created by the State of California. In February 2011, the City agreed to a settlement, which was eventually approved by the trial court and by FERC. Under the settlement, the City has resolved this matter for $9.0 million, none of which was immediately paid by the Department. As part of the settlement, the City has assigned its accounts receivable from the California Independent Systems Operator to the California Parties, which was valued at approximately $1.4 million at the time of the settlement agreement. The balance of over $7.6 million is contingent upon the Department recovering monies in the Pacific Northwest Refund Case, discussed below. To date, the Department has received $4.6 million in payments in the Pacific Northwest Refund Case, half of which has been paid to the California parties pursuant to the settlement.

- *Pacific Northwest Refund Case*—In a proceeding before FERC, various buyers of energy, including the City, sought refunds from various sellers on energy sales in the Pacific Northwest between December 1999 and June 2001. The case was tried at FERC between August and October of 2013. In March 2014, the FERC administrative law judge issued an Initial Decision denying all refunds. In May 2014, the City filed a brief objecting to the Initial Decision, and the parties are now awaiting a final decision from FERC. Prior to the FERC trial, the City settled refund claims with twelve entities, with a combined total settlement amount of $4.6 million.

Taylor, et al. v. City **–** Four plaintiffs allege that certain Department managers retaliated and discriminated against them on the basis of age, race, gender, and sexual orientation. The Department managers deny all allegations of discrimination, harassment, and retaliation. An adverse result in litigation could result in awards of back pay, compensatory damages, and attorneys' fees. Trial is currently scheduled for November 23, 2015, in King County Superior Court. The Department's ultimate liability is indeterminate.

State Farm, et al. v. City, Puget Sound Energy(PSE) and Inghams **-** This case stems from a gas explosion in September 2011 in the Pinehurst neighborhood in Seattle. Discovery thus far indicates the Ingham home exploded after an undiscovered gas leak caused a gas buildup in the crawl space of their home. The Inghams were inside their home at the time, and Mrs. Ingham suffered severe burns. After cross-claims and joinders of additional parties, this case involves the claims of six insurance companies seeking over $1.0 million in property damages involving eight different properties and the personal injury claims of the Inghams and their next-door neighbors. The plaintiffs' theory against the Department is that the gas leak was caused by arcing electricity from a fallen Department power line blocks away from the Inghams' home. Puget Sound Energy is a co-defendant and was sanctioned by the State UTC regarding this incident. The case is scheduled for trial to commence on May 5, 2015. The Department's ultimate liability is indeterminate.

Other Contingencies—In addition to those noted above, in the normal course of business, the Department has various other legal claims and contingent matters outstanding. The Department believes that any ultimate liability arising from these actions will not have a material adverse impact on the Department's financial position, operations, or cash flows.

* * * * * *

SCHEDULES OF FUNDING PROGRESS

SCERS. The schedule of funding progress for SCERS is presented below for the most recent actuarial valuation and the two preceding valuations for which the Department has available data (dollar amounts in millions):

Actuarial Valuation Date January 1	Actuarial Value of Assets (A)	Actuarial Accrued Liabilities (AAL)[(a)] (B)	Unfunded AAL (UAAL)[(b)] (B-A)	Funding Ratio (A/B)	Covered Payroll[(c)] (C)	UAAL (or Excess) as a Percentage of Covered Payroll ((B-A)/C)
2012	$ 1,954.3	$ 2,859.3	$ 905.0	68.3 %	$ 557.0	162.5 %
2013	1,920.1	3,025.3	1,105.2	63.5	567.8	194.6
2014	2,094.3	3,260.1	1,165.8	64.2	597.9	195.0

(a) Actuarial present value of benefits less actuarial present value of future normal costs based on entry age actuarial cost method.
(b) Actuarial accrued liabilities less actuarial value of assets; funding excess if negative.
(c) Covered payroll includes compensation paid to all active employees on which contributions were made in the year preceding the valuation date.

OPEB. The schedule of funding progress for the other post-employment benefit healthcare plans is presented below for the most recent actuarial valuation and the two preceding valuations for which the Department has available data (dollar amounts in millions):

Actuarial Valuation Date January 1	Actuarial Value of Assets (A)	Actuarial Accrued Liabilities (AAL) Entry Age (B)	Unfunded AAL (UAAL) (B-A)	Funding Ratio (A/B)	Covered Payroll (C)	UAAL as a Percentage of Covered Payroll ((B-A)/C)
2012	$ -	$ 74.7	$ 74.7	- %	$ 891.6	8.4 %
2013	-	78.9	78.9	-	942.0	8.4
2014	-	41.8	41.8	-	1,004.0	4.2

DEBT SERVICE COVERAGE

Following is a table that provides information for the Department's debt service coverage for years 2014, 2013, and 2012. The target level for debt service coverage was 1.8x on all bonds for 2014, 2013, and 2012 in accordance with current financial policies (which include a Rate Stabilization Account that will result in greater compliance of actual debt service coverage with the policy-specified level).

($ in millions)

Debt Service Coverage	**December 31**		
	2014	**2013**	**2012**
Revenues:			
Total operating revenues (a)	$ 890.5	$ 842.2	$ 800.3
Adjustments:			
Valuation of exchange power revenues	(25.3)	(18.8)	(12.6)
BPA conservation augmentation revenue	(0.7)	(0.5)	(0.2)
Investment income (b)	5.4	4.7	4.4
Proceeds/gain on sale of property	2.0	2.4	0.2
Principal receipts from suburban infrastructure receivables	0.8	0.7	0.5
Other income (expense), net, excluding CIAC (d)	0.1	3.1	2.6
Total revenues	$ 872.8	$ 833.8	$ 795.2
Expenses:			
Operation and maintenance	$ 548.3	$ 529.4	$ 492.3
Adjustments:			
Amortization and depreciation charged to operations	(24.8)	(22.3)	(21.5)
Valuation of exchange power purchases	(25.6)	(18.6)	(12.8)
Non-cash write-offs	(0.6)	(9.8)	(1.3)
Net non-cash claims	(1.3)	(1.0)	(1.5)
Subtotal	496.0	477.7	455.2
Taxes, excluding City Taxes (c)	35.4	36.5	33.9
Total expenses	$ 531.4	$ 514.2	$ 489.1
Revenue available for debt service	$ 341.4	$ 319.6	$ 306.1
Total Debt Service (d)	$ 184.8	$ 172.8	$ 169.1
Debt service coverage ratio	1.85	1.85	1.81

(a) Operating revenues adjusted by $4.1 million for prior years one-time true-up downward adjustment to unbilled revenue, a noncash item recorded in 2014. Prior years presented were not revised.
(b) Excludes GASB 31 adjustments for fair market value investments.
(c) City taxes take a junior lien to debt service.
(d) Debt service reported net of federal bond subsidies; revenue for federal debt subsidies also excluded from Other income (expense), net, excluding CIAC.

DEBT SERVICE COVERAGE: ALL BONDS

Year Ending December 31 ($ in millions)	Revenue Available for Debt Service	Debt Service Requirements	Debt Service Coverage
2014	$ 341.4	$ 184.8	1.85
2013	319.6	172.8	1.85
2012	306.1	169.1	1.81
2011	269.9	146.7	1.84
2010	210.4	118.4	1.78

INTEREST REQUIREMENTS AND PRINCIPAL REDEMPTION ON LONG-TERM DEBT

Year Ending December 31 ($ in millions)	Principal	Interest	Total[a]
2015	$ 104.9	$ 89.5	$ 194.4
2016	101.6	86.4	188.0
2017	102.8	81.3	184.1
2018	103.4	76.4	179.8
2019	100.2	71.4	171.6
2020	99.8	66.3	166.1
2021	99.5	61.4	160.9
2022	98.7	56.4	155.1
2023	100.1	51.3	151.4
2024	102.8	46.2	149.0
2025	91.3	41.0	132.3
2026	87.4	36.5	123.9
2027	61.3	32.6	93.9
2028	62.4	29.5	91.9
2029	55.7	26.5	82.2
2030	38.6	24.1	62.7
2031	40.1	22.2	62.3
2032	41.7	20.2	61.9
2033	43.2	18.2	61.4
2034	45.1	16.1	61.2
2035	47.0	13.9	60.9
2036	49.0	11.7	60.7
2037	36.1	9.6	45.7
2038	37.5	8.0	45.5
2039	39.0	6.2	45.2
2040	40.5	4.4	44.9
2041	28.1	2.9	31.0
2042	18.2	1.9	20.1
2043	19.0	1.2	20.2
2044	8.8	0.4	9.2
Total	$ 1,903.8	$ 1,013.7	$ 2,917.5

(a) Maximum debt service of $194.4 is due in 2015. See Note 7 Long-term debt.

OTHER INFORMATION (UNAUDITED)

STATEMENT OF LONG-TERM DEBT

As of December 31, 2014
($ in millions)

Bond Series	When Due	Interest Rate (%)	Amount Issued	Amount Outstanding	Amount Due Within One Year	Accrued Interest
Series 2008	2015	5.250	$ 16.3	$ 16.3	$ 16.3	$ 0.2
Series 2008	2016-2018	5.000	36.7	36.7		0.5
Series 2008	2019-2020	5.250	20.6	20.6		0.3
Series 2008	2021-2022	5.500	21.4	21.4		0.3
Series 2008	2023	5.750	10.8	10.8		0.2
Series 2008	2024-2025	6.000	23.6	23.6		0.4
Series 2008	2026-2029	5.750	56.4	56.4		0.8
Series 2010A	2015-2021	4.447	4.6	4.6		0.1
Series 2010A	2022	4.597	7.2	7.2		0.1
Series 2010A	2023	4.747	7.5	7.5		0.1
Series 2010A	2024	4.947	7.7	7.7		0.2
Series 2010A	2025	5.047	8.0	8.0		0.2
Series 2010A	2026	5.147	8.2	8.2		0.2
Series 2010A	2027	5.247	8.5	8.5		0.2
Series 2010A	2028-2030	5.470	27.4	27.4		0.6
Series 2010A	2031-2040	5.570	102.6	102.5		2.4
Series 2010B	2015	3.000	1.4	1.4	1.4	0.0
Series 2010B	2015	5.000	43.8	43.8	43.8	0.9
Series 2010B	2016	4.000	10.0	10.0		0.2
Series 2010B	2016	5.000	38.3	38.3		0.8
Series 2010B	2017	4.000	4.4	4.4		0.1
Series 2010B	2017	5.000	46.3	46.3		1.0
Series 2010B	2018	4.000	5.0	5.0		0.1
Series 2010B	2018	5.000	38.8	38.8		0.8
Series 2010B	2019	4.000	1.5	1.5		0.0
Series 2010B	2019	5.000	42.7	42.7		0.9
Series 2010B	2020	4.000	2.6	2.6		0.0
Series 2010B	2020	5.000	43.9	43.9		0.9
Series 2010B	2021-2026	5.000	187.8	187.8		3.9
Series 2010C	2015-2040	5.590	13.3	13.3		0.3
Series 2011A	2015-2027	5.000	176.9	160.4	13.0	3.5
Series 2011A	2028	5.250	9.4	9.4		0.2
Series 2011A	2029-2030	5.500	20.4	20.4		0.5
Series 2011A	2031-2036	5.250	75.8	75.8		1.6
Series 2011B	2027	5.750	10.0	10.0		0.2
Series 2012A	2015-2027	5.000	198.0	198.0	12.2	0.8
Series 2012A	2028	3.250	12.4	12.4		0.0
Series 2012A	2034-2036	4.000	25.1	25.1		0.1
Series 2012A	2037-2041	4.000	49.1	49.1		0.2
Series 2012C	2028	3.400	4.3	4.3		0.0
Series 2012C	2029	3.500	7.7	7.7		0.0
Series 2012C	2030	3.500	7.7	7.7		0.0
Series 2012C	2031-2033	3.750	23.4	23.4		0.1
Series 2013	2015	4.000	2.9	2.9	2.9	0.1
Series 2013	2016-2033	5.000	97.4	97.4		2.3
Series 2013	2034-2035	4.000	14.7	14.7		0.3
Series 2013	2036-2038	4.125	24.4	24.4		0.5
Series 2013	2039-2043	4.500	48.3	48.3		1.0
Series 2014	2015-2029	5.000	163.2	163.2	15.3	1.3
Series 2014	2030-2038	4.000	53.9	53.9		0.3
Series 2014	2039-2040	4.000	14.8	14.8		0.1
Series 2014	2041-2044	4.000	33.3	33.3		0.2
Total			$ 1,920.4	$ 1,903.8	$ 104.9	$ 30.0

OTHER INFORMATION (UNAUDITED)

POWER COSTS AND STATISTICS

Year ending December 31 *($ in millions)*	2014	2013	2012	2011	2010
POWER COSTS					
Hydroelectric generation(a)(c)	$ 49.9	$ 54.0	$ 45.7	$ 43.3	$ 35.6
Long-term purchased power(b)	214.3	203.1	204.1	206.9	223.6
Wholesale power purchases(c)(e)	14.9	19.8	11.8	11.5	24.5
Fair valuation & other power purchases(b)(e)	17.7	14.1	7.8	9.0	25.1
Owned transmission(a)	15.3	15.1	14.5	12.4	11.0
Wheeling expenses	42.1	37.4	36.5	38.9	38.5
Other power expenses	13.2	12.2	10.3	10.2	10.2
Total power costs	367.4	355.7	330.7	332.2	368.5
Less short-term wholesale power sales(c)	(96.8)	(63.0)	(70.4)	(102.7)	(74.5)
Less other power-related revenues	(25.5)	(21.5)	(16.8)	(37.7)	(33.5)
Less fair valuation other power-related(b)	(25.3)	(18.9)	(12.5)	(17.0)	(33.0)
Net power costs	$ 219.8	$ 252.2	$ 231.0	$ 174.8	$ 227.5
POWER STATISTICS (MWh)					
Hydroelectric generation(c)	7,091,368	6,108,908	6,947,088	7,546,905	5,509,191
Long-term purchased power(b)	6,658,689	6,482,960	7,232,362	7,859,766	6,843,267
Wholesale power purchases(c)	900,527	2,072,066	2,592,354	1,696,861	1,550,224
Wholesale power sales(c)	(4,083,391)	(3,854,352)	(5,625,088)	(6,053,258)	(3,334,872)
Other(d)	(722,984)	(805,810)	(1,130,247)	(928,663)	(702,434)
Total power available	9,844,209	10,003,772	10,016,469	10,121,611	9,865,376
Less self consumed energy	(29,717)	(30,910)	(31,072)	(32,752)	(30,726)
Less system losses	(473,908)	(466,462)	(518,755)	(488,627)	(463,654)
Total power delivered to retail customers	9,340,584	9,506,400	9,466,642	9,600,232	9,370,996
Net power cost per MWh delivered	$ 23.53	$ 26.53	$ 24.40	$ 18.21	$ 24.27

(a) Including depreciation.

(b) Long-term purchased power, fair valuation power purchases and fair valuation other power-related include energy exchanged under seasonal and other exchange contracts valued at market in accordance with GASB Statement No. 62, Codification of Accounting *and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB & AICPA Pronouncements.*

(c) The level of generation (and consequently the amount of power purchased and sold on the wholesale market) can fluctuate widely from year to year depending upon water conditions in the Northwest region.

(d) "Other" includes seasonal exchange power delivered and miscellaneous power transactions.

(e) Bookout purchases are excluded from wholesale power purchases and are reported on a net basis in wholesale power sales.

Note: Certain dollar amounts for 2010 - 2013 have been revised to conform to the 2014 presentation.

HISTORICAL ENERGY RESOURCES (in MWh)

	2014	2013	2012	2011	2010
Department-Owned Generation					
Boundary Project	4,249,957	3,465,890	3,802,251	4,499,134	3,161,351
Skagit Hydroelectric Project					
Gorge	1,057,865	955,265	1,081,349	1,094,529	871,686
Diablo	857,757	828,200	937,646	920,969	720,244
Ross	796,513	726,560	939,943	870,310	647,899
Cedar Falls/Newhalem	65,687	77,397	122,615	111,959	69,948
South Fork Tolt	63,589	55,596	63,284	50,004	54,010
Subtotal	7,091,368	6,108,908	6,947,088	7,546,905	5,525,138
Energy Purchases					
Bonneville	5,155,271	5,079,991	5,633,906	6,214,839	5,242,301
Priest Rapids(a)	21,961	33,205	36,381	32,285	168,251
GCPHA(b)	272,842	254,568	255,569	237,785	240,787
High Ross	307,873	312,350	308,365	313,817	307,390
Lucky Peak	308,334	215,587	401,400	388,786	285,757
Stateline Wind Project	357,325	363,099	365,192	413,697	348,524
Columbia Ridge	68,920	51,577	49,779	50,120	50,955
Seasonal and Other Exchange(c)	411,555	69,940	100,782	276,656	278,885
Wholesale Market Purchases(d)	900,527	2,072,066	2,592,354	1,696,861	1,550,224
Subtotal	7,804,608	8,452,383	9,743,728	9,624,846	8,473,074
Total Department Resources	14,895,976	14,561,291	16,690,816	17,171,751	13,998,212
Minus Offsetting Energy Sales					
Firm Energy Sales and Marketing Losses(e)	461,259	466,303	557,279	520,394	421,627
Seasonal and Other Exchange(c)	507,117	236,864	491,980	476,488	376,337
Wholesale Market Sales(f)	4,083,391	3,854,352	5,625,088	6,053,258	3,334,872
Total Net Energy Resources	9,844,209	10,003,773	10,016,469	10,121,611	9,865,376

(a) City Light made an election for 2010 to purchase the energy instead of reselling at auction.
(b) Grand Coulee Project Hydroelectric Authority.
(c) Includes exchange contracts with the Northern California Power Authority (NCPA), Sacramento Municipal Utility District (SMUD) and the Lucky Peak Project.
(d) Purchases to compensate for low water conditions and to balance loads and resources.
(e) Energy provided to Public Utility District of Pend Oreille County under the Boundary Project's FERC license and include incremental losses due to expanded activity in the wholesale market.
(f) Runoff was 121% of historical average in 2012, and 133% of historical average in 2011.

CUSTOMER STATISTICS

Year ended December 31		2014		2013		2012		2011		2010
Average number of customers:										
Residential		374,619		367,837		362,658		360,442		359,079
Non-residential		40,437		40,218		39,950		39,909		39,779
Total		415,056		408,055		402,608		400,351		398,858
Megawatt-hours[b]:										
Residential	32%	2,987,711	33%	3,158,629	33%	3,098,745	34%	3,217,101	33%	3,073,405
Non-residential	68%	6,352,873	67%	6,347,771	67%	6,367,897	66%	6,383,131	67%	6,297,591
Total	100%	9,340,584	100%	9,506,400	100%	9,466,642	100%	9,600,232	100%	9,370,996
Average annual revenue per customer [b]:										
Residential	$	695	$	710	$	664	$	679	$	635
Non-residential	$	11,448	$	10,820	$	10,603	$	10,306	$	9,962

Year ended December 31	2014	2013	2012	2011	2010
Average annual consumption per customer (kWhs)[a][b]:					
Residential					
- Seattle	7,975	8,587	8,545	8,925	8,559
- National	n/a	10,908	10,837	11,279	11,500
Non-residential					
- Seattle	157,107	157,834	159,399	159,942	158,314
- National	n/a	125,778	125,674	126,703	125,325
Average rate per kilowatt-hour (cents)[a][b]					
Residential					
- Seattle	8.71	8.27	7.77	7.61	7.42
- National	n/a	12.12	11.88	11.72	11.54
Non-residential					
- Seattle	7.29	6.86	6.65	6.44	6.29
- National	n/a	8.84	8.64	8.78	8.75

(a) Source of national data: Department of Energy (www.eia.doe.gov/electricity/annual/) 2014 National average annual consumption data and average rate data not available . 2013 National average annual consumption and average rate data updated.
(b) Seattle amounts include an allocation for the net change in unbilled revenue. Effective 2013, allocation of net change in unbilled revenue excludes retail customer voluntary payments for conservation and solar energy. Prior years presented were not revised.

NOTE: Effective January 1, 2014, there was a comprehensive rate change of 5.6%. In addition, the most recent comprehensive rate change was 4.2% effective January 1, 2015. Notice of public hearings on future rate actions may be obtained on request to The Office of the City Clerk, 600-4th Ave, Floor Three, Seattle, WA 98104. Additional information about Council meetings can be found on the Web at www.seattle.gov/council/calendar.

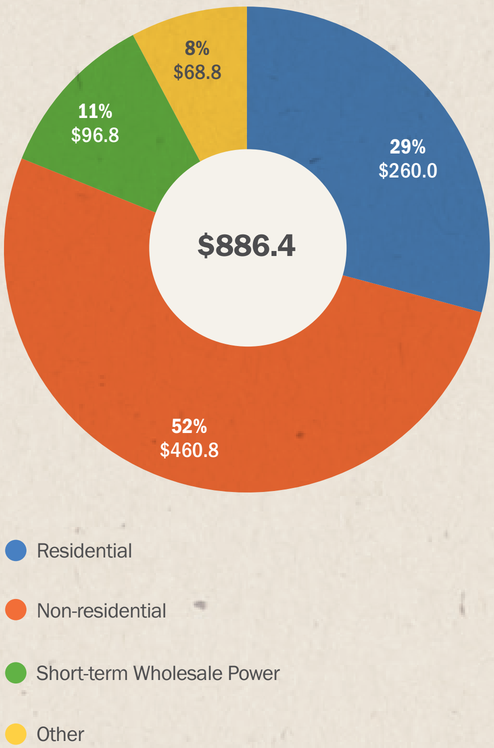
HIGHLIGHTS *(Unaudited)*

Financial *(in millions)*		**2014**		**2013**	**% Change**
Total operating revenues	$	886.4	$	842.2	5.00
Total operating expenses		734.1		711.0	3.10
Operating income		152.3		131.2	13.90
Investment income		7.9		0.8	89.90
Interest expense, net		77.9		79.3	(1.80)
Capital contributions and grants		28.4		49.7	(75.0)
Noncapital grants		3.8		3.2	16.4
Other income, net		6.8		7.1	(4.40)
Change in net position	$	121.3	$	112.7	7.10
Debt service coverage ratio, all bonds		1.85x		1.85x	-

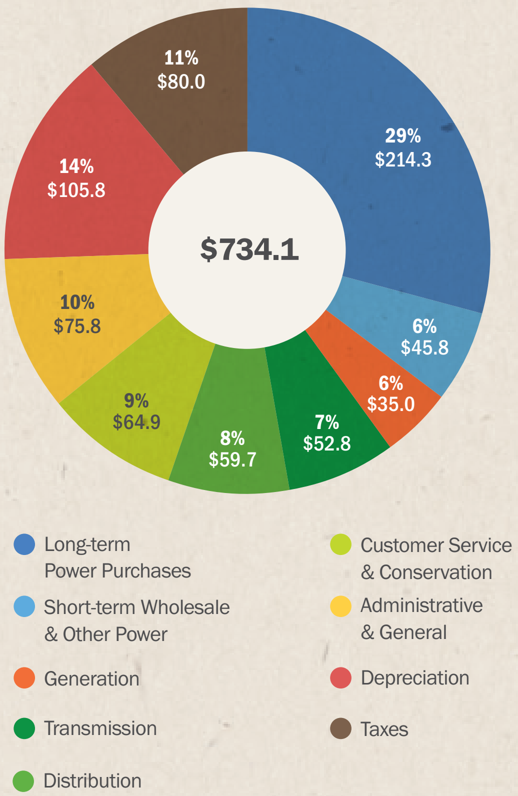
Energy	**2014**	**2013**	**% Change**
Total generation *(City Light-owned generation)*	7,091,368 MWh	6,108,908 MWh	13.9
System load	9,911,624 MWh	10,048,700 MWh	(1.4)
Peak load (highest single hourly use)	1,867 MW (February 6, 2014)	1,841 MW (December 9, 2013)	1.4
Average number of residential and non-residential customers	415,056	408,055	1.7
Average annual residential and non-residential energy consumption (includes estimated unbilled revenue allocation)	165,640 kWh	166,421 kWh	(0.5)

MWh = Megawatt–hour(s) MW = Megawatt(s) kWh = Kilowatt–hour(s)

2014 OPERATING REVENUES
(in millions)



2014 OPERATING EXPENSES
(in millions)



FINANCIAL SUMMARY *(Unaudited)*

(in millions)

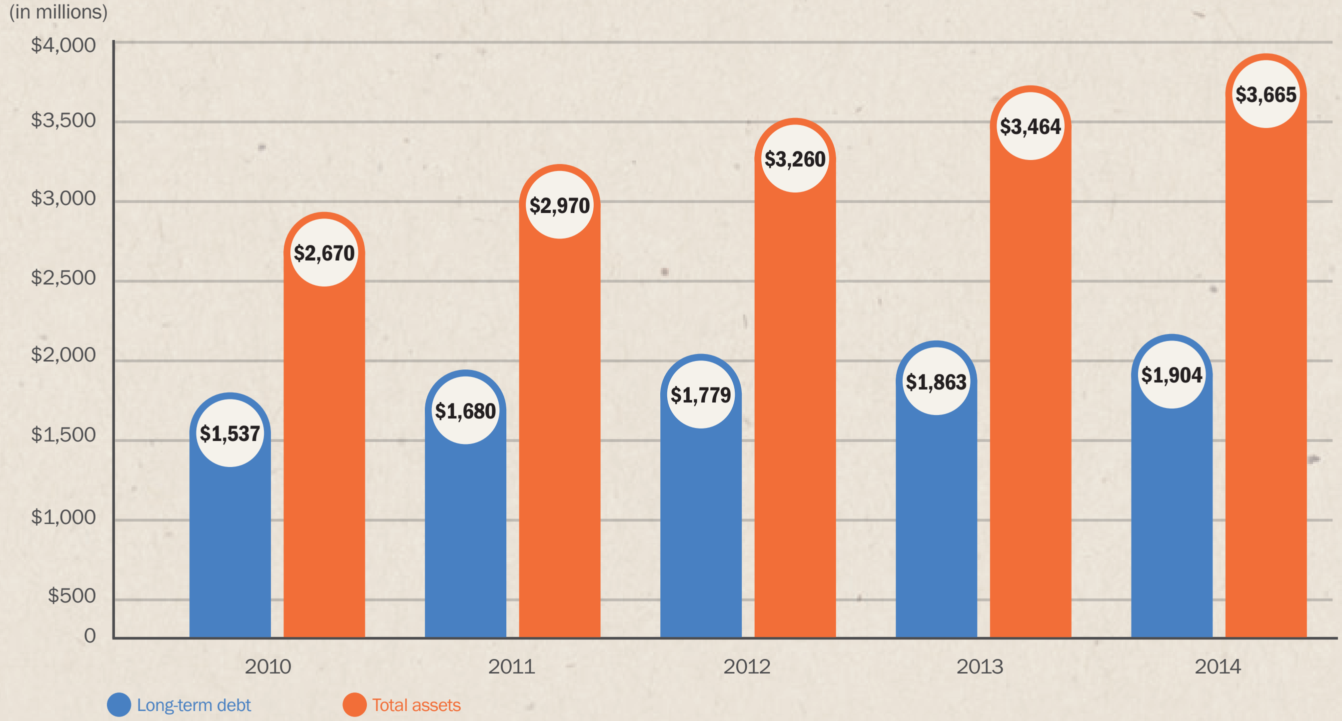
Years ended December 31,	2014	2013	2012	2011	2010
BALANCE SHEETS [A, B]					
Assets and Deferred Outflows of Resources					
Utility plant, net	$ 2,728.3	$ 2,541.1	$ 2,352.2	$ 2,200.3	$ 2,073.1
Restricted assets	298.4	227.0	275.7	209.2	140.2
Current assets	298.8	369.1	323.5	326.8	235.0
Other assets	319.7	301.0	278.9	243.2	221.5
Deferred outflows of resources	19.3	26.0	30.0	-	-
Total assets and deferred outflows of resources	$ 3,664.5	$ 3,464.2	$ 3,260.3	$ 2,979.5	$ 2,669.8
Liabilities, Deferred Inflows of Resources, & Net Position					
Long-term debt, net	$ 1,925.2	$ 1,870.3	$ 1,791.5	$ 1,640.6	$ 1,515.9
Noncurrent liabilities	67.3	78.1	74.8	55.8	55.0
Current liabilities	258.3	241.7	224.6	205.7	166.5
Other liabilities	26.7	19.2	15.4	130.6	77.8
Deferred inflows of resources	111.5	100.7	112.5	-	-
Net position	1,275.5	1,154.2	1,041.5	946.8	854.6
Total liabilities deferred inflows of resources, & net position	$ 3,664.5	$ 3,464.2	$ 3,260.3	$ 2,979.5	$ 2,669.8
STATEMENTS OF REVENUES AND EXPENSES [A, B]					
Operating Revenues					
Residential	$ 268.0	$ 256.6	$ 243.1	$ 242.1	$ 223.1
Non-residential	467.0	433.3	422.1	411.3	392.1
Unbilled revenue - net change	(14.2)	7.8	(0.9)	2.6	9.2
Total retail power revenues	720.8	697.7	664.3	656.0	624.4
Short-term wholesale power revenues	96.8	63.0	70.4	102.7	74.5
Other power-related revenues	50.8	40.4	29.3	54.7	66.6
Transfers from/(to) rate stabilization account[C]	(4.4)	18.3	13.2	(62.2)	(54.3)
Other revenues	22.4	22.8	23.1	21.0	22.0
Total operating revenues	886.4	842.2	800.3	772.2	733.2
Operating Expenses					
Long-term purchased power	214.3	203.1	204.1	206.9	223.6
Short-term wholesale power purchases	14.9	19.8	11.8	11.4	24.5
Other power expenses	30.9	26.4	18.1	19.2	35.3
Generation	35.0	40.0	32.3	29.3	22.5
Transmission	52.8	48.2	47.0	47.9	46.1
Distribution	59.7	59.5	60.8	58.3	56.4
Customer service	37.6	39.2	31.3	43.1	36.1
Conservation	27.3	21.5	20.8	19.1	16.8
Administrative and general	75.8	71.7	66.1	57.7	53.8
Taxes	80.0	79.3	74.9	73.6	70.4
Depreciation and amortization	105.8	102.3	94.8	88.8	86.4
Total operating expenses	734.1	711.0	662.0	655.3	671.9
Operating income	152.3	131.2	138.3	116.8	61.3
Noncapital grants	3.8	3.2	2.8	1.4	3.0
Other income (expense), net	6.8	7.1	4.7	4.2	2.2
Investment income	7.9	0.8	5.2	4.9	2.7
Total operating and other income	170.8	142.3	151.0	127.3	69.2
Interest Expense					
Interest expense	89.6	89.0	85.1	84.2	74.5
Amortization of debt expense	(5.9)	(5.9)	(2.8)	(3.9)	(4.2)
Interest charged to construction	(5.8)	(3.8)	(3.5)	(4.3)	(5.1)
Net interest expense	77.9	79.3	78.8	76.0	65.2
Capital Contributions and Grants	28.4	49.7	31.8	40.9	26.4
Change in net position	$ 121.3	$ 112.7	$ 104.0	$ 92.2	$ 30.4

[A] Effective January 1, 2014, the Department adopted Statement No. 65 of the GASB, Items Previously Reported as Assets and Liabilities. Accordingly, certain items previously reported as assets and liabilities are reclassified as deferred outflows of resources or deferred inflows of resources, and recognize as expense certain items previously reported as assets. See Note 1 Operations and Summary of Significant Accounting Policies paragraph.

[B] Effective January 1, 2013, the Department adopted Statement No. 62 of the GASB, Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB & AICPA Pronouncements. No changes to the accounting in areas affected by Statement No. 62 were necessary.

LONG-TERM DEBT *(Unaudited)*

LONG-TERM DEBT & TOTAL ASSETS

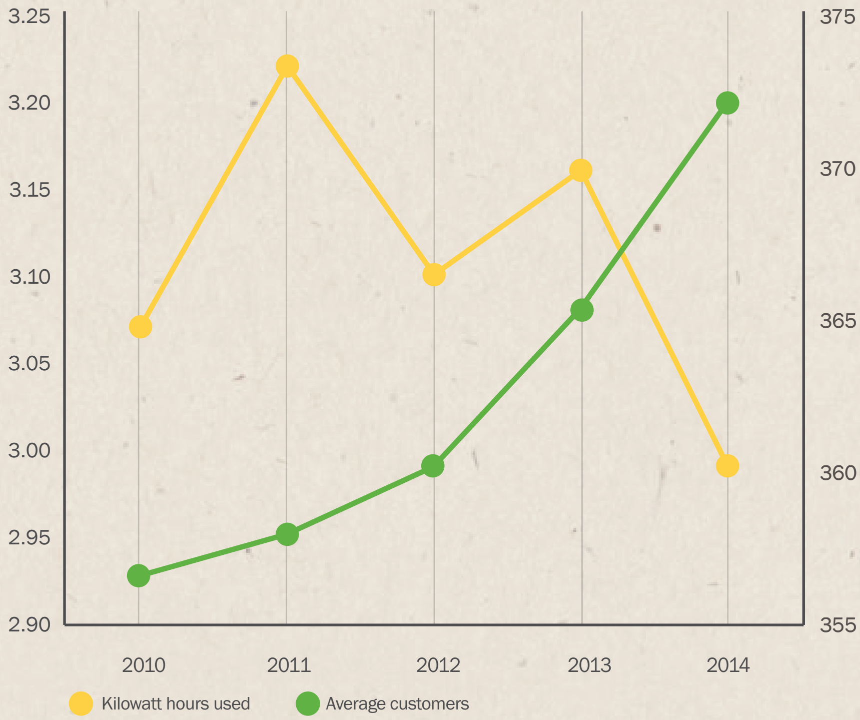


DEBT SERVICE COVERAGE 2010-2014

CUSTOMER STATISTICS *(Unaudited)*

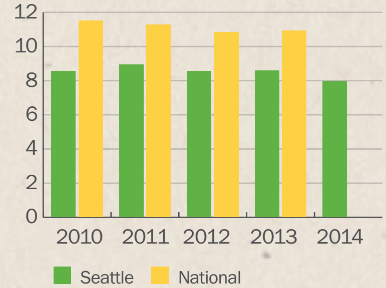
RESIDENTIAL CONSUMPTION

Kilowatt hours used (in billions) Number of customers (in thousands)



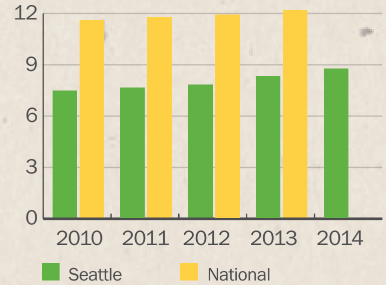
AVERAGE ANNUAL RESIDENTIAL CONSUMPTION*

(in thousands of kilowatt hours)



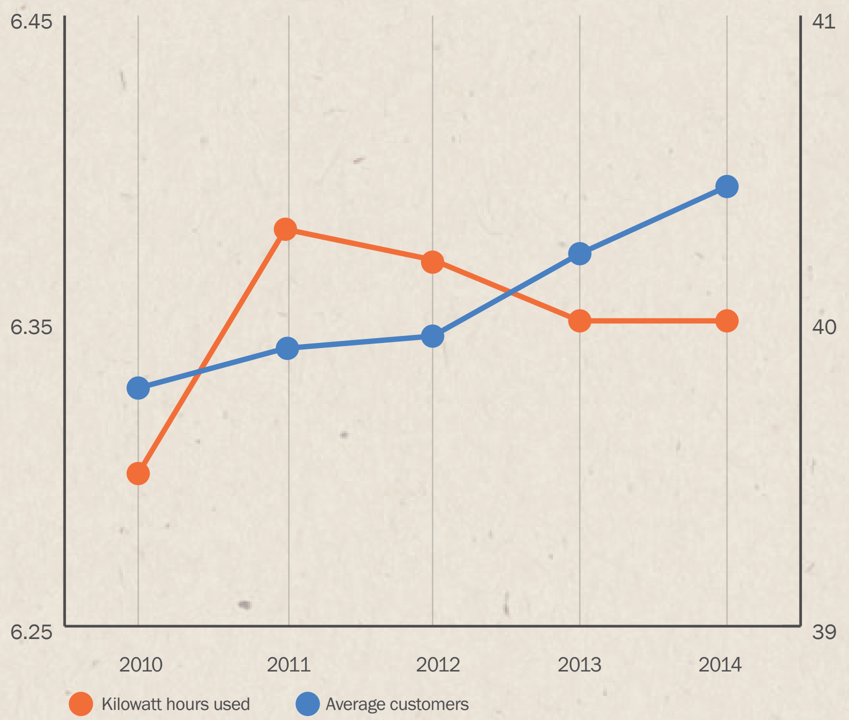
AVERAGE RESIDENTIAL RATES*

(in cents per kilowatt hour)



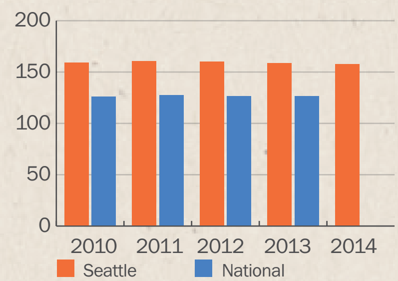
NON-RESIDENTIAL CONSUMPTION

Kilowatt hours used (in billions) Number of customers (in thousands)



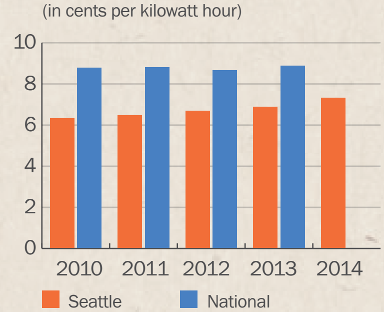
AVERAGE ANNUAL NON-RESIDENTIAL CONSUMPTION*

(in thousands of kilowatt hours)



AVERAGE NON-RESIDENTIAL RATES*

(in cents per kilowatt hour)



* Source of national data: Department of Energy (www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html; www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html). (2014 national average annual consumption data and average rate data not available; 2013 national average annual consumption and national average rate data updated.) Effective 2013, average annual consumption and average rates exclude unbilled revenue allocation of retail customer voluntary payments for conservation and solar energy. Prior years presented were not revised.

POWER *(Unaudited)*

2014 SOURCES OF POWER

(in percent megawatt hours)

GENERATED

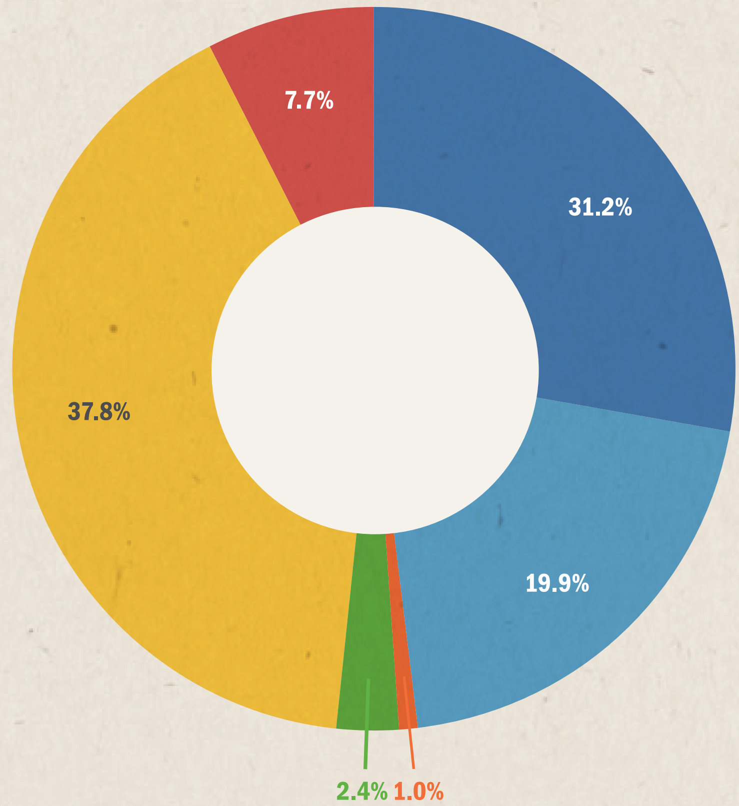
- Boundary
- Skagit
- Cedar Falls & South Fork Tolt

TREATY

- BC Hydro

PURCHASED

- BPA
- Other



2014 USES OF POWER

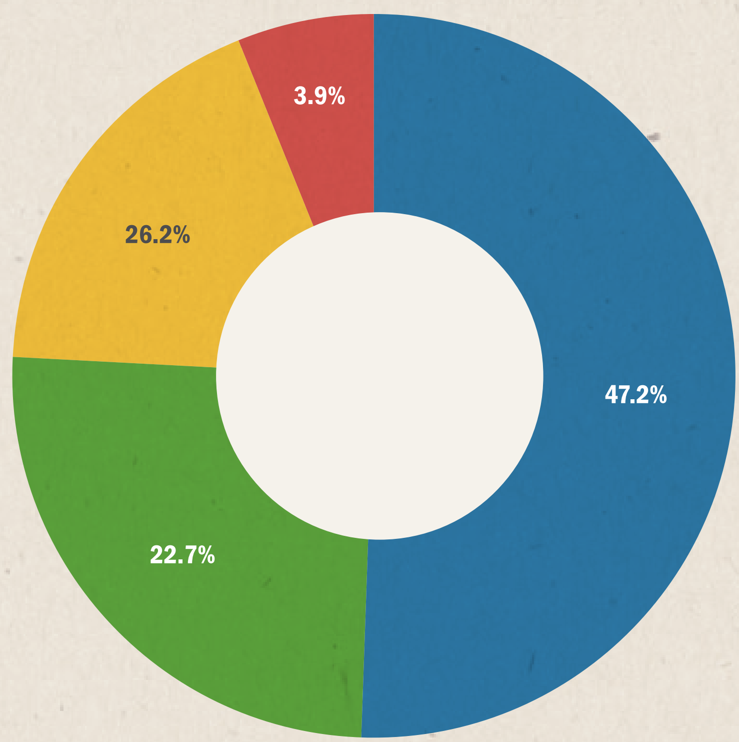
(in percent megawatt hours)

SERVICES

- Non-residential
- Residential

OTHER

- Wholesale & Other
- Seattle City Light Operations and Losses



SYSTEM CAPABILITY & REQUIREMENTS *(Unaudited)*

CHANGES IN OWNED TOTAL GENERATING INSTALLED CAPABILITY *(Unaudited)*

Year	Plant	Kilowatts Added [A]	Capability [B] Total Kilowatts
1904-09	Cedar Falls Hydro Units 1, 2, 3 & 4	10,400	10,400
1912	Lake Union Hydro Unit 10	1,500	11,900
1914-21	Lake Union Steam Units 11, 12 & 13	40,000	51,900
1921	Newhalem Hydro Unit 20	2,000	53,900
1921	Cedar Falls Hydro Unit 5	15,000	68,900
1924-29	Gorge Hydro Units 21, 22 & 23	60,000	128,900
1929	Cedar Falls Hydro Unit 6	15,000	143,900
1932	Cedar Falls Hydro Units 1, 2, 3 & 4	(10,400) [C]	133,500
1932	Lake Union Hydro Unit 10	(1,500) [C]	132,000
1936-37	Diablo Hydro Units 31, 32, 35 & 36	155,400	287,400
1951	Georgetown Steam Units 1, 2 & 3	21,000	308,400
1951	Gorge Hydro Unit 24	64,900	373,300
1952-56	Ross Hydro Units 41, 42, 43 & 44	450,000	823,300
1958	Diablo Plant Modernization	35,000	858,300
1961	Gorge Hydro, High Dam	46,000	904,300
1967	Georgetown Plant, performance test gain	2,000	906,300
1967	Boundary Hydro Units 51, 52, 53 & 54	639,400	1,545,700
1972	Centralia Units 1 & 2	102,400	1,648,100
1980	Georgetown Steam Units 1, 2, & 3	(23,000) [C]	1,625,100
1986	Boundary Hydro Units 55 & 56	400,000	2,025,100
1987	Lake Union Steam Units 11, 12 & 13	(40,000) [C]	1,985,100
1989-92	Gorge Units 21, 22, & 23, new runners	4,600	1,989,700
1990	Gorge Unit 24	32,000	2,021,700
1993	Centralia Transmission Upgrade	5,000	2,026,700
1995	South Fork Tolt Unit 81	16,800	2,043,500
2000	Centralia Units 1 & 2	(107,400) [D]	1,936,100
2013-2014	Boundary Hydro Units 53 & 55 rewind	39,000	1,975,100

[A] Certain historical capabilities were revised due to validation and testing.
[B] Capability is the maximum capability of generators and associated prime movers expressed in kilowatts (kW).
[C] Retirement of units (decrease in total capability).
[D] The Department's ownership interest of the Centralia Steam Plant was sold in May 2000.

SYSTEM REQUIREMENTS

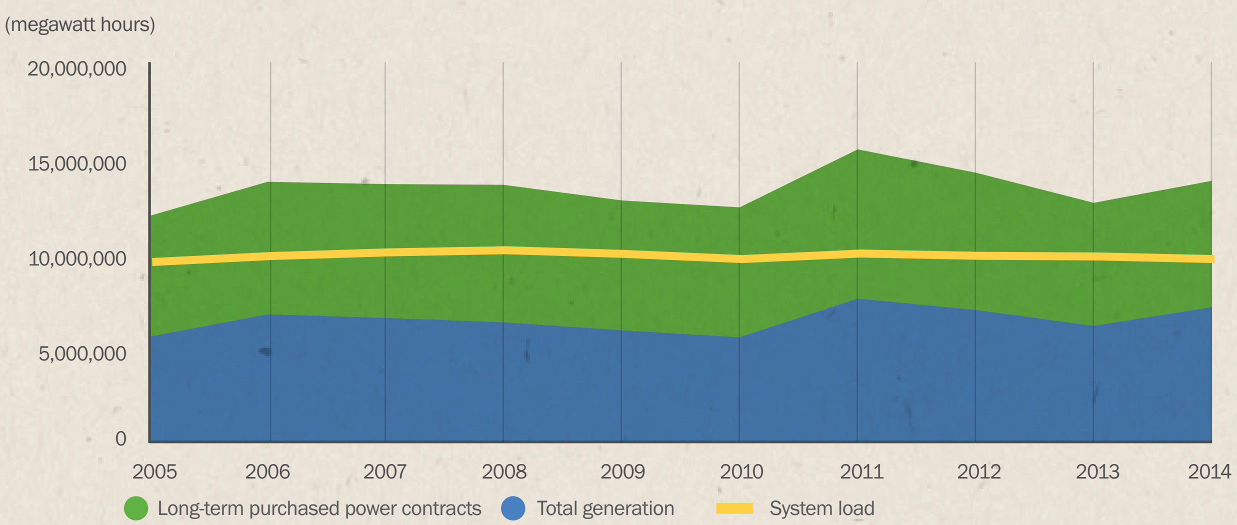
(Unaudited)

(in Kilowatts)

Year	Average Load	Peak Load [E]
1950	154,030	312,000
1955	381,517	733,000
1960	512,787	889,000
1965	635,275	1,138,000
1970	806,813	1,383,000
1975	848,805	1,429,387
1980	963,686	1,771,550
1985	1,025,898	1,806,341
1990	1,088,077	2,059,566
1995	1,072,692	1,748,657
2000	1,142,383	1,769,440
2005	1,113,513	1,719,020
2006	1,149,380	1,825,819
2007	1,171,596	1,777,096
2008	1,181,325	1,904,735
2009	1,162,375	1,859,875
2010	1,131,365	1,846,708
2011	1,164,725	1,748,833
2012	1,147,771	1,804,708
2013	1,147,112	1,840,792
2014	1,131,464	1,866,792

[E] Peak Load (highest single hourly use).

TOTAL GENERATION AND LONG-TERM PURCHASED POWER CONTRACTS VS. SYSTEM LOAD *(Unaudited)*



TAXES & CONTRIBUTIONS *(Unaudited)*

TAXES AND CONTRIBUTIONS BY SEATTLE CITY LIGHT TO THE COST OF GOVERNMENT *(Unaudited)*

(in millions)

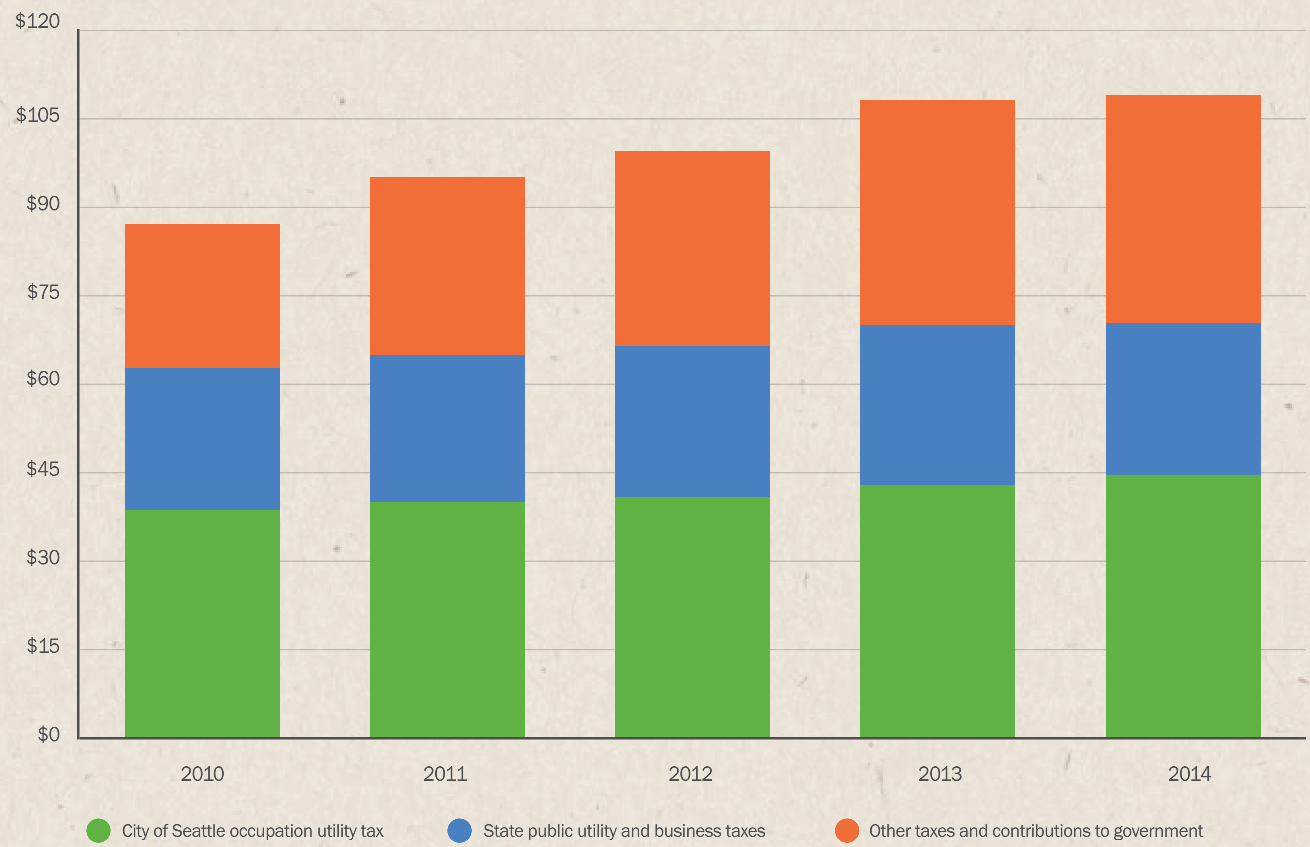
Years ended December 31,	2014	2013	2012	2011	2010
Taxes					
City of Seattle occupation utility tax	$ 44.6	$ 42.8	$ 40.9	$ 40.0	$ 38.6
State public utility and business taxes	25.7	27.2	25.6	25.0	24.2
Suburban contract payments and other	5.6	5.3	5.3	5.5	5.0
Contract payments for government services	4.1	4.0	3.1	3.1	2.6
Total taxes as shown in statement of revenues and expenses	80.0	79.3	74.9	73.6	70.4
Taxes/licenses charged to accounts other than taxes	16.0	15.3	13.7	13.9	13.0
Other contributions to the cost of government [A]	13.0	13.6	10.9	7.6	3.7
Total miscellaneous taxes	29.0	28.9	24.6	21.5	16.7
Total taxes and contributions	$ 109.0	$ 108.2	$ 99.5	$ 95.1	$ 87.1

Note: Electric rates include all taxes. The State Public Utility Tax rate for retail electric power sales was 3.8734%. The City of Seattle Occupation Utility Tax rate was 6% for in-state retail electric power sales.

[A] A favorable court decision in early 2011 ruled that 2009 FERC land use fees were overpaid by $3 million. This overpayment was accrued and applied against the 2010 costs.

TAXES AND CONTRIBUTIONS TO THE COST OF GOVERNMENT

(in millions)



EXPENDITURES & SAVINGS *(Unaudited)*

PUBLIC PURPOSE EXPENDITURES *(Unaudited)*

(in millions)

Years ended December 31, 2014	2014	2013	2012	2011	2010
CONSERVATION					
Programmatic conservation expenses [A]					
Non-low income	$ 31.9	$ 29.9	$ 21.9	$ 24.0	$ 28.7
Low income	1.9	2.5	1.8	3.1	1.8
Non-programmatic conservation expenses [B]	7.9	6.7	6.1	5.6	4.0
Subtotal	$ 41.7	$ 39.1	$ 29.8	$ 32.7	$ 34.5
Annual energy savings (megawatt hours) [C]	160,894	138,159	137,374	126,196	141,581
OTHER PUBLIC PURPOSE EXPENDITURES					
Low-income energy assistance [D]	$ 8.1	$ 8.0	$ 8.2	$ 8.7	$ 8.1
Non-hydro renewable resources [E]	30.8	28.3	28.7	26.9	23.9
Subtotal	38.9	36.3	36.9	35.6	32.0
NET PUBLIC PURPOSE SPENDING	$ 80.6	$ 66.7	$ 68.3	$ 66.5	$ 57.0
Revenue from retail electric sales	$ 721.0	$ 698.0	$ 664.3	$ 656.0	$ 624.2
PERCENT PUBLIC PURPOSE SPENDING TO RETAIL ELECTRIC SALES					
Conservation only	5.8%	5.6%	4.5%	5.0%	5.5%
Low-income assistance & non-hydro renewables	4.3%	5.2%	5.5%	5.4%	5.1%
Total	10.0%	10.8%	10.0%	10.4%	10.6%

[A] Programmatic conservation expenditures are deferred and amortized over a 20-year period in accordance with City Council-passed resolutions and Statement No. 62 of the GASB, Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB & AICPA Pronouncements. Non-low income programmatic conservation includes expenditures for program measures, customer incentives, field staff salaries, energy code enforcement, and direct program administration. They do not include expenditures related to solar or other renewable programs. Low-income programmatic conservation includes these types of expenditures for the Department's HomeWise and Low-Income Multifamily Programs.

[B] Non-programmatic expenditures include program planning, evaluation, data processing, and general administration. These expenses are not associated with measured energy savings.

[C] Energy savings are from completed projects in that year include those from Northwest Energy Efficiency Alliance, residential behavior programs and applicable Transmission & Distribution benefit.

[D] Low-income assistance includes rate discounts and other programs that provide assistance to low income customers.

[E] Non-hydro renewable resources include power generated from the Burlington Biomass, Columbia Ridge Biogas, King County West Point Biogas Cogeneration Plant, and Stateline Wind Project which are funded from current revenues.

ANNUAL ENERGY SAVINGS THROUGH CONSERVATION

(megawatt hours)

Seattle City Light

700 Fifth Avenue Suite 3200
PO Box 34023
Seattle, WA 98124-4023

http://bit.ly/1q3SJds