COMMERCIAL PAPER OFFERING MEMORANDUM

SOUTHERN MINNESOTA MUNICIPAL POWER AGENCY

POWER SUPPLY SYSTEM COMMERCIAL PAPER NOTES, SERIES B

THE AGENCY

Southern Minnesota Municipal Power Agency (the "Agency") is a municipal corporation and political subdivision of the State of Minnesota, incorporated on June 2, 1977 under Minnesota Statutes, Chapter 453 as amended (the "Act"). The Agency was organized under an agreement (the "Agency Agreement") among member municipalities (the "Members") for the purpose of providing an adequate, economical and reliable supply of electric energy to its membership. Under the Act, the Agency is empowered, among other things, to (i) acquire, construct and operate generation and transmission facilities, (ii) purchase, sell, exchange and transmit electric energy within and outside the State of Minnesota, and (iii) issue its obligations to carry out any of its corporate purposes and powers. The Agency may exercise the power of eminent domain in the purchase of property. Minnesota property of the Agency is exempt from property taxes; however the Agency is required to make payments in lieu of taxes in the amounts which would be payable as taxes if its property were owned by a private person. The Agency does not have any taxing power.

The Agency's Members consist of the following eighteen Minnesota municipalities, each of which owns and operates an electric utility system: Austin, Blooming Prairie, Fairmont, Grand Marais, Lake City, Litchfield, Mora, New Prague, North Branch, Owatonna, Preston, Princeton, Redwood Falls, Rochester, Saint Peter, Spring Valley, Waseca, and Wells. The Agency has entered into power sales contracts with each of the Members, as described further below.

The Agency's organizational structure consists of the following: (1) a representative from each Member municipality (collectively, the "Member Representatives"), (2) a seven member Board of Directors (the "Board") comprised of Member Representatives and (3) the Agency's staff (the "Staff"). Policy decisions are made by the Board. In certain instances, decisions of the Board must be approved by the Member Representatives, and certain other decisions are reserved solely to the Member Representatives. The Executive Director & CEO and Staff are charged with the responsibility of executing decisions of the Board and Member Representatives. Under the Agency Agreement, the Member Representatives from the three Members with the greatest number of votes under the weighted voting formula in the Agency Agreement (currently Rochester, Austin and Owatonna) each have a seat on the Board. Rochester and Austin, two of the three Members which have declined to renew their Power Sales Contracts (as defined and described under "POWER SALES CONTRACTS" below) beyond 2030, currently account for a majority of the weighted votes. The remaining four Board members are elected by the Member Representatives on the basis of one vote for each Member Representative. Voting on Board matters is based upon one vote per Board member.

THE POWER SUPPLY SYSTEM

Resources.

Sherco 3. The Agency owns a 41 percent undivided ownership interest in the Sherburne County Generating Unit No. 3 ("Sherco 3") located at the Sherburne County Generating Station in the City of Becker, Minnesota, with a tested net capability of approximately 910 MW.

Sherco 3 commenced commercial operation on November 1, 1987. Northern States Power Company ("NSP"), a Minnesota corporation and a wholly-owned subsidiary of Xcel Energy Inc. ("Xcel"), owns the remaining 59 percent undivided ownership interest in Sherco 3 and is the construction and operating agent under the Ownership and Operating Agreement between the Agency and NSP. The Agency is obligated to pay 41 percent of the cost of improvements to and fixed operating costs for Sherco 3 and is entitled to 41 percent of the power and energy produced by Sherco 3. The Agency also pays 20% of the cost of improvements and fixed operating costs of certain other facilities, which are used jointly by Sherco 3 and two other generating units owned by NSP located on the same site as Sherco 3. Such percentage is subject to adjustment in the event of the addition of other generating units at the site or other major change to operations. Variable operating costs are generally allocated in accordance with the relative power and energy scheduled and taken by the respective owners.

On October 2, 2015 NSP, the co-owner of Sherco 3, made a filing in its currently pending integrated resource plan with the Minnesota Public Utilities Commission. In this plan NSP proposed, subject to all required approvals, the shutting down of Sherco 1 and 2, the two other coal-fired units located at the Sherburne County Generating Station, in 2026 and 2023, respectively. The Agency has not as yet done an exhaustive analysis of the plan and the impact of the shutdown of Sherco 1 and 2 on the operations of Sherco 3 and the cost of power from Sherco 3. However, based on a preliminary analysis, the Agency does not believe that the shutdown of Sherco 1 and 2 will have a material adverse impact on the operations of and cost of power from Sherco 3.

Sherco 3 operates based on an overhaul cycle of one major planned overhaul every three years. The planned overhaul in the fall of 2011 included a retrofit of the intermediate and high pressure turbine sections intended to increase net power output, without an increase in fuel consumption. In addition, a detailed inspection of the boiler was conducted in order to help identify the remaining useful life of various boiler sections. This information will be used to perform a life cycle analysis of the boiler and plan for future section replacements. A new step-up transformer was also installed to allow for the increased power output due to the new turbine sections. The old step-up transformer has been retained on site for back up purposes.

On November 19, 2011, Sherco 3 experienced a catastrophic failure as the unit was being returned to service following the planned overhaul. The event caused extensive damage to the turbine, generator, exciter and some associated plant systems. No injuries occurred, however two workers were treated for smoke inhalation from a fire associated with the incident.

The nearly two-year long restoration project has been completed and the unit returned to commercial operation in the fall of 2013.

Insurance has covered the vast majority of the costs for repairs.

While Sherco 3 was out of service for restoration following the 2011 failure, the Agency, working with its power marketing partner, The Energy Authority, Inc. ("TEA"), was able to purchase replacement capacity and energy in the forward market and effectively hedge the potential market price exposure.

Subsequent to completion of the restoration project, the Agency joined NSP and certain of the insurance companies that covered the cost of the restoration in filing a lawsuit against General Electric ("GE") based on the findings of the root cause analysis of the turbine failure. The case is currently in the discovery phase and is scheduled for trial in late 2016.

In addition to the GE lawsuit, the insurance companies that provide business interruption insurance to Westmoreland Resources (the entity providing coal to Sherco 3 for both the Agency and NSP) issued a demand for arbitration to Western Fuels Association, Inc. (the entity through which the Agency procures coal and rail service for Sherco 3, "Western Fuels"), NSP and the Agency. Because Sherco 3 was out of operation for approximately two years, it was not burning coal and the Agency/Western Fuels and NSP ceased coal procurement from Westmoreland Resources during the restoration project. The insurers of Westmoreland Resources are seeking to collect from Western Fuels, NSP and the Agency the money it paid out to Westmoreland Resources during the Sherco outage. The parties are negotiating an agreement to toll the arbitration proceeding until completion of the GE lawsuit. The Agency does not expect the outcome of this litigation to have an impact on its finances.

A reduced scope planned overhaul in the fall of 2014 was conducted primarily for warranty inspections and further inspections of the boiler. The overhaul was completed on schedule and within budget.

While Sherco 3's equivalent availability and capacity factors have historically been at or above the national average for similar facilities, these factors have been significantly impacted by this extended outage. For the five-year period of 2010 through 2014, Sherco 3's equivalent availability factor, including unscheduled outages and the planned overhauls, was 54.3 percent with a net capacity factor of 42.3 percent. The national five-year averages for similar-sized coal plants for the period of 2010 through 2014 were 83.0 percent and 69.0 percent, respectively. The national five-year averages for all coal-fired plants for the period of 2010 through 2014 were 83.4 percent and 61.4 percent, respectively. Sherco 3's equivalent availability and net capacity factors were 87.37 percent and 64.7 percent, respectively, for the period January 1 through December 31, 2014.

The steam generator for Sherco 3 is fired with low sulfur, sub-bituminous coal. The Agency and NSP have agreed to provide independently for their respective coal and transportation requirements. The Agency has entered into a contract for the long-term supply of coal for Sherco 3 with Western Fuels. To provide this coal, Western Fuels has a coal purchase agreement with Westmoreland Resources that expires December 2017. The Agency delivers its portion of coal for Sherco 3 primarily with an Agency-owned unit train leased to Western Fuels, which schedules and maintains the required railroad cars. The Agency also uses a share of a Western Fuels leased "pool" train along with three other Western Fuels members. Western Fuels has a contract with Burlington Northern Santa Fe Railroad to provide the rail transportation for delivery of coal to Sherco 3 which will expire on December 31, 2017.

Pollution control equipment has been installed and is operated at Sherco 3 to control sulfur dioxide ("SO_2"), nitrogen oxide ("NO_X"), mercury and particulate matter. These control systems consist of a dry scrubber, low NO_X burners, a sorbent injection system and a bag house, which allow Sherco 3 to meet all existing environmental regulations that pertain to those pollutants.

The disposal of coal ash, or Coal Combustion Residuals ("CCR") from Sherco 3 is authorized under MPCA Permit No. SW-293. The existing fly ash disposal facilities consist of three adjoining solid waste landfill cells covering an area of 94 acres. These cells are lined with a composite liner system consisting of a geosynthetic clay liner overlain by a 60 mil high density polyethylene flexible membrane liner. A leachate collection system is constructed over the base liner designed to contain leachate within the lined area, preventing release to the underlying soil and groundwater. The leachate collection system consists of a permeable sand drainage layer, perforated collection pipes and central collection sumps with leachate pumps. The leachate is eventually pumped to the plant for use in plant operations and is not discharged to the environment. The existing three solid waste landfill cells contain enough capacity to dispose of CCR from Sherco 3 for approximately five to six more years. A new cell #4 which has been permitted and is slated for construction in the 2020 timeframe, will add an additional six to seven years of disposal capacity. Cell #5, which has not yet been permitted, will yield an additional 12 to 13 years of disposal capacity. The site facilities currently have space set aside for up to nine disposal cells. Bottom ash is disposed of separately from fly ash and is collected in temporary settling ponds jointly used by Sherco 1, 2 and 3. The majority of the bottom ash is put to beneficial use in the construction of berms and as road base on the plant site. Bottom ash that is not used is stored in the Sherco 1 and 2 storage ponds located on the plant site.

On June 14, 2011, the U.S. Environmental Protection Agency (the "EPA") issued a Notice of Violation ("NOV") to Xcel and NSP, alleging violations of the Clean Air Act at the Sherburne County Generating Station and at another generating station owned by Xcel. As to Sherco 3, the NOV alleges that a project undertaken at the unit in the mid-2000s required a permit under the New Source Review ("NSR") process. NSP reported that it believes it has acted in full compliance with the Clean Air Act and NSR process. NSP also reported that it believes that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations or are otherwise not subject to the NSR requirements. NSP further reported that it disagrees with the assertions contained in the NOV and will vigorously defend its position.

The Agency attended a meeting between NSP and the EPA in August 2011, at which NSP stated and defended its position in relation to the Sherco 3 allegation. The Agency is not aware of additional contact with or communication from the EPA on this matter since that meeting. The current status of this matter is unclear and the potential impact on Sherco 3 has not yet been determined.

The Agency currently has capacity purchase agreements (the "Pass-through Capacity") Purchase Agreements with ten Members that own electric generating resources.

Most of the Agency's Member-owned capacity is covered by Pass-through Capacity Purchase Agreements that provide for the pass-through of certain costs from the particular Member to the Agency. Under the Pass-through Capacity Purchase Agreements, the applicable Member has the responsibility for maintaining the facilities in readily operable condition and to provide the necessary personnel to operate the facilities, while the Agency will (i) have sole authority for hourly scheduling and dispatching of generation; (ii) be responsible for operation and maintenance costs as well as certain renewal and replacement costs as specified under the Pass-through Capacity Purchase Agreements; and (iii) be responsible for procuring all fuel necessary for the facility and for the cost of the fuel and the cost of delivering the fuel to the facility. Under these Pass-through Capacity Purchase Agreements, the Member retains 100 percent ownership of the applicable facility; however, in most cases, all items of equipment, additions to the facility, improvements thereto and other property added to or replacing part of the facility after the date ("Turnover Date") such unit was dedicated to the Agency under such Capacity Purchase Agreement or a previous similar contract (the Turnover Dates vary from 1991 through 1995, depending on the applicable unit) pursuant to the renewal and replacement budget and paid for by the Agency are the sole property of the Agency (subject to certain repurchase obligations of such Member). Under the Pass-through Capacity Purchase Agreements, the Member agrees to indemnify the Agency for certain costs, expenses and/or liabilities incurred by the Agency as a result of any contamination and/or clean-up, imposition of liens and/or third party claims, arising out of the existence or claimed existence of hazardous substance in the plant or on the plant site occurring before the Turnover Date with certain exceptions, all according to the terms of the Pass-through Capacity Purchase Agreements. The Pass-through Capacity Purchase Agreements extend through the earlier of the retirement date of the applicable resource or five years after written notice of termination given by either party. The Agency may shorten the notice requirement to one year if the renewal and replacement budget required to keep the plant operational is determined by the Agency to be uneconomical.

The Agency currently has Pass-through Capacity Purchase Agreements with (i) Owatonna for its gas-fired combustion turbine unit and (ii) Blooming Prairie, Litchfield, Mora, New Prague, Preston, Princeton, Redwood Falls, Spring Valley, and Wells for their respective diesel and dual fuel (diesel and natural gas) units for a total of 85 MW of capacity.

In addition, the Agency has entered into quick-start capacity purchase agreements with Blooming Prairie, Grand Marais, Litchfield, North Branch, Princeton, Redwood Falls, Saint Peter and Spring Valley for new diesel units with ten minute start capability (collectively, the "Quick-Start Capacity Purchase Agreements"). Under these agreements, each such Member finances, builds and operates its unit(s) at its sole expense and provides the output of the unit(s) exclusively to the Agency in exchange for a fixed dollar-per-kilowatt monthly payment to the applicable Member and payment of fuel costs. The Quick-Start Capacity Purchase Agreements are otherwise similar to the Pass-through Capacity Purchase Agreements but have a minimum term of twenty years and can be renewed by the Agency for successive five-year periods thereafter. A total of approximately 57 MW of diesel generation was installed and put into operation during 2003 through 2012 as part of the Quick Start Capacity Purchase Agreements.

In total, approximately 141 MW of dedicated capacity is available to the Agency, including 53 diesel and dual fuel units with an aggregate rating of approximately 124 MW and one combustion turbine unit with an aggregate rating of approximately 17 MW.

The Fairmont Energy Station consists of four new high efficiency natural gas-fired spark-ignited engines totaling 25 MW and two dual fuel (diesel and natural gas) powered generators (12 MW total capacity) that were existing at the time of purchase of the facilities from Fairmont. The four new engines were purchased from Caterpillar Inc. ("Caterpillar"). The new facilities, along with all ancillary fuel, cooling and emissions control systems went into commercial operation in 2014.

The Agency is also in the process of building a 38 MW high efficiency natural gas engine plant, similar to the Fairmont Energy Station, near Owatonna.

In order to meet its power supply obligations, the Agency has also implemented certain demand side management programs and has entered into certain medium-term power purchases from other utilities.

The Agency has entered into a twenty-year agreement with Wapsipinicon Wind Project, LLC ("Wapsipinicon"), a subsidiary of EDF Renewable Energy, Inc. ("EDF"), to purchase the output of a 100.5 MW wind farm located near Dexter, Minnesota expiring on February 20, 2029. EDF is involved in developing clean energy projects in the United States, including in the Midwest.

The Minnesota Legislature's establishment of the Renewable Energy Standard ("RES") in 2007 requires that the Agency purchase or produce increasing percentages of its energy from renewable resources.

The Agency owns six wind turbines (8.5 MW of capacity) installed between 2003 and 2005 and a landfill gas generation project (1.6 MW of capacity) located near Mora, Minnesota and installed in 2012. To meet the RES, the Agency uses energy from: the wind turbines it owns, the Agency-owned landfill gas generator, bio-diesel fueled generation contracted to the Agency, a purchased power agreement from a waste-to-energy facility located in a Member's community, the agreement with Wapsipinicon to purchase the output from a 100.5 MW wind farm located near Dexter, Minnesota, renewable energy certificates ("RECs") purchased from a Member hydroelectric facility, and purchases from the REC market. The combination of production and allowed banking of associated certificates from this portfolio of resources, along with the market purchase of RECs, is projected to meet the Agency's RES requirement through 2020.

The Agency offers its Members the opportunity to purchase RECs for customers interested in supporting renewable energy in addition to that supplied as a part of Agency base energy delivery.

In 2013, the Minnesota Legislature made some changes to Minnesota's net metering rules and established a Solar Energy Standard ("SES"). The 2013 legislation did not change the net metering rules for cooperative and municipal utilities, and the SES only applies to Minnesota's investor owned utilities. While not covered by the SES, the Agency, working with its Board and Members, is developing a strategy for adding solar resources to its portfolio as early as 2016.

Transmission.

General. The Agency's Members are located in the local balancing areas of the Agency, NSP, Great River Energy ("GRE") and Alliant Energy Services ("Alliant Energy"). The Members are connected to the electric transmission systems of the Agency, NSP, Dairyland Power Cooperative ("Dairyland"), GRE and ITC Midwest LLC, a subsidiary of ITC Holdings Corp. ("ITC Midwest"), which purchased the transmission assets of Alliant Energy's Interstate Power and Light in December 2007. Sixteen of the Members have some generating capability located within their respective service areas.

Various transmission lines and associated substation investments have been made by the Agency at a cost of over $140 million (excluding investments related to the CapX 2020 transmission project described below), financed primarily from the proceeds of the Agency's Power Supply System Revenue Bonds (the "Bonds").

The Agency entered into a shared transmission system agreement ("STS Agreement") with Dairyland in 1982. The agreement includes provisions for (i) certain initial payments and investments to compensate the owner of existing transmission facilities for the use of capacity in the existing system; (ii) providing sufficient transmission capacity to deliver the firm power and energy requirements of the utility's customers and the Agency's Members; (iii) formation of the coordinating committee to jointly plan facilities in the geographic areas where the Agency and the utility's service areas overlap; (iv) each utility to construct and own transmission facilities required to be added to the system in proportion to the respective load growth of each system; (v) certain requirements and remedies for maintaining balance of ownership of the transmission facilities included in the shared transmission system; (vi) annual adjustments to be applied to the investment responsibility of a party which is under-invested to recognize escalation in the costs of construction and transmission carrying charges for the use of the over-invested party's system by the under-invested party; (vii) a term of 50 years, after which it continues unless terminated with five years notice by either party; and (viii) operating the shared transmission system and metering of the electricity delivered by the shared transmission system. The Agency and Dairyland are both participants in a CapX 2020 Hampton/La Crosse Line described below, and have agreed that, upon the successful completion and energization of the Hampton/La Crosse Line, both parties' obligations under the STS Agreement will be equalized. The Agency and Dairyland agree that, at that time, the STS Agreement and any future associated investment obligations will be frozen. Although the final segment of the Hampton/La Crosse Line will not be completed and energized until mid to late 2016, both parties agree that future STS Agreement funding obligations will be frozen at the end of 2015.

The remainder of the Agency's loads, not covered by the STS Agreement, are covered by MISO network service.

CapX 2020. In 2006, the Agency joined CapX 2020. Other participants in various aspects of the organization include Central Minnesota Municipal Power Agency, Dairyland, GRE, Minnesota Power, Minnesota Power Cooperative, Missouri River Energy Services, Otter Tail Power Company, Rochester Public Utilities, WPPI Energy and NSP. CapX 2020 was established in 2004 in order to assist in the development of resources needed to promote future electric reliability for Minnesota and the surrounding region. Studies estimated that there could be between 4,000 to 6,000 MW of additional demand in Minnesota and parts of surrounding states by 2020. To accommodate this growth, the transmission "backbone" required major upgrades and expansion.

CapX 2020 has received regulatory approval for three projects, totaling approximately 640 miles of 345 kV line in Minnesota, with short segments in North Dakota, South Dakota and Wisconsin, plus 43 miles of 161 kV lines in Minnesota. The aggregate estimated cost of these facilities is $1.9 billion.

These approved projects include the Hampton – Rochester – La Crosse Transmission Project (previously referred to as the "SE-TC – Rochester La Crosse Transmission Project"). In March 2007, the Agency executed a Project Development Agreement with CapX 2020 and other participating utilities (the "Project Development Agreement") for this project and executed the Project Agreements in December 2012. The Agency is participating with a 13% ownership share in this project. Other project participants include NSP, Dairyland, Rochester Public Utilities and WPPI Energy. This approximately $500 million project includes 120 miles of 345 kV line that runs between a new substation in Hampton, Minnesota (Hampton substation) and a new substation north of Pine Island, Minnesota (North Rochester substation), and continues on to cross the Mississippi River near Alma, Wisconsin. A single circuit 345 kV line was built in Wisconsin to a new substation north of La Crosse, Wisconsin (Briggs Road substation). A new 161 kV line is being constructed between North Rochester substation and the existing Northern Hills substation in northwest Rochester, Minnesota. Also a new 161 kV line was constructed between North Rochester substation and the existing Chester substation in northeast Rochester, Minnesota.

Pursuant to the Project Agreements, NSP is identified as the development manager for this project, responsible for managing the permitting process, engineering, procurement and construction of the project facilities. Most of the Hampton/La Crosse Line has been constructed and some segments have been energized. The final segment of 345 kV line (Hampton – North Rochester) is scheduled to be completed and placed in service in 2016. The Agency's share of the Hampton/La Crosse Line is approximately $75 million.

MISO. The Agency transferred operational control of its transmission facilities to Mid-Continent Independent Transmission System Operator, Inc. ("MISO") on April 1, 2006, when the Agency became a MISO transmission-owning member. MISO oversees approximately 65,800 miles of interconnected, high-voltage transmission lines in fifteen states and the Canadian province of Manitoba. The non-profit MISO provides industry consumers with unbiased regional grid management and open access to the transmission facilities under MISO's functional supervision. The goal of MISO is to optimize the efficiency of the interconnected system, provide regional solutions to regional planning needs, and minimize risks to reliability. Many utilities in the Upper Midwest have become transmission-owning utilities under MISO. These members have transferred the operational control of their transmission systems to MISO and are also under the MISO Open Access Transmission Tariff.

The Agency also participates in the MISO Ancillary Services Market ("ASM"). The MISO ASM began on January 6, 2009. This market allows participants to offer various ancillary services into the marketplace in addition to their normal energy offerings. Generators can offer products such as regulation, spinning reserves, and supplemental reserves. MISO calculates the required amount of each product on a five-minute basis and then awards these bids to the lowest price generators. Given that MISO is now providing these ancillary services to the region, each individual balancing area, such as the Agency's, is no longer required to perform these functions for itself. Participation in the MISO ASM has resulted in savings for the Agency.

Beginning in 2013, MISO converted its monthly capacity market to an annual market. This new annual market, which covers capacity requirements beginning June 1 and ending May 31 of each planning year, requires MISO participants to offer their generating capacity into the auction and to purchase their capacity requirements from the auction. An entity can hedge the cost of capacity from the auction by holding sufficient capacity rights to meet its obligations prior to the auction and offering those rights into the auction at a price that ensures they will clear in the market. For the 2013-2014 and 2014-2015 planning years, the Agency held sufficient capacity rights to meet its capacity obligations through existing generating resources and bilateral contracts, and was able to hedge its exposure to potentially high market clearing prices.

Badger Coulee Project. The Badger Coulee transmission line Project (the "Badger Coulee Project") is a planned 345 kV transmission line to be constructed in Wisconsin by Northern States Power Company, Wisconsin, and American Transmission Company LLC. The line will run from the Briggs Road substation near La Crosse, Wisconsin to North Madison substation near Madison, Wisconsin. By virtue of its ownership in the CapX 2020 Hampton/La Crosse project, the Agency was afforded an opportunity to invest in the Badger Coulee Project. In order to own utility facilities in Wisconsin, an entity must be a Wisconsin utility, as determined by the Public Service Commission of Wisconsin. The Agency formed SMMPA Wisconsin LLC in order to acquire an undivided 6.5% ownership interest in the Badger Coulee Project. The Agency is participating in the Badger Coulee Project through SMMPA Wisconsin LLC in order to derive benefits from owning a share of a multi-value project in the MISO market. Multi-value projects are determined through the MISO transmission planning process to provide broad value to the entire MISO region and therefore the costs are recovered from all entities in MISO. Revenues derived by the Agency from its Badger Coulee Project ownership will help offset costs from other multi-value projects that will be partially borne by the Agency and its Members. The Agency has been in discussions with Rochester and Austin regarding continued participation in the BC Project Interest by these two Members after the expiration of their Power Sales Contracts with the Agency in 2030. If Rochester and Austin agree to participate in the BC Project Interest after 2030, the Agency will finance its rights to entitlement and other benefits from the BC Project Interest on a "project" basis as described below and not under the Resolution. The Agency adopted the Badger Coulee Project Bond Resolution on

August 12, 2015 (the "BC Project Resolution"). Financing for the Agency's rights to entitlement in the BC Project Interest would be secured under the BC Project Resolution and Rochester and Austin would enter into project agreements prior to the incurrence of any long-term debt for the Agency's entitlement to the BC Project Interest. The project agreements would set forth the entitlement to and obligations relating to the BC Project Interest of each of Rochester and Austin after the expiration of each of their Power Sales Contracts in 2030. It is expected that interim financing will initially be obtained pursuant to an agreement between the Agency and U.S. Bank National Association relating to financing the Agency's 100% cost and entitlement share to rights and other benefits from the BC Project Interest. Payments to the bank under the bank agreement are expected to be secured under the BC Project Resolution. Upon the expiration of the bank agreement, the Agency expects to issue long-term bonds under the BC Project Resolution. Until the 2030 expiration dates of the Rochester and Austin Power Sales Contracts, the Members (including Rochester and Austin) will obtain benefits from the Agency's entitlement to the BC Project Interest under the Power Sales Contracts. After 2030, the project agreements entered into by Rochester and Austin will govern each of Rochester's and Austin's benefits from and obligations relating to their respective entitlements to the BC Project Interest. The Agency's payments with respect to costs of BC Project Interest will be payable under the Resolution as Operation and Maintenance Expenses of the System which will be payable prior to payment of Debt Service on the Bonds. The Agency has authorized the issuance under the BC Project Resolution of up to $38.0 million of project debt, including issuance costs, for the acquisition by the Agency of the BC Project Interest. It is expected that the Badger Coulee Project will be completed by 2018.

NERC. The initial set of mandatory reliability standards became enforceable by North American Electric Reliability Corporation ("NERC") in June 2007. As an owner and operator of generation and transmission facilities, the Agency is subject to certain of the NERC reliability standards. The Agency expects that as greater emphasis is placed on securing electrical grid infrastructure, these standards will become stricter and more numerous over time. The financial impact of mandatory compliance with such standards cannot currently be determined. If mandatory reliability standards are increased in the future, a substantial effect on the Agency's operations and financial cash flows could result. In addition, failure to comply with the reliability standards could result in the imposition of fines and penalties.

NERC and its regional entities, such as Midwest Reliability Organization ("MRO"), periodically audit compliance with reliability standards. The Agency was audited by the MRO in February 2015 and there were no findings of violations or potential violations.

POWER SALES CONTRACTS

The Agency has power sales contracts (the "Power Sales Contracts") with each of the eighteen Members.

Term of the Power Sales Contracts. The term of the Power Sales Contracts with Austin, Rochester and Waseca extends to April 1, 2030, and thereafter until terminated upon one year's prior notice by either party. The remaining 15 Members have extended their Power Sales Contracts to expire in 2050, and thereafter until terminated upon one year's prior notice by either party.

Subject to the exceptions and limitations noted below, each Power Sales Contract requires the Agency to sell to the Member, and the Member to purchase from the Agency, all electric power and energy required by such Member for the operation of its municipal electric system for the term of the applicable Power Sales Contract.

Exceptions to Total Requirements Provision. Two exceptions to this total requirements obligation of the Agency and the Members are provided in the Power Sales Contracts. First, each Member may acquire or construct hydro-electric facilities and utilize the capacity thereof, in an amount not exceeding 5 MW at any time, in the operation of its system. Second, three Members, Redwood Falls, Litchfield, and Fairmont, each of which has an allotment of power from Western Area Power Administration ("WAPA"), to purchase power and energy from WAPA, up to 8.9 MW for Redwood Falls, up to 12.7 MW for Litchfield, and up to 0.9 MW for Fairmont. As of December 31, 2014, WAPA supplied approximately 53 percent of Litchfield's power and energy, approximately 60 percent of Redwood Falls' power and energy and approximately two percent of Fairmont's power and energy. In the event that Redwood Falls', Litchfield's, and Fairmont's allocation from WAPA is reduced or terminated, the Agency will be required to supply the power and energy requirements no longer supplied by WAPA.

Limitation on Total Requirements Provisions of certain Members. Two Members have limitations on the amount of power and energy the Agency is required to sell and the Member is required to purchase.

Rochester is still operating under its original Power Sales Contract which provides that, after 1999, the maximum amount of electric power the Agency is required to sell and Rochester is required to purchase is limited to the "Contract Rate of Delivery," as defined therein. Austin will operate under a "Contract Rate of Delivery" of 70 MW, effective January 1, 2016. Rochester's "Contract Rate of Delivery" is 216 MW.

Rights of Other Members to Set Contract Rates of Delivery. All Members other than Rochester and Austin have amended their Power Sales Contracts to extend the total requirements provisions through the terms of their respective Power Sales Contracts. Thus Waseca's total requirements provision extends into 2030 and the total requirements provision for each of the remaining fifteen Members extends into 2050, in each case subject to the right to establish a Contract Rate of Delivery as described below. These amendments to the Power Sales Contracts provide that at any time, unless the Agency is developing a resource for the production or transmission of electric power and energy to be used to supply power and energy under the Power Sales Contracts (a "Power Supply Resource"), the Agency or the Member may, by seven years' notice to the other party, limit the amount of power the Agency is obligated to supply, and the Member is obligated to purchase, to the Member's Contract Rate of Delivery. Under the amended Power Sales Contracts, "Contract Rate of Delivery" is defined to mean the peak demand of the Member, as determined by the Agency, for the calendar year immediately preceding the calendar year in which the Contract Rate of Delivery limitation is to take effect. Neither the Member nor the Agency may give to the other a notice electing to initiate such Contract Rate of Delivery limitation during any period of time when the Agency is developing a Power Supply Resource. Such period shall commence no earlier than the date on which the Agency first enters into a contract to sell Bonds to finance any costs associated with such Power Supply Resource and shall end no later than the earlier of the actual date on which the Agency first receives power and energy or transmission services, as the case may be, from such Power

Supply Resource or the date on which the Agency determines not to proceed with the development of such Power Supply Resource.

Rates. Under the Power Sales Contracts, the Agency is authorized to set rates which will produce revenues sufficient, together with other available funds, to provide for the payment of the Agency's revenue requirements which include, without limitation, debt service on the Bonds and deposits required to be made into the funds established under the Agency's Power Supply System Bond Resolution, adopted May 11, 1983 as amended (the "Resolution"), which would include deposits into the Subordinated Indebtedness Fund established under the Resolution to pay Subordinated Indebtedness. Subordinated Indebtedness under the Resolution includes the Agency's Power Supply System Commercial Paper Notes, Series B (the "Series B Notes") issued pursuant to the Power Supply System Subordinated Indebtedness Resolution No. 2, adopted May 10, 1995, as amended and supplemented (the "Subordinated Resolution"). The Agency's remedies following the failure by a Member to pay any amount due under its Power Sales Contract include discontinuing service to such Member upon fifteen days' advance written notice and, if the amount remains unpaid 120 days or more after the due date, terminating the Power Sales Contract upon 30 days' advance written notice. If the Agency's rates and charges are not sufficient to recover its revenue requirements incurred after such discontinuance or termination, the Agency may revise its rates and charges to its other Members as necessary to provide for such recovery. Pursuant to the Power Sales Contracts, each Member has agreed to maintain rates for the sale of power and energy sufficient to enable it to pay all amounts owing to the Agency thereunder and all other amounts constituting a lien or charge upon the net revenues of its electric or integrated utility system.

Each Member is required to pay for power and energy furnished by the Agency at rates established by the Agency. Such rates are required to be established at a level which will provide for the recovery of all the Agency's revenue requirements, including debt service on the Bonds and other amounts required to be deposited in funds established under the Resolution. The Agency's revenue requirements include amounts required to comply with any rate covenant of the Agency. Under the Resolution, the Agency has covenanted to establish and collect rates, fees and charges for the output of the System which, together with other available Revenues, are reasonably expected to yield Net Revenues for the twelve-month period commencing with the effective date of such rates, fees and charges equal to at least 1.10 times Aggregate Debt Service on Bonds for such period and, in any event, as required, together with other available funds, to pay or discharge all other indebtedness, charges and liens payable out of Revenues (as such terms are defined in the Resolution). For purposes of this covenant, amounts required to pay Refundable Principal Installments (as defined in the Resolution) may be excluded from Aggregate Debt Service to the extent that the Agency intends to make such payments from sources other than Revenues. The Agency is required to review and, if necessary, revise its rates, fees and charges upon the occurrence of a material change in circumstances, but in any case at least once every twelve months.

Members are billed for power and energy furnished by the Agency primarily under the "Base Rate" established under Schedule B of the Power Sales Contracts (the "Base Rate"). The 2015 Base Rate (effective January 1, 2015) consists of a power supply demand charge of $10.66 per kW/month, an on-peak power supply energy charge of $0.05413 per kWh, an off-peak energy charge of $0.04046 per kWh, and a transmission charge of $2.66 per kW/month. Under the 2015 Base Rate schedule, the power supply billing demand for any monthly billing period is the greater of the metered demand coincident to the Agency's highest demand measured for the period or 74 percent of the metered demand coincident to the Agency's highest metered demand measured during the most recent full summer season (June through September). The transmission billing demand for any monthly billing period is 100 percent of the metered demand coincident to the Agency's highest metered demand measured during the most recent full summer season (June through September). Designated on-peak hours are those hours between 10:00 a.m. and 10:00 p.m. Monday through Friday, excluding certain designated holidays. The current Base Rate schedule also includes an energy cost adjustment under which the amounts billed to Members are adjusted each month so that the average rate per kWh, in total, is the same as was budgeted for that month. Changes in the total average rate due to the cost adjustment are limited to 2 mills/kWh per month. The Agency may implement changes in its rates after 90 days' notice to the Members. The Agency's Board approved a 6% across-the-board wholesale power rate increase at its October 16, 2015 meeting effective February 1, 2016. Prior to this increase there had been no increases in the Agency's rates since 2010.

The average cost of power and energy provided by the Agency to the Members through 2014 has increased by 56.2 percent since 2005, an average of slightly over 5 percent per year.

The following table sets forth the annual average cost of power and energy provided by the Agency to the Members along with the annual percentage change for the 2005 through 2014 time period.

Members' Historical Average Cost of Power and Energy from the Agency

Year	Average Cost of Power and Energy (cents/kWh)	Annual Percent Change
2005	4.537	(0.8)
2006	5.343	17.8
2007	5.994	12.2
2008	6.129	2.3
2009	6.631	8.2
2010	7.024	5.9
2011	7.039	0.2
2012	7.089	0.7
2013	7.107	0.3
2014	7.086	(0.3)

The Average Cost of Power increases between 2006 and 2010, shown in the above table, were the result of factors impacting the electric industry as a whole on a regional and national basis. Changes in the Average Cost of Power in 2011 through 2014 were due to kWh sales volume differences between those years and the relative amount of sales on and off peak.

Regulations. The authority of the Agency and each of the Members to determine, fix, impose and collect rates and charges for electric power and energy is not subject to the regulatory jurisdiction of MPUC, or any other regulatory agency or authority of the State of Minnesota, except as the Minnesota Legislature may otherwise provide, including the following: (i) a Member may elect to have its accounting and depreciation practices regulated by the MPUC, (ii) ten percent of the consumers located outside the city limits of a Member or 25 such consumers, whichever is less, may petition the MPUC with respect to rates charged by such

Member, (iii) the MPUC may set rates of a Member for certain purchases of electric energy from and sales of electric energy to qualifying cogeneration and small power production facilities if the Member has not adopted rules consistent with rules of the MPUC on cogeneration and small power production, (iv) each Member is required to spend and invest operating revenues from the sale of electricity for energy conservation improvements, (v) Members are required to adopt a distributed generation tariff addressing issues included in a MPUC order on that subject, and (vi) involuntary disconnection of a residential customer by a Member during cold weather periods (October 15 to April 15) and during periods of excessive heat declared by the National Weather Service is subject to restrictions imposed by Minnesota statutes.

As subdivisions of a state, the Agency and the Members are exempt from status as "public utilities" under the Federal Power Act. As a result, rates and charges for the sale or transmission of electricity by the Agency or the Members are not subject to regulation by FERC, except with respect to (1) transmission service that is ordered by FERC under the Energy Policy Act of 1992 and (2) sales of electricity to qualifying cogeneration and small power production facilities as mandated by Section 210 of the federal Public Utility Regulatory Policies Act of 1978.

The Members are required to spend and invest 1.5 percent of their gross operating revenues on energy conservation improvements. The Members are also required to establish and satisfy an annual energy savings goal of 1.5 percent of gross annual retail energy sales. The Minnesota Legislature has also declared that annual energy savings of 1.5 percent are a part of the state's energy policy. By agreement, the Agency may perform Member conservation obligations in the aggregate, and does so for 15 Members. Each Member must file a conservation improvement program report on its energy conservation efforts with the Department of Commerce (now the Division of Energy Resources ("DER")) annually. DER is authorized to make recommendations to increase the effectiveness of these conservation plans.

In 2001, the Minnesota Legislature established a REO applicable to municipal power agencies (such as the Agency), investor-owned utilities and electric cooperative association generation and transmission utilities. The REO was modified in 2007 to create a mandatory RES, requiring such utilities to achieve seven percent of energy produced from renewable resources by 2010, twelve percent by 2012, seventeen percent by 2016, twenty percent by 2020 and 25 percent by 2025. Additionally, the MPUC was authorized to establish a program for tradable RECs which can be used to satisfy the REO and RES. The MPUC participated with other regulatory bodies in the Midwest to create the Midwest Renewable Energy Tracking System ("M-RETS").

The MPUC established that M-RETS would be the compliance vehicle for the RES and that all covered utilities, including the Agency, must register all their renewable energy generation units with M-RETS. By May 1 of each calendar year, covered utilities, including the Agency, must retire a sufficient number of RECs into their M-RETS retirement account to demonstrate compliance. Compliance reports are filed with the MPUC by June 1 of each calendar year. The MPUC is directed to enforce REO and the RES obligations and may impose financial penalties for violations of its orders. In 2009, legislation required utilities covered by the REO/RES, including the Agency, to file with the MPUC, a standardized contract for the purchase of electricity from wind power projects with a name plate capacity of 5 MW or less. The Agency has filed a standardized contract with the MPUC.

In the Next Generation Energy Act, the Minnesota Legislature specifically addressed GHG emissions. It declared a goal for Minnesota to reduce GHG emissions statewide to a level fifteen percent below 2005 levels by 2015, 30 percent below 2005 levels by 2025 and 80 percent below 2005 levels by 2050. A group of state agencies was directed to promptly submit to the Minnesota Legislature a climate change action plan. Effective August 1, 2009, a moratorium was declared on the construction of new coal-fired plants and transmission facilities supporting such plants, on importation of energy from new coal-fired plants in other states and new long-term power purchase agreements that would increase power sector carbon dioxide ("CO_2") emissions. The moratorium will run until a comprehensive federal or state law or rule is enacted or adopted which will limit and reduce power sector CO_2 emissions or until the moratorium is repealed. The North Dakota Attorney General's Office filed suit in Federal Court challenging the Next Generation Energy Act's import restrictions under the Commerce Clause of the U.S. Constitution. In April 2014, a Federal judge ruled in favor of North Dakota. The State of Minnesota, joined by a number of other entities, appealed the decision and the appeal process is ongoing.

The Next Generation Energy Act further refines the state's energy policy to include (1) reducing per capita use of fossil fuel as an energy input by fifteen percent in the year 2015 through increased energy efficiency and renewable energy and (2) 25 percent of total energy used in the state be derived from renewable energy resources by 2025.

The Minnesota Legislature also directed two studies to address the potential for the development of approximately 1,200 MW of new distributed renewable electric generation throughout Minnesota in units with capacities between 10 MW and 40 MW utilizing renewable energy technology. The Agency participated in the studies' working groups along with other Minnesota electric utilities.

In response to legislation, the Agency has continued the development of its renewable portfolio which is currently in excess of the requirement. In 2013, the Minnesota Legislature directed that a renewable integration study be performed to assess the impacts of increasing the RES from 25 percent in 2025 to 40 percent by 2030. The study was completed on October 31, 2014 and concluded that the addition of wind and solar (variable renewable) generation to supply 40 percent of Minnesota's annual electric retail sales can be reliably accommodated by the electric power system. The results show that, with upgrades to existing transmission of approximately $373 million, the power system can be successfully operated for all hours of the year (no unserved load, no reserve violations, and minimal curtailment of renewable energy) with wind and solar resources increased to achieve 40 percent renewable energy in Minnesota and with current renewable energy standards fully implemented in neighboring MISO North/Central states. Further analysis would be needed to ensure system reliability at 50 percent of Minnesota's annual electric retail sales from variable renewables. With wind and solar resources increased to achieve 50 percent renewable energy in Minnesota and 25 percent renewable energy in MISO North / Central (10 percent above current renewable energy standards in neighboring states), production simulation results show that, with significant transmission upgrades and expansions in the five state area costing approximately $3 billion, the power system can be successfully operated for all hours of the year (no unserved load, no reserve violations, and minimal curtailment of renewable energy). The study was concluded prior to the release of the EPA's final rule on the Clean Power Plan and as such did not include any specific analysis as to potential impacts of the Clean Power Plan on generation portfolios or the transmission system that may arise from implementation of EPA's final rule. The Agency participated as a member of the technical review committee along with other Minnesota utilities.

Legislation has also focused on encouraging smaller community based energy development ("CBED") facilities, primarily wind development. This legislation requires all investor-owned utilities, municipal power agencies, and generation and transmission cooperatives to implement CBED tariffs, in order to encourage the development of CBED projects. The purpose of the legislation is to optimize local, regional, and state benefits from renewable energy development and to facilitate widespread development of community-based renewable energy projects throughout Minnesota. This is done by developing "front-end" loaded twenty-year power purchase agreements where developers would receive higher payments in the first ten years of the agreement and lower payments during the remaining ten years of the agreement.

In an effort to encourage additional distributed generation, particularly solar, the 2013 Legislature made changes to Minnesota's net metering rules and established a Solar Electric Standard ("SES") which applies only to investor-owned utilities. The SES requires investor owned utilities to derive 1.5% of retail electric sales from solar by 2020. Thresholds for qualifying projects for investor-owned utilities was raised from 40kW to 1000kW. Net metering rules for cooperative and municipal utilities remain unchanged at 40kW. While not covered by the SES, the Agency, working with its Board and Members, is developing a strategy for adding solar resources to its portfolio as early as 2016.

In 2005 the Minnesota Legislature passed an Omnibus Energy bill that focused on the need for building a stronger transmission backbone. That legislation provided rate recovery for investor-owned utilities prior to the completion of a transmission project, including recovery for construction work in progress. This legislation gave CapX 2020 the ability to move forward because investor-owned utilities are now certain they will be able to recover project costs and those costs can begin to be recovered prior to completion of projects.

In 2015, the Legislature made further changes to Minnesota's net metering rules that would allow municipal utilities and electric cooperative associations to charge an additional fee to qualifying facilities of 40 kW or less to recover fixed costs not already being recovered through existing rates. The fee must be "reasonable and appropriate" for that class of customer based on the utility's most recent cost of service study. The changes also allow a net metering customer with a facility having a capacity below 40 kW that is interconnected with a cooperative association or municipal utility to elect to be compensated for power sold to the utility via a kilowatt-hour credit on the customer's bill that is carried forward each month. Any kilowatt-hour credits carried forward by the customer cancels at the end of the calendar year with additional compensation.

The 2015 Legislature also extended a statutory provision through June 30, 2017, that allows the Minnesota Department of Commerce ("MDOC") to assess up to $1 million per fiscal year on utilities, including generation and transmission cooperative electric associations and municipal power agencies, for MDOC's activities representing the interests of Minnesota energy consumers before regional, national, and international bodies that make energy policy decisions that affect Minnesota.

In 2006 the Minnesota Legislature passed the Minnesota Mercury Emissions Reduction Act, which targeted 90% mercury removal from Minnesota's largest electric generation facilities, including Sherco 3. While not specifically targeted by the requirement, the Agency worked with Xcel to submit a mercury reduction plan for Sherco 3. Control equipment was installed in 2010, well in advance of proposed federal mercury standards.

Environmental Matters.

The operations of electric utilities, including the Agency's operations and the operations of the electric utility systems of the Members, are subject to environmental regulation. Federal, state and local environmental standards and procedures that regulate Sherco 3 and other forms of generation and transmission facilities used by the Agency are subject to change. These changes may arise from continuing legislative, regulatory and judicial action regarding such standards and procedures. The Agency cannot predict at this time whether any additional legislation or rules will be enacted at the state or federal level that will affect the Agency's operations or the operations of the Members, and if such rules or laws are enacted, what the cost of such actions to the Agency or the Members might be in the future. Consequently, there is no assurance that the units in operation or contemplated herein will remain subject to the regulations currently in effect, will always be in compliance with future regulations or will always be able to obtain all required operating permits. An inability to comply with environmental standards could result in reduced operating levels, higher operating costs or the complete shutdown of individual non-compliant electric generating units.

Additionally, when changes or projects at an Agency facility need regulatory approvals, the timeline for obtaining such approvals is uncertain, and there may be additional or more stringent requirements for the final approvals than were originally anticipated. This can result in higher capital or operating costs for a project, and additional costs due to delays in implementation. It is also possible that approval for a particular project could be denied, or that conditions placed on a project's approval could cause the Agency to reconsider its decision to proceed with such project.

Acid Deposition, Clean Air Act Title IV. Title IV of the Federal Clean Air Act (the "Clean Air Act") contains provisions for allocating emission allowances to power plants based on historical or calculated levels. An allowance is defined as the authorization to emit one ton of SO_2. The Agency has an ownership interest in Sherco 3 (the "Affected Unit"), which is subject to Title IV restrictions. The EPA has issued rules allocating SO_2 allowances to Affected Units.

Based on analyses of future SO_2 emissions from the power supply system and the allowances allocated by the EPA with respect to the Affected Units, the Agency believes that it has received sufficient allowances for the operation of Sherco 3, at projected capacity factors well into the future. The Agency believes that there will not be significant future operating or maintenance expenses or additional capital expenditures for any pollution control equipment required to meet the SO_2 allowance provisions of Title IV.

Also under Title IV, the EPA developed annual NO_X emission standards for all coal-fired units based on low NO_X burner technology. As with the SO_2 control programs, compliance was to be achieved in two stages: Phase I and Phase II. The Agency neither owns nor has under contract any Phase I units. The Agency has an ownership interest in one Phase II unit, Sherco 3. Sherco 3 is currently meeting the Phase II NO_X requirements.

Cross-State Air Pollution Rule. On July 6, 2011, the EPA promulgated the Cross-State Air Pollution Rule ("CSAPR"), which imposed federal requirements on air pollution emissions that cross state lines. CSAPR was intended to reduce power plant emissions that contribute to ozone and fine particle pollution. CSAPR requires a total of 28 states to reduce SO_2 and NO_X emissions to assist in attaining clean air standards. The EPA issued a supplemental rulemaking on December 15, 2011 to require certain states to reduce summertime NO_X emissions under CSAPR. After a series of legal challenges, CSAPR became effective January 1, 2015. Sherco 3 is subject to the SO_2 and NO_X emissions limits, but is not subject to the summertime NO_X rules. The Agency and NSP hold sufficient emission allowances to address emissions at Sherco 3 with existing control equipment and without significant future operating or maintenance expenses. On July 28, 2015, EPA issued a final Notice of Data Availability, detailing 2015 allowance allocations for new units under Phase 1 of the regulations; no allowances were granted to Minnesota during the Phase 1 period. The EPA has not yet announced allowances for units under Phase 2 of the program.

Mercury and Air Toxics. In December 2011, EPA finalized its Mercury and Air Toxics Standards ("MATS"), which established maximum achievable control technology limits for certain hazardous air pollutants at coal and oil-fired electric generating units. For coal units, the rule set stringent emission limits to control various hazardous air pollutants such as mercury, non-mercury metals and acid gases, and specified work practice standards to control organics and dioxins. Affected generating units had until April 16, 2015 to comply, unless they obtained extensions. After industry challenged the MATS rule, the U.S. Court of Appeals for the District of Columbia upheld it in April 2014. However, on June 29, 2015, the Supreme Court overturned the D.C. Circuit's decision, finding that the EPA failed to properly consider costs when promulgating the rule, and remanding the case to the D.C. Circuit and EPA for further proceedings. The results of this remand on the implementation of the MATS program is unclear, but the remand could result in a new or modified final rule.

In 2006, the Minnesota Legislature enacted the Mercury Emissions Reduction Act that calls for an up to 90 percent reduction by December 31, 2009 for the first unit and December 31, 2010 for the second unit of mercury emissions from certain dry scrubbed units owned by investor-owned utilities. In 2007, Xcel filed with the MPUC a mercury reduction plan for Sherco 3 pursuant to Minn. Stat. §216B.682 of the Mercury Emissions Reduction Act. Under the plan, Xcel installed in 2009 a sorbent injection system to remove approximately 81–90 percent of the mercury, when measured on a fuel input basis. The Agency's share of the operation and maintenance costs of this system is negligible. The Agency believes that the existing mercury reduction system, scrubber technology, and baghouse should favorably position Sherco 3 relative to future EPA mercury, acid gas, and non-mercury metals standards, including a new MATS rule after the D.C. Circuit Court of Appeals and EPA act on the remand.

National Ambient Air Quality Standards ("NAAQS") . The Clean Air Act requires the EPA to set NAAQS for six common air pollutants: particulate matter, ground-level ozone, carbon monoxide, SO_2, NO_X and lead. Many of the NAAQS have recently been revised or are in the process of being revised to be more stringent. For example, in December 2014 EPA proposed more stringent standards for the ozone NAAQS. Recently, EPA has also adopted new fine particulate matter NAAQS and is in the process of implementing the 2010 SO_2 NAAQS. More stringent NAAQS, such as this proposed ozone NAAQS or the fine particulate matter NAAQS, could cause certain areas in the Minnesota or surrounding states to be reclassified as "nonattainment," possibly requiring additional emissions reductions from Agency facilities, like Sherco 3, to bring those areas into "attainment." The costs and impacts of any additional pollution control equipment that could be required due to new or revised NAAQS cannot be determined at this time.

Prevention of Significant Deterioration ("PSD"). The Clean Air Act requires persons constructing new major air pollution sources or implementing significant modifications to existing air pollution sources to obtain a permit prior to such construction or modifications. Significant modifications include operational changes that increase the emissions expected from an air pollution source above specified thresholds. In order to obtain a permit for these purposes, the owner or operator of the affected facility must undergo "new source review," which requires the identification and implementation of Best Available Control Technology ("BACT") for all regulated air pollutants and an analysis of the ambient air quality impacts of a facility. EPA has periodically announced specific enforcement programs targeting electric utilities on the basis that equipment replacement and other plant refurbishments made to coal-fired power plants occurred without completing a required new source review under the PSD program. Under Section 114 of the Clean Air Act, the EPA has the authority to request from any person who owns or operates an emission source, information and records about operation, maintenance, emissions, and other data relating to such source for the purpose of developing regulatory programs, determining if a violation occurred (such as the failure to undergo new source review), or carrying out other statutory responsibilities.

Regional Haze. The regional haze program is designed to address widespread haze that results from emissions from a multitude of sources. EPA's regional haze rule requires the development of plans for imposing emissions reductions on sources in the state to improve visibility in national parks and wilderness areas, including upon electric generating units. The State of Minnesota developed a State Implementation Plan effective until 2018 that is intended to reduce emissions of particulate matter, SO_2 and NO_X to reduce haze. Although Minnesota's plan did not require additional control equipment at Sherco 3, EPA's approval is the subject of an appeal pending before the 8th Circuit Court of Appeals. If the court were to reverse EPA's approval of Minnesota's plan, EPA would need to re-evaluate Minnesota's plan and that might result in a revised SIP amendment. Future implementation plans or plan revisions may apply directly to Sherco 3 and may adversely affect output or increase their capital or operating costs in order to achieve or maintain compliance. However, any potentially required upgrades or costs cannot be determined at this time.

Reasonably Attributable Visibility Impairment ("RAVI"). The RAVI rules are intended to address observable impairment from a specific source such as a distinct, identifiable plume from a source's stack to a national park. In December 2012 environmental groups sued the EPA to try to force the EPA to require NSP to install Best Available Retrofit Technology ("BART") at Sherco 1 and 2 using the RAVI rules. The case was settled in 2015 without NSP having to install additional emissions control equipment, in part, by NSP and the Agency agreeing to accept a reduction in the emission limit for SO_2 emissions for Sherco 3 that would be achieved by implementing changes in the operation of the Sherco 3 scrubber. Implementation of the settlement requires a rulemaking to be completed by EPA, which introduces uncertainty as to the timing and final contents of a final rule.

Climate Change. The EPA regulates greenhouse gas emissions as "air pollutants" under the Clean Air Act. Under current regulations, major stationary sources and sources that undergo major modifications must complete New Source Review ("NSR"), which requires those sources to obtain pre-construction permits and implement BACT or lowest achievable emission rates. Permits issued under NSR, in certain circumstances, may impose greenhouse gas emissions standards and control or mitigation requirements. These regulations could affect the ability to add new capacity or implement major modifications of fossil fuel-fired facilities.

On August 3, 2015, the EPA released final regulations, the Clean Power Plan, which set a schedule under which states are required to submit plans to reduce greenhouse gas emissions from existing fossil fuel-fired power plants. The rules are effective 60 days after publication in the Federal Register, which has not yet occurred. The regulation, referred to by EPA as the CPP, was published in the Federal Register on October 23, 2015 as described below.

On October 23, 2015, EPA published three regulations in the Federal Register:

(1) A final regulation (referred to by EPA as the CPP), "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," establishing emission guidelines for states to follow in developing plans to reduce CO_2 emissions from existing fossil-fueled electric generating units. The regulation sets CO_2 emission performance rates representing the best system of emission reduction approach for two subcategories of existing fossil fuel-fired electric generating units—fossil fuel-fired electric utility steam generating units and stationary combustion turbines, sets alternative state-specific CO_2 goals reflecting the CO_2 emission performance rates, and provides guidelines for the development, submittal, and implementation of state plans to demonstrate achievement of the performance rates or goals. EPA's final guidelines require that the state plans meet interim CO_2 performance rates or goals between 2022 and 2029 and final rates or goals in 2030 and beyond.

(2) A final regulation, "Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units," establishing standards for emissions of CO_2 for newly constructed, modified, and reconstructed affected fossil fuel-fired electric generating units. The regulation sets separate standards of performance for new, modified, and reconstructed fossil fuel-fired electric utility steam generating units and fossil fuel-fired stationary combustion turbines.

(3) A proposed regulation, "Federal Plan Requirements for Greenhouse Gas Emissions From Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations." This proposal would establish a federal plan to implement the final CPP regulation for states that do not submit an approvable state plan to EPA. This federal plan proposal presents two approaches, a rate-based

emission trading program and a mass-based emission trading program. The proposal presents model trading rules that states can adopt or tailor for implementation of the final CPP regulation. EPA is accepting comments on the proposal until January 21, 2016.

The Minnesota Pollution Control Agency began stakeholder group meetings in February of 2015 to begin the process of developing a SIP with the goal of having it prepared for potential submission to the EPA in the summer of 2016. The final rule allows states to make an initial filing in September 2016 and request an extension to file the final state SIP until September 2018.

The Clean Power Plan is one of the most complex and wide ranging regulations ever promulgated by EPA under the Clean Air Act, and is based upon limited statutory authorization. Numerous petitions for review and motions for stay have been filed with the D.C. Circuit, contesting the CPP regulations. The outcome of any challenges cannot be determined at this time. Until legal challenges to the regulations are resolved and the Minnesota Pollution Control Agency submits and EPA approves a state plan to implement the CPP and related rules, it is too early to make a final assessment of the financial and operational impacts of the CPP to Agency's generating resources. However, it could have a material impact on operations, including increased operating costs, additional investment in new generation (natural gas and renewables), investment in energy efficiency programs and decreased operation, or closure of coal-fired plants.

Additional regulatory restrictions on the use of coal or emissions of greenhouse gases are foreseeable, either under current legislative authority, or as a result of future federal or state legislation, judicial determinations or international agreements. The Agency's electricity generating operations could be materially affected by such regulations. The impact to operations will depend on the development and implementation of applicable regulations and available technologies and cannot be determined at this time.

Clean Water Act. The federal Clean Water Act regulates the discharge of wastewater and storm water through the National Pollutant Discharge Elimination System ("NPDES") program. The NPDES permit program covers facility-specific storm water and wastewater discharge streams, construction storm water, aquatic life protection and water body impairments. The federal and state water quality regulations require owners and operators of facilities to implement certain best management practices and treatment technologies to meet discharge limits and protect existing water sources for drinking, recreation, agriculture and industrial use. These regulations require continual evaluation, including monitoring and sampling of discharge and background water quality, to ensure protection of water sources for existing and proposed facilities or projects. Additional pollution control or mitigation requirements may be imposed by the regulating authority for waters deemed by the state not to meet the water quality standards applicable to designated uses.

Section 316(b) of the Clean Water Act requires the EPA to ensure that the location, design, construction and capacity of cooling water intake structures for power plants reflect the best technology available to protect aquatic organisms from being killed or injured by impingement or entrainment. In May 2014, the EPA issued final regulations establishing standards for cooling water intake structures at existing large generating facilities. The rule provided several compliance alternatives for existing plants such as using existing technologies, adding fish protection systems or using restoration measures. Sherco 3 is the only Agency facility to which these regulations applies. NSP, as the operating agent of Sherco 3, is required to submit general information about the existing intake system design and characterization of the water source (the Mississippi River), but because Sherco 3 uses a closed-cycle cooling system, no additional improvements or upgrades are anticipated as a result of these regulations.

In addition to the Clean Water Act, the federal Oil Pollution Act ("OPA") imposes clean-up liability for release of oil or petroleum to surface waters and requires the implementation of pollution prevention and response strategies. Compliance with OPA requires facilities to implement a spill prevention, control and countermeasure program. The Agency has spill prevention plans in place for all substation and generation sites where such plan is required and has contracted with an entity specializing in clean up, countermeasures and reporting to address any spills that may occur.

Other Environmental Matters. The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("CERCLA" or "Superfund"), requires cleanup of sites from which there has been a release or threatened release of hazardous substances and authorizes the EPA to take any necessary response action at Superfund sites, including ordering potentially responsible parties ("PRPs") liable for the release to take or pay for such actions. PRPs are broadly defined under CERCLA to include past and present owners and operators of, as well as generators of wastes sent to, a site. Past releases at the Agency's facilities or at off-site locations may result in liability for cleanup or removal of hazardous substances at these locations. As a result, the Agency may incur substantial, but presently unknown, costs as a participant in the cleanup of such sites.

Coal Ash. Sherco 3, in which the Agency owns an undivided ownership interest, produces coal ash waste that requires disposal. For a discussion of the disposal of coal ash at Sherco 3, see "THE POWER SUPPLY SYSTEM – Power Supply Resources – Sherco 3" herein.

On April 17, 2015, the EPA published final regulations governing the disposal of CCRs, which regulated CCRs as ordinary solid waste, and not as regulated "hazardous waste." The rule establishes technical requirements for the construction and management of impoundments for CCRs, including requirements for liners under any expansion or extension of a coal ash repository. The rule requires monitoring of groundwater, and could trigger requirements for response actions in the event that CCR constituents are found to have migrated to soil or groundwater from a CCR repository. The CCR requirements will affect future expansions or modifications of our coal ash repositories, and may require action with respect to current facilities if releases to soil or groundwater are detected. The total impact of the rule cannot be determined at this time; it could, however, have a material impact on operations, including increased operating costs.

TEA. At the end of 2005, the Agency entered into a wholesale marketing agreement with TEA, a Georgia nonprofit corporation founded by public power utilities in 1997. Under that agreement, TEA assists the Agency with wholesale marketing activities. Specifically, TEA is exclusively responsible for the Agency's real-time and medium-term energy transactions. TEA brings to the Agency significant expertise in markets such as the MISO market which uses locational marginal pricing. The Agency remains directly involved in energy marketing activities, working closely with TEA on a day-to-day basis. The TEA risk management services are coordinated with the periodic review of the Agency's financial reserves as performed by the Agency's financial advisor, Public Financial Management, Inc.

TEA also provides the Agency with risk management services related to the Agency's power supply portfolio. These services are focused on identifying ways in which the Agency can reduce its cash flow at risk and sustain adequate financial reserves from areas primarily outside of the Agency's control such as, among others, unplanned generating unit outages, market price fluctuations and fuel price fluctuations.

POWER SUPPLY OPERATIONS

The following table set forth below summarizes the growth in the aggregate power and energy requirements of the Members' electric systems during the period 2010 through 2014. In 2015 the Agency's peak demand was 514 MW on September 3.

Members'
Historical Power and Energy Requirements from the Agency
Inlet to Member Systems

	Peak Demand [1]		**Energy**	
Year	(MW)	Percent Change	(MWh)	Percent Change
2010	516	5.1	2,823,926	3.2
2011	529	2.5	2,827,619	0.1
2012	519	(1.9)	2,822,105	(0.2)
2013	522	0.6	2,826,831	0.2
2014	506	(3.1)	2,809,219	(0.6)
Average Annual Compound Growth Rate: 2010-2014:		(0.5)		(0.1)

(1) The peak demand is the sum of the coincident peak demands for each of the Members during the month when the Agency's demand is higher than any other month of the year.

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FINANCIAL OPERATIONS

Below is shown a summary of operations and net position for the three years ended December 31, 2014.

SUMMARY OF OPERATIONS AND NET POSITION

	Years Ended December 31,		
	2014	**2013**	**2012**
Operating revenues			
Power sales	$242,631,302	$ 244,877,804	$ 241,436,566
Rate stabilization (contributions)/distributions	(475,547)	8,131,052	(184,994)
Total operating revenues	$242,155,755	$253,008,856	$241,251,572
Operating expenses			
Production fuel	46,410,022	7,111,814	892,210
Power production	67,471,136	120,112,839	126,608,034
Other operating expenses	56,568,777	49,892,022	44,275,363
Depreciation and amortization	16,339,677	15,232,595	15,729,147
Deferred costs expensed in current period	3,725,759	2,634,378	972,236
Total operating expenses	190,515,371	194,983,648	188,476,990
Operating income	51,640,384	58,025,208	52,774,582
Nonoperating income			
Investment earnings	1,251,575	1,059,704	1,569,104
Miscellaneous income	1,219,580	1,209,449	1,306,908
Total other revenues	2,471,155	2,269,153	2,876,012
Nonoperating other expenses			
Interest expense	12,793,818	16,143,581	19,670,487
Deferred costs expensed in current period	5,129,352	4,511,075	1,347,137
Amortization of long-term debt issuance costs	1,093,474	1,128,501	1,202,645
Amortization of discount/premium on long-term debt	25,646,738	25,013,451	25,033,835
Total nonoperating expenses	44,663,382	46,796,608	47,254,104
Change in net position	$ 9,448,157	$ 13,497,753	$ 8,396,490
Net Position			
Beginning of period	88,942,556	75,444,803	67,048,313
End of period	$98,390,713	$ 88,942,556	$75,444,803

The operating results of the Agency reflect the results of past operations and are not necessarily indicative of results of operations for any future period. Future operations will be affected by factors relating to changes in rates, fuel and other operating costs, environmental regulations, increased competition in the electric utility industry, population and economic growth of the Members, weather and other matters, the nature and effect of which cannot at present be determined. In addition, operating revenues and expenses may fluctuate from year to year, based on the power and energy requirements provided by the Agency to the Members. See "Members' Historical Power and Energy Requirements" herein.

The Agency's highest peak demand was 529 MW in 2011 and peak demand in 2014 was 506 MW. Peak demand is largely a result of the effects of hot summer weather. Energy sales have not increased appreciably from 2011 to 2014. A key reason is that the Agency continues to work with its Members to meet the required 1.5% reduction in annual retail sales as a result of its conservation programs. See “Regulations” herein and “Members’ Historical Power and Energy Requirements” table herein.

In accordance with the Resolution, the Agency establishes rates, which together with other revenues, are reasonably expected to pay its operating costs (not including depreciation and amortization) and at least 1.10 times its Aggregate Debt Service. The Agency defers depreciation and amortization in excess of long term bond principal payments in accordance with Generally Accepted Accounting Principles, which include the Government Accounting Standards Board (GASB) No. 62, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 31, 1989 FASB and AICPA Pronouncements*, which codified all generally accepted accounting principles into one source. GASB No. 62 provides guidance as it relates to the deferral of revenues and expenses to future periods in which the revenues are earned or the expenses are recovered through the rate-making process. See “Summary of Operations and Net Position” above.

Years Ended December 31, 2014 and 2013

Operating revenues, power sales, decreased by approximately $10.9 million between 2014 and 2013. Operating revenues, power sales, consist principally of Member power sales revenue, power sales to nonmembers, other transmission revenue, and contributions to, or distributions from, the Rate Stabilization Account. Sales to nonmembers include the Agency’s participation in the MISO day 2 market.

In 2014, before the effects of contributions made to the Rate Stabilization Account, operating revenues, power sales, decreased by approximately $2.2 million, primarily due to decreases in the member sales by $1.8 million and transmission service agreement revenues by $2.2 million, offset by increases in MISO energy market sales of $1.8 million. In 2013, before the effects of distributions made from the Rate Stabilization Account, operating revenues, power sales, increased by approximately $3.4 million, primarily due to an increase in MISO energy market sales by approximately $1.4 million, by an increase of approximately $1.1 million in transmission revenue, and by an increase in power sales to Members of approximately $0.9 million. There was a net contribution of approximately $0.5 million to the Rate Stabilization Account in 2014 compared with a net distribution of $8.1 million in 2013. Contributions to the Rate Stabilization Account decrease the amount of operating revenues, power sales, whereas distributions from the Rate Stabilization Account increase the amount of operating revenues, power sales as funds are added to, or subtracted from, the Rate Stabilization Account, which is included in deferred inflows.

Other revenues increased by approximately $0.2 million between 2014 and 2013. Other revenues include the Build America Bonds interest subsidy and rental income.

Operating expenses decreased by approximately $4.5 million between 2014 and 2013. Operating expenses consist of production fuel, power production, other operating expenses, depreciation and amortization, and expenses to be recovered in future periods. The decrease observed in 2014, compared with 2013, was the net result of an increase in production fuel expense of approximately $39.3 million with Sherco 3 back on line, offset by a decrease in power production expenses of approximately $52.6 million reflecting reduced energy market purchases with Sherco 3 back on line, an increase in other operating expenses of approximately \$6.7 million (consisting mainly of an increase of approximately \$1.9 million in transmission expenses, an increase of approximately \$3.0 million in Sherco 3 operating and maintenance expenses, an increase in administrative and member services of approximately \$0.8 million and an increase of approximately \$0.6 million of demand side management expenses) and a combined increase of approximately \$2.2 million in depreciation and expenses to be recovered in future periods.

Years Ended December 31, 2013 and 2012.

Operating revenues, power sales, increased by approximately \$11.8 million between 2013 and 2012. Operating revenues, power sales, consist principally of Member power sales revenue, power sales to nonmembers, other transmission revenue, and contributions to, or distributions from, the Rate Stabilization Account. Sales to nonmembers include the Agency's participation in the MISO energy market.

Before the effects of distributions made from the Rate Stabilization Account, operating revenues, power sales, increased by approximately \$3.4 million, primarily due to an increase in MISO energy market by approximately \$1.4 million, an increase of approximately \$1.1 million in transmission revenue, and by an increase in power sales to Members of approximately \$0.9 million. There was a net distribution of approximately \$8.1 million from the Rate Stabilization Account in 2013 compared with a net contribution of \$0.2 million in 2012. Contributions to the Rate Stabilization Account decrease the amount of operating revenues, power sales, whereas distributions from the Rate Stabilization Account increase the amount of operating revenues, power sales as funds are added to, or subtracted from, the Rate Stabilization Account, which is included in deferred inflows.

Other revenues decreased by approximately \$0.6 million between 2013 and 2012. Other revenues include the cash subsidy payments relating to a series of "Build America Bonds" and rental income.

Operating expenses increased by approximately \$6.5 million between 2013 and 2012. Operating expenses consist of production fuel, power production, other operating expenses, depreciation and amortization, and expenses to be recovered in future periods. The increase in 2013 compared with 2012 was the net result of an increase in production fuel expense of approximately \$6.2 million, a decrease in power production expenses of approximately \$6.5 million, an increase in other operating expenses of approximately \$5.6 million (due to a decrease of approximately \$0.6 million in transmission expenses, an increase of approximately \$5.5 million in Sherco 3 operating and maintenance expenses, and an increase of approximately \$0.5 million of other Agency owned generation, a decrease in administrative and member services of approximately \$0.4 million and an increase of approximately \$0.6 million in in-lieu of property taxes) and a combined increase of approximately \$1.2 million in depreciation and expenses to be recovered in future periods.

LITIGATION

There is currently no litigation pending or, to the knowledge of the Agency, threatened in any court to restrain or enjoin the issuance or delivery of any of the Series B Notes or the collection of revenues pledged or to be pledged to pay the principal of and premium, if any, and interest on the Series B Notes or in any way contesting or affecting the validity of the Series B Notes or the Resolution or the power to collect and pledge the revenues to pay the Series B Notes or contesting the powers or authority of the Agency to issue the Series B Notes or adopt the Resolution.

There is currently no litigation pending, nor, to the knowledge of the Agency, threatened in any court which, if determined unfavorably to the Agency would, in the opinion of the Agency, materially adversely affect the financial condition of the Agency.

TAX MATTERS

Orrick, Herrington & Sutcliffe LLP ("Bond Counsel") rendered an opinion on November 19, 2013 to the effect that, based upon an analysis of existing laws, regulations, rulings, and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the Series B Notes when issued in accordance with the Subordinated Indebtedness Resolution, the Issuing and Paying Agency Agreement and the Tax Certificate of the Agency with respect to the Series B Notes (the "Tax Certificate"), will be excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986 (the "Code") and from taxable net income of individuals, estates or trusts for Minnesota income tax purposes. Interest on the Series B Notes is not a specific preference item for purposes of the federal individual and corporate alternative minimum taxes, although Bond Counsel observes that such interest is included in adjusted current earnings when calculating federal corporate alternative minimum taxable income. The amount treated as interest on the Series B Notes and excluded from gross income will depend upon the taxpayer's election under Internal Revenue Notice 94-84. Bond Counsel expresses no opinion regarding any other federal or local tax consequences relating to the ownership or disposition of, or the accrual or receipt of interest on, the Series B Notes.

The Code imposes various restrictions, conditions and requirements relating to the exclusion from gross income for federal income tax purposes of interest on obligations such as the Series B Notes. The Agency has made certain representations and covenanted to comply with certain restrictions designed to ensure that interest on the Series B Notes will not be included in federal gross income. Inaccuracy of those representations or failure to comply with these covenants with respect to the Series B Notes may result in interest on such Series B Notes being included in gross income for federal income tax purposes, possibly from the date of original issuance of such Series B Notes. The opinion of Bond Counsel assumes the accuracy of those representations and compliance with these covenants. Bond Counsel has not undertaken to determine (or to inform any person) whether any actions taken (or not taken) or events occurring (or not occurring) or any other matters coming to Bond Counsel's attention after the date of issuance of the Series B Notes may adversely affect the value of, or the tax status of interest on, such Series B Notes. Accordingly, this opinion is not intended to, and may not, be relied upon in connection with any such actions, events or matters.

Although Bond Counsel is of the opinion that interest on the Series B Notes is excluded from gross income for federal income tax purposes and from taxable net income of individuals, estates or trusts for Minnesota income tax purposes, the ownership or disposition of, or the accrual or receipt of interest on, the Series B Notes may otherwise affect a Note owner's federal or state tax liability. The nature and extent of these other tax consequences will depend upon the particular tax status of the owner or the owner's other items of income or deduction. Bond Counsel expresses no opinion regarding any such other tax consequences.

Future legislative proposals, if enacted into law, or clarification of the Code or court decisions may cause interest on the Series B Notes to be subject, directly or indirectly, to federal income taxation or cause interest on the Series B Notes to be subject to or exempted from state income taxation, or otherwise prevent Beneficial Owners from realizing the full current benefit of the tax status of such interest. The introduction or enactment of any such future legislative proposals, clarification of the Code or court decisions may also affect the market price for, or marketability of, the Series B Notes. Prospective purchasers of the Series B Notes should consult their own tax advisors regarding any pending or proposed federal or state tax legislation, regulations or litigation, as to which Bond Counsel expresses no opinion.

The opinion of Bond Counsel is based on current legal authority, covers certain matters not directly addressed by such authorities, and represents Bond Counsel's judgment as to the proper treatment of the Series B Notes for federal income tax purposes. It is not binding on the Internal Revenue Service ("IRS") or the courts. Furthermore, Bond Counsel cannot give and has not given any opinion or assurance about the future activities of the Agency, or about the effect of future changes in the Code, the applicable regulations, the interpretation thereof or the enforcement thereof by the IRS. The Agency has covenanted, however, to comply with the requirements of the Code.

Bond Counsel's engagement with respect to the Series B Notes ends with the issuance of the Series B Notes, and, unless separately engaged, Bond Counsel is not obligated to defend the Agency or the Beneficial Owners regarding the tax-exempt status of the Series B Notes in the event of an audit examination by the IRS. Under current procedures, parties other than the Agency and their appointed counsel, including the Beneficial Owners, would have little, if any, right to participate in the audit examination process. Moreover, because achieving judicial review in connection with an audit examination of tax-exempt obligations is difficult, obtaining an independent review of IRS positions with which the Agency legitimately disagrees, may not be practicable. Any action of the IRS, including but not limited to selection of the Series B Notes for audit, or the course or result of such audit, or an audit of bonds presenting similar tax issues may affect the market price for, or the marketability of, the Series B Notes, and may cause the Agency or the Beneficial Owners to incur significant expense.

<u>THE SERIES B NOTES</u>

Pursuant to the Subordinated Resolution, the Agency is authorized to borrow and reborrow from time to time up to $68,000,000 at any one time outstanding, evidenced by the issuance of the Series B Notes. The Agency has entered into a Revolving Credit Agreement, dated as of December 1, 2012 (as amended, the "Credit Agreement"), with U.S. Bank National Association ("the Bank") as described under the caption "BANK LIQUIDITY ARRANGEMENTS" below. Proceeds of the Series B Notes will be used to finance and refinance Costs of Acquisition and Construction of the System, provide for the retirement of certain of the Agency's Bonds, and pay principal of and interest on maturing Series B Notes and the Bank Note (as defined in the Credit Agreement) outstanding under the Credit Agreement.

The Series B Notes are direct and special obligations of the Agency secured by and payable solely from amounts in the Commercial Paper Note Payment Account (the "CP Note Payment Account") held by U.S. Bank Trust National Association, formerly known as First Trust National Association (the "Issuing and Paying Agent"), under an Issuing and Paying Agency Agreement with the Agency, dated as of May 10, 1995 (as may be amended from time to time, the "Issuing and Paying Agency Agreement"), and by amounts held in the Subordinated Indebtedness Fund under the Resolution. The pledge of amounts held in the Subordinated Indebtedness Fund is subordinate to the pledge created under the Resolution as security for the Bonds, and is on a parity with any Bank Notes outstanding and with "net" swap payments owed in connection with the Agency's interest rate swap transactions. Amounts in the CP Note Payment Account will consist of proceeds from the sale of the Series B Notes, and borrowings under the Credit Agreement.

The Agency has covenanted in the Resolution and the Subordinated Resolution to establish, charge and collect rates, fees and charges under the Power Sales Contracts which, together with other available revenues are reasonably expected to yield Net Revenues equal to at least 1.10x Aggregate Debt Service, which is debt service on the Agency's Senior Lien Bonds (as defined in the Resolution) and does not include debt service on Subordinated Indebtedness. The Agency is also required by the Resolution and the Subordinated Resolution to produce Net Revenues as shall be required, together with other available funds, to pay or discharge all other indebtedness, charges and liens payable out of revenues under the Resolution.

Under a Dealer Agreement between the Agency and U.S. Bancorp Investments, Inc. ("USBII"), USBII will act as dealer with respect to the Series B Notes. The Series B Notes may be issued in bearer form, without coupons, or under a book-entry system, in denominations of any multiple of $1,000, with a minimum denomination of $100,000. The Series B Notes may bear interest payable at maturity at a maximum rate not in excess of 15 percent per annum, and shall mature not more than 270 days after issuance, but in no event later than the Termination Date (as defined in the Credit Agreement). Interest on the Series B Notes will be calculated on the basis of actual days elapsed and a 365 or 366 day year, as applicable.

The Depository Trust Company ("DTC") will act as the initial securities depository for the Series B Notes to be issued in book-entry form. A single, fully-registered Series B Note has been issued, registered in the name of Cede & Co. (DTC's partnership nominee), to evidence all Series B Notes issued in book-entry form through DTC's book-entry system.

DTC, the world's largest securities depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments from over 100 countries that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). The DTC Rules applicable to its Participants are on file with the Securities and Exchange Commission. More information about DTC can be found at www.dtcc.com and www.dtc.org.

Purchases of Series B Notes under the DTC system must be made by or through Direct Participants, which will receive a credit for the Series B Notes on DTC's records. The ownership interest of each actual purchaser of each Series B Note ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the Series B Notes are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in Series B Notes, except in the event that use of the book-entry system for the Series B Notes is discontinued.

To facilitate subsequent transfers, securities deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co, or such other name as may be requested by an authorized representative of DTC. The deposit of Series B Notes with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Series B Notes; DTC's records reflect only the identity of the Direct Participants to whose accounts such Series B Notes are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to securities deposited with DTC unless authorized by a Direct Participant in accordance with DTC's procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the issuer of such securities as soon as possible after the "record date." The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts securities, such as the Series B Notes, are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

Principal and interest payments on the Series B Notes will be paid to Cede & Co., or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detail information from the Agency or the issuing agent on payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC, nor its nominee, the Agency or the issuing agent, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Agency or the issuing agent, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

DTC may discontinue providing its services as depository with respect to the Series B Notes at any time by giving reasonable notice to the Agency or the issuing agent. Under such circumstances, in the event that a successor securities depository is not obtained, Series B Note certificates are required to be printed and delivered.

The Agency may decide to, upon satisfaction of the applicable procedures with respect to DTC, discontinue the use of the system of book-entry transfers through DTC (or a successor securities depository). In that event, Series B Note certificates will be printed and delivered.

The information in this section concerning DTC and DTC's book-entry system has been obtained from sources believed to be reliable, but the Agency takes no responsibility for the accuracy, completeness or adequacy of such information, or as to the absence of material adverse changes in such information subsequent to the date of this Commercial Paper Offering Memorandum.

BANK LIQUIDITY ARRANGEMENTS

In order to provide liquidity for the payment of principal on maturing Series B Notes, the Agency and the Bank have entered into the Credit Agreement. The Bank may enforce the Agency's obligations under the Credit Agreement and the Bank Note pursuant to the terms of the Credit Agreement.

Capitalized terms used under this caption and not otherwise defined herein have the meanings assigned to such terms in the Credit Agreement. The following does not purport to be a complete summary of the Credit Agreement. Copies of the Credit Agreement are available from the Agency.

In accordance with the terms thereof, the Credit Agreement provides for draws of up to $68,000,000, as such amount may be terminated and reduced pursuant to the Credit Agreement, for payment of the principal amount of the Series B Notes (the "Commitment").

The Credit Agreement will expire on the earliest of (i) November 24, 2017, as such date may be extended pursuant to the terms of the Credit Agreement, (ii) the date the Commitment is reduced to zero pursuant to the terms of the Credit Agreement, or (iii) the effective date of any substitution of the Credit Agreement (the "Commitment Termination Date").

Events of Default

Each of the following events shall constitute an "Event of Default" under the Credit Agreement:

(a) (1) the Agency shall fail to pay (i) interest on any maturing Series B Notes, (ii) any principal of or interest on any Loan (as defined in the Credit Agreement) or the Bank Note when due (whether by scheduled maturity, required prepayment, acceleration, demand or otherwise) (other than payments on Loans or Bank Note due solely as a result of acceleration caused by the Bank pursuant to the paragraphs under the heading "Events of Default" above and "Remedies" below), or (iii) any Facility Fee (as defined in the Credit Agreement) or any other amount payable under the Credit Agreement and, in the case of such Facility Fee or other amount, such failure shall continue for a period of three Business Days (as defined in the Credit Agreement) from the date such obligation was due or (2) the Agency fails to pay, or cause to be paid, when due any other Obligation (as defined in the Credit Agreement) (other than the Obligations described in clause (1) of this paragraph (a));

(b) any representation, warranty or statement made by or on behalf of the Agency in the Credit Agreement or in any Program Document (as defined in the Credit Agreement) to which the Agency is a party or in any certificate delivered pursuant thereto shall prove to be untrue in any material respect on the date as of which made or deemed made; or the documents, certificates or statements of the Agency (including unaudited financial reports, budgets, projections and cash flows of the Agency) furnished to the Bank by or on behalf of the Agency in connection with the transactions contemplated by the Credit Agreement, when taken as a whole, are materially inaccurate in light of the circumstances under which they were made and as of the date on which they were made;

(c) (i) the Agency, as applicable, fails to perform or observe certain terms, covenants or agreements contained in the Credit Agreement; or (ii) the Agency fails to perform or observe any other term, covenant or agreement contained in the Credit Agreement or the Fee Letter (as defined in the Credit Agreement) (other than those referred to in paragraph (a) above and clause (i) of this paragraph (c)) and any such failure cannot be cured or, if curable, remains uncured for fifteen calendar days after the earlier of (A) written notice thereof to the Agency or (B) any Authorized Officer (as defined in the Credit Agreement) having actual knowledge thereof;

(d) the Agency shall (i) fail to pay when due (whether by scheduled maturity, required prepayment, acceleration, demand or otherwise) any principal of or interest on any Senior and Parity Lien Debt (as defined in the Credit Agreement) (other than a failure to pay certain amounts described in the Credit Agreement which have been accelerated pursuant to the terms of the applicable agreement), and such failure shall continue beyond any applicable period of grace specified in any underlying resolution, indenture, contract or instrument providing for the creation of or concerning any Senior and Parity Lien Debt; or any failure to pay principal or interest on any Senior and Parity Lien Debt under any indenture, contract or instrument providing for the creation of or concerning such Senior and Parity Lien Debt shall occur and shall continue after the applicable grace period, if any, specified in such agreement or instrument, if the effect of such failure to pay principal or interest on any Senior and Parity Lien Debt is to accelerate the maturity of such Senior and Parity Lien Debt; (ii) fail to pay when due and payable any principal of or interest on any other Debt (as defined in the Credit Agreement) of the Agency which individually, or in the aggregate, is equal to or exceeds $10,000,000 and such failure shall continue beyond any applicable period of grace specified in any underlying resolution, indenture, contract or instrument providing for the creation thereof or any other default under any resolution, indenture, contract or instrument providing for the creation of or concerning such other Debt, or any other event, shall occur and shall continue after the applicable grace period, if any, specified in such agreement or instrument, if the effect of such default or event is to accelerate the maturity of such other Debt; (iii) default in any payment of any Debt the principal amount of which individually, or in the aggregate, is equal to or exceeds $10,000,000, beyond the period of grace, if any, provided in the resolution, instrument or agreement under which such Debt was created; or (iv) default in the observance or performance of any agreement or condition relating to any Debt the principal amount of which individually, or in the aggregate, is equal to or exceeds $10,000,000 of the Agency or contained in any resolution, instrument or agreement evidencing, securing or relating thereto, or any other event shall occur or condition exist, the effect of which default or other event or condition is to cause any such Debt to become due prior to its stated maturity;

(e) (i) any provision of the Credit Agreement, the Series B Notes, the Bank Note, the Issuing and Paying Agency Agreement, the Resolution or the Subordinated Resolution related to the payment of principal or interest on Series B Notes, the Bank Note or Loans or the pledge of and security interest in the Trust Estate (as defined in the Credit Agreement), the CP Note Payment Account (as defined in the Credit Agreement) or the Subordinated Indebtedness Fund (as defined in the Credit Agreement) shall at any time for any reason cease to be valid and binding or fully enforceable on the Agency as determined by any Governmental Authority (as defined in the Credit Agreement) of competent jurisdiction in a final nonappealable judgment, or (ii)(a) the validity or enforceability of any provision of the Credit Agreement, the Series B Notes, the Bank Note, the Issuing and Paying Agency Agreement related to the payment of principal or interest on Series B Notes, the Bank Note or Loans or the pledge of and security interest in the Trust Estate, the CP Note Payment Account or the Subordinated Indebtedness Fund shall be contested by the Agency or (b) any Governmental Authority having appropriate jurisdiction over the Agency shall make a finding or ruling or shall enact or adopt legislation or issue an executive order or enter a judgment or decree which contests the validity or enforceability of any material provision of the Credit Agreement, the Series B Notes, the Bank Note, the Issuing and Paying Agency Agreement, the Resolution or the Subordinated Resolution related to the payment of principal or interest on the Series B Notes, the Bank Note or Loans or the pledge of and security interest in the Trust Estate, the CP Note Payment Account or the Subordinated Indebtedness Fund, or (c) the Agency shall deny that it has any or further liability or obligation under the Credit Agreement, the Series B Notes, the Bank Note, the Issuing and Paying Agency Agreement, the Resolution or the Subordinated Resolution or (iii) any material provision of the Credit Agreement, the Series B Notes, the Bank Note, the Issuing and Paying Agency Agreement, the Resolution or the Subordinated Resolution other than a provision described in clauses (i) and (ii) of this paragraph (e) shall at any time for any reason cease to be valid and binding on the Agency, or shall be declared in a final nonappealable judgment by any court having jurisdiction over the Agency to be null and void, invalid, or unenforceable, or the validity or enforceability thereof shall be contested by the Agency;

(f) any provision of the Issuing and Paying Agency Agreement, the Resolution or the Subordinated Resolution relating to the security for the Series B Notes or the Bank Note, the Agency's ability to pay the Obligations under the Credit Agreement or under the Fee Letter or the security, rights or remedies of the Bank, or any Program Document to which the Agency is a party, except for any Dealer Agreement (as defined in the Credit Agreement) which has been terminated due to a substitution of a Dealer (as defined in the Credit Agreement), shall cease to be in full force or effect;

(g) one or more final unappealable judgments or orders for the payment of money from the Trust Estate which, individually or in the aggregate, equal or exceed $10,000,000 shall have been rendered against the Agency and such judgment(s) or order(s) shall not have been satisfied, stayed, vacated, discharged or bonded pending appeal within a period of 60 calendar days from the date on which it was first so rendered;

(h) (i) the Agency shall commence any case, proceeding or other action (A) under any existing or future law of any jurisdiction, domestic or foreign, relating to bankruptcy, insolvency, reorganization or relief of debtors, seeking to have an order for relief entered with respect to it, or seeking to adjudicate it a bankrupt or insolvent, or seeking reorganization, arrangement, adjustment, winding-up, liquidation, dissolution, composition or other relief with respect to it or its debts or (B) seeking appointment of a receiver, trustee, custodian or other similar official for it or for all or any substantial part of its assets, or the Agency shall make a general assignment for the benefit of its creditors; or (ii) there shall be commenced against the Agency any case, proceeding or other action of a nature referred to in clause (i) of this paragraph (h) which (x) results in an order for such relief or in the appointment of a receiver or similar official or (y) remains undismissed, undischarged or unbonded for a period of 60 days; or (iii) there shall be commenced against the Agency, any case, proceeding or other action seeking issuance of a warrant of attachment, execution, distraint or similar process against all or any substantial part of its assets, which results in the entry of an order for any such relief which shall not have been vacated, discharged, or stayed or bonded pending appeal within 60 days from the entry thereof; or (iv) the Agency shall take any action in furtherance of, or indicating its consent to, approval of, or acquiescence in, any of the acts set forth in clause (i), (ii) or (iii) of this paragraph (h); (v) the Agency shall admit in writing its inability to pay its debts generally as they become due, or shall become insolvent within the meaning of Section 101(32) of the United Stated Bankruptcy Code; or (vi) a financial control board, or its equivalent, shall be imposed upon the Agency by a Governmental Authority and such financial control board has the ability to exercise authority or control over the Trust Estate or over the Subordinated Indebtedness Fund;

(i) (i) any two of Fitch, Moody's or S&P (as such terms are defined in the Credit Agreement) suspends, withdraws or downgrades the long-term unenhanced rating of any Senior Lien Debt (as defined in the Credit Agreement), or Debt (as defined in the Credit Agreement) payable on a parity basis with the Senior Lien Debt below "A-" (or its equivalent), "A3" (or its equivalent) or "A-" (or its equivalent), respectively; provided that if only two of Fitch, Moody's or S&P provide a long-term unenhanced rating on any Senior Lien Debt or on Debt payable on a parity basis with the Senior Lien Debt, it shall be an Event of Default if any Rating Agency suspends, withdraws or downgrades the long-term unenhanced rating of any Senior Lien Debt, or Debt payable on a parity basis with the Senior Lien Debt below "A-" (or its equivalent), "A3" (or its equivalent) or "A-" (or its equivalent); or (ii) the long term unenhanced rating assigned by each of Fitch, Moody's and S&P to any Debt secured by a pledge of and security interest in the

Trust Estate, the CP Note Payment Account or the Subordinated Indebtedness Fund that is senior to or on a parity with the Series B Commercial Paper Notes shall be withdrawn or suspended (other than any such withdrawal or suspension that the applicable Rating Agency (as defined in the Credit Agreement) stipulates is for non-credit related reasons) or reduced below Investment Grade (as defined in the Credit Agreement); or

(j) (i) the Agency shall impose a debt moratorium, debt restructuring, debt adjustment or comparable extraordinary restriction on the repayment when due and payable of the principal of or interest on the Series B Notes, the Bank Note or the Loans or any Senior and Parity Lien Debt or (ii) any Governmental Authority having appropriate jurisdiction over the Agency shall make a finding or ruling or shall enact or adopt legislation or issue an executive order or enter a judgment or decree which results in a debt moratorium, debt restructuring, debt adjustment or comparable extraordinary restriction on the repayment when due and payable of the principal of or interest on the Series B Notes, the Bank Note, the Loans or on all indebtedness for borrowed money of the Agency;

(k) any funds or accounts or investments on deposit in, or otherwise to the credit of, any of the funds or accounts established pursuant to the Issuing and Paying Agency Agreement, the Resolution, the Subordinated Resolution or the other Program Documents, that have been pledged to or a lien granted thereon to secure the Commercial Paper Notes or the Bank Note, shall become subject to any writ, judgment, warrant or attachment, execution or similar process which shall not have been vacated, discharged, or stayed or bonded pending appeal within 30 calendar days from the entry thereof;

(l) (i) any "event of default" shall have occurred and be continuing under any Program Document beyond the expiration of any applicable grace period or (ii) any "event of default" under any Bank Agreement (as defined in the Credit Agreement) with respect to any Debt shall have occurred and be continuing beyond the expiration of any applicable grace period; or

(m) the Agency shall cease to exist, dissolve or terminate.

Remedies

Upon the occurrence of any Event of Default, other than an Event of Default specified in paragraph (h) under the heading "Events of Default" above, the Bank shall declare the Bank Note, all accrued interest thereon, and all other amounts payable under the Credit Agreement to be forthwith due and payable, whereupon the Bank Note and such interest and all such amounts shall become and be forthwith due and payable without presentment, demand, protest or further notice of any kind, all of which are expressly waived by the Agency. If any Event of Default specified in paragraph (h) under the heading "Events of Default" above shall occur, without any notice to the Agency or any other act by the Bank, the Bank Note, together with accrued interest thereon, and all other amounts payable under the Credit Agreement, shall become forthwith due and payable, without presentment, demand, protest, or other notice of any kind, all of which are waived by the Agency.

Upon the occurrence of any Event of Default described in paragraphs (a)(1)(i), (a)(1)(ii), (d)(i), (e)(i), (g), (h), (i)(ii), (j) or (m) under the heading "Events of Default" above (each a

"Special Event of Default"), the Commitment shall automatically and immediately terminate with respect to all Series B Notes and the Bank shall have no obligation to make any Loan or to fund any outstanding Series B Note.

Upon the occurrence of an Event of Default that is not a Special Event of Default, the Bank shall, by notice to the Agency, terminate the Commitment, if any (except as provided below), deliver a No-Issuance Notice (as defined in the Credit Agreement) to the Issuing and Paying Agent directing the Issuing and Paying Agent to cease issuing all Series B Notes, whereupon no additional Series B Notes shall be issued, the Available Commitment (as defined in the Credit Agreement) shall immediately be reduced to the then outstanding principal amount of Series B Notes, and the Available Commitment shall be further reduced in a similar manner as and when such Series B Notes mature; provided that the Commitment shall not terminate, and the right of the Bank to accelerate the maturity of the Bank Note shall not affect the obligation of the Bank to make Loans in an aggregate principal amount equal to the Commitment to the extent necessary for the Agency to make required payments of principal on the Series B Notes issued and sold prior to the date upon which the No-Issuance Notice is received by the Issuing and Paying Agent; provided further that if any Loans are made that would not have been made but for the application of the immediately preceding provision, such Loans shall be immediately due and payable on the date such Loans are made.

Upon the occurrence of an Event of Default under clause (ii) of paragraph (e) under the heading "Events of Default" above, the obligation of the Bank to make Loans under the Credit Agreement shall be suspended from the time of the occurrence of such Event of Default until a final, non-appealable judgment of a court having jurisdiction in the premises shall be entered declaring that all contested provisions of the Credit Agreement, the Series B Notes, the Bank Note, the Issuing and Paying Agency Agreement, the Resolution or the Subordinated Resolution relating to the payment of principal or interest on the Series B Notes, the Bank Note or any Loans or the validity or enforceability of the pledge and security interest in amounts in the Subordinated Indebtedness Fund are upheld in their entirety. In the event such judgment is entered declaring that all material contested provisions of the Credit Agreement, the Series B Notes, the Bank Note, the Issuing and Paying Agency Agreement, the Resolution or the Subordinated Resolution relating to the payment of principal or interest on the Series B Notes, the Bank Note or any Loans or the validity or enforceability of the pledge of and security interest in amounts in the Subordinated Indebtedness Fund are upheld in their entirety, the obligation of the Bank to make Loans under the Credit Agreement shall be automatically reinstated and the terms of the Credit Agreement will continue in full force and effect (unless the Credit Agreement shall have otherwise expired or terminated in accordance with the terms of the Credit Agreement or there has occurred a Special Event of Default) as if there had been no suspension. In the event any provision of the Credit Agreement, the Series B Notes, the Bank Note, the Issuing and Paying Agency Agreement, the Resolution or the Subordinated Resolution relating to the payment of principal or interest on the Series B Notes, the Bank Note or any Loans or the validity or enforceability of the pledge of and security interest in amounts in the Subordinated Indebtedness Fund is declared to be null and void or unenforceable, or it is determined that the Agency has no liability or obligation under the Credit Agreement, the Series B Notes, the Bank Note, the Issuing and Paying Agency Agreement, the Resolution or the Subordinated Resolution, then the obligations of the Bank under the Credit Agreement will terminate as set forth above. Notwithstanding the foregoing, if, upon the date which is the earlier of the Commitment Termination Date or three years after the effective date of such suspension of the obligation of the Bank pursuant to this paragraph, litigation is still pending and a judgment regarding the validity and enforceability the Credit Agreement, the Series B Notes, the Bank Note, the Issuing and Paying Agency Agreement, the Resolution or the Subordinated Resolution to the payment of principal or interest on the Series B Notes, the Bank Note or any Loans or the validity or enforceability of the pledge of and security interest in amounts in the Subordinated Indebtedness Fund as is the subject of such Event of Default has not been obtained, then the Commitment and the obligation of the Bank to make Loans under the Credit Agreement shall at such time terminate without notice or demand.

Upon the occurrence of a Default (as defined in the Credit Agreement) under clause (ii) or (iii) of paragraph (h) under the heading "Events of Default" above, the obligation of the Bank to make Loans under the Credit Agreement shall be suspended until the proceeding referred to in clause (ii) or (iii) of paragraph (h) under the heading "Events of Default" above is terminated prior to the court entering an order granting the relief sought in such proceeding. In the event such proceeding is terminated, the obligation of the Bank to make Loans under the Credit Agreement shall be reinstated and the terms of the Credit Agreement will continue in full force and effect (unless the obligation of the Bank to make Loans under the Credit Agreement shall have otherwise expired or terminated in accordance with the terms of the Credit Agreement or there has occurred a Special Event of Default) as if there had been no such suspension.

Failure to take action in regard to one or more Events of Default shall not constitute a waiver of, or the right to take action in the future in regard to, such or subsequent Events of Default.

Bank Note

The Agency has issued its Bank Note, to evidence any loans made by the Bank under the Credit Agreement. The Bank Note is issued under the Subordinated Resolution on a parity with the Series B Notes.

Substitution of Liquidity Support Arrangement

Under the Subordinated Resolution, the Agency may not substitute another liquidity support arrangement for the Credit Agreement unless either: (i) the Agency has received written confirmation from each rating agency then rating the Series B Notes to the effect that such assignment will not, by itself, result in a reduction, suspension or withdrawal of such rating agency's ratings of the Series B Notes from those which then prevail; or (ii) the substitution is not, by its terms, effective as to Series B Notes issued prior to the date on which the substitution occurs.

The Agency has agreed to provide notice to the holders of affected Series B Notes of any change in the provider of liquidity support for the Series B Notes.

ADDITIONAL INFORMATION

During the period of the offering of the Series B Notes, a copy of the most recent official statement for Power Supply System Revenue Bonds (together with appendices thereto and documents incorporated therein by reference), copies of the Resolution and the Subordinated Indebtedness Resolution, copies of the Agency's most recent financial report, and other documents referred to herein may be obtained from the Agency by contacting the Director of Finance and Accounting & CFO at Southern Minnesota Municipal Power Agency, 500 First Avenue, S.W., Rochester, MN 55902-3303, (507) 285-0478.

Additionally, certain information with respect to the Agency is available from the Municipal Securities Rulemaking Board (the "MSRB") through the MSRB's Electronic Municipal Market Access ("EMMA") website, currently located at http://emma.msrb.org. In the event that in the future such information is not available from the MSRB or any other entity designated or authorized by the Securities Exchange Commission to receive reports pursuant to Rule 15c2-12 of the Securities and Exchange Act of 1934, as amended, the Agency would provide periodic updates to this Commercial Paper Offering Memorandum, as appropriate.

RATINGS

Power Supply System Notes, Series B

P-1 (Moody's Investors Service, Inc.)

A-1 (Standard & Poor's Ratings Services, a Standard & Poor's Financial Services LLC business)

January 11, 2016

If there are any questions concerning this memorandum, contact
Southern Minnesota
Municipal Power Agency
Director of Finance and Accounting
and CFO
(507) 285-0478

LEGAL OPINION, AND FINANCIAL STATEMENTS AND INFORMATION REGARDING THE BANK

The following is the form of the legal opinion of Orrick, Herrington & Sutcliffe LLP, rendered on November 19, 2013, with respect to the Series B Notes, followed by the audited financials of KPMG LLP and certain information with respect to the Bank.

ORRICK

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APPENDIX A

November 19, 2013

Board of Directors
Southern Minnesota Municipal
Power Agency
500 First Avenue, S.W.
Rochester, Minnesota 55902

Southern Minnesota Municipal Power Agency
Power Supply System Commercial Paper Notes, Series B

Gentlemen:

We have acted as bond counsel to Southern Minnesota Municipal Power Agency (the "Agency"), a municipal corporation and political subdivision of the State of Minnesota, in connection with the issuance from time to time by the Agency of its Power Supply System Commercial Paper Notes, Series B, in an aggregate principal amount outstanding at any time not to exceed $68,000,000 (the "Commercial Paper Notes"), issued pursuant to the Constitution and laws of the State of Minnesota, including, in particular, Sections 453.51 to 453.62, inclusive, of Minnesota Statutes, as amended (the "Act"), and under and pursuant to a resolution of the Agency adopted on May 10, 1995 entitled "Power Supply System Subordinated Indebtedness Resolution No. 2," as heretofore supplemented and amended (the "Subordinated Indebtedness Resolution"). The Subordinated Indebtedness Resolution is supplemental to a resolution of the Agency adopted on May 11, 1983 entitled "Power Supply System Revenue Bond Resolution," as supplemented and amended to the date hereof (said Power Supply System Revenue Bond Resolution, as so supplemented and amended, is referred to herein as the "Bond Resolution"). Capitalized terms not otherwise defined herein shall have the same meanings given to such terms in the Subordinated Indebtedness Resolution or, if not defined therein, in the Bond Resolution.

The Commercial Paper Notes may be issued only for the purposes of (i) financing or refinancing Costs of Acquisition and Construction of the System; (ii) providing for the retirement of certain of the Agency's Outstanding Bonds; (iii) paying the principal of, and interest on, the Commercial Paper Notes; and (iv) paying amounts owed under the Bank Notes. The Commercial Paper Notes, when issued and delivered in accordance with the Subordinated Indebtedness Resolution, will constitute "Subordinated Indebtedness" for purposes of the Bond Resolution.

Subject to any limitations contained in the Credit Agreement, the Agency reserves the right to issue additional Subordinated Indebtedness on the terms and conditions and for the purposes stated in the Bond Resolution. Under the provisions of the Subordinated Indebtedness

Resolution and the Bond Resolution, any such Subordinated Indebtedness may rank equally as to security and payment with the Commercial Paper Notes.

In such connection, we have reviewed a certified copy of the Bond Resolution; a certified copy of the Subordinated Indebtedness Resolution; a certified copy of the Issuing and Paying Agency Agreement, dated as of May 10, 1995 (the "Issuing and Paying Agency Agreement"), between the Agency and U.S. Bank National Association, formerly known as First Trust National Association (the "Agent"); a Tax Certificate, dated the date hereof (the "Tax Certificate"); an opinion of Dorsey & Whitney, general counsel to the Agency, dated March 31, 1998; certificates of the Agency and others; and such other documents, opinions and matters to the extent we deemed necessary to render the opinions set forth herein.

The opinions expressed herein are based upon an analysis of existing laws, regulations, rulings and court decisions, and cover certain matters not directly addressed by such authorities. Such opinions may be affected by actions taken or omitted or events occurring after the date hereof and before or after Commercial Paper Notes are issued. We have not undertaken to determine, or to inform any person, whether any such actions are taken or omitted or events do occur or any other matters come to our attention after the date hereof. Accordingly, this letter speaks only as of its date and is not intended to, and may not, be relied upon or otherwise used in connection with any such actions, events or matters. We disclaim any obligation to update this letter. We have assumed the genuineness of all documents and signatures presented to us (whether as originals or as copies) and the due and legal execution and delivery thereof by, and validity against, any parties other than the Agency. We have assumed, without undertaking to verify, the accuracy (as of the date hereof and as of the dates of issuance from time to time of the Commercial Paper Notes) of the factual matters represented, warranted or certified in the documents, and of the legal conclusions contained in the opinions, referred to in the fourth paragraph hereof (except that we have not relied on any such legal conclusions that are to the same effect as the opinions set forth herein). Furthermore, we have assumed compliance with all covenants and agreements contained in the Subordinated Indebtedness Resolution, the Tax Certificate and the Issuing and Paying Agency Agreement, including (without limitation) covenants and agreements compliance with which is necessary to assure that future actions, omissions or events will not cause interest on the Commercial Paper Notes to be included in gross income for federal income tax purposes, possibly retroactive to November 19, 2013. We call attention to the fact that the rights and obligations under the Commercial Paper Notes, the Subordinated Indebtedness Resolution, the Tax Certificate and the Issuing and Paying Agency Agreement and their enforceability may be subject to bankruptcy, insolvency, reorganization, arrangement, fraudulent conveyance, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, to the exercise of judicial discretion in appropriate cases and to the limitations on legal remedies against municipal corporations and political subdivisions of the State of Minnesota. We express no opinion with respect to any indemnification, contribution, liquidated damages, penalty (including any remedy deemed to constitute a penalty), arbitration, choice of law, choice of forum, choice of venue, waiver or severability provisions contained in the foregoing documents. Our services did not include financial or other non-legal advice. Finally, we undertake no responsibility for the accuracy, completeness or fairness of any offering material relating to the Commercial Paper Notes and express no opinion with respect thereto.

Based on and subject to the foregoing, and in reliance thereon, as of the date hereof, we are of the following opinions:

1. The Agency is duly created and validly existing under the provisions of the Act, and is authorized (i) to offer, issue, sell and deliver the Commercial Paper Notes for the purposes specified in the Subordinated Indebtedness Resolution and (ii) to perform its obligations under the Commercial Paper Notes and the Subordinated Indebtedness Resolution.

2. The Agency has full power and authority to take all action required or permitted to be taken by it under the Commercial Paper Notes and the Subordinated Indebtedness Resolution, and to perform and observe the covenants and agreements on its part contained in the Commercial Paper Notes and the Subordinated Indebtedness Resolution.

3. The Agency is duly authorized and entitled to issue the Commercial Paper Notes, and the Commercial Paper Notes, when duly executed by the President, the Vice President, the Treasurer or the Executive Director and CEO of the Agency, sealed by the seal of the Agency and attested by the Treasurer, the Secretary or any other authorized officer of the Agency, and authenticated and delivered by the Agent against payment therefor, all as provided in the Subordinated Indebtedness Resolution and the Issuing and Paying Agency Agreement, will constitute legal, valid and binding obligations of the Agency in accordance with their terms, payable solely from amounts in the CP Note Payment Account and amounts in the Subordinated Indebtedness Fund. The Agency has validly pledged, and a security interest has been granted in, the CP Note Payment Account and the Subordinated Indebtedness Fund for the benefit of the Holders of Commercial Paper Notes; provided, however, that in the case of the Subordinated Indebtedness Fund, (i) such pledge and security interest shall be on a parity with the pledge thereof and security interest therein created by the Subordinated Indebtedness Resolution as security for the Bank Notes issued in connection with borrowings under the Credit Agreement; and (ii) such pledge and security interest shall be subordinate in all respects to the pledge and assignment of the Trust Estate created by the Bond Resolution as security for Bonds. The Commercial Paper Notes are direct and special obligations of the Agency and neither the State of Minnesota nor any political subdivision (other than the Agency) nor any city which is a member of the Agency shall be obligated to pay the principal thereof or interest thereon and neither the faith and credit nor the taxing power of the State of Minnesota or any political subdivision

thereof or of any such city is pledged to the payment of the principal of, or interest on, the Commercial Paper Notes. No Holder or receiver or trustee in connection with the payment of the Commercial Paper Notes shall have any right to compel the State of Minnesota, any political subdivision thereof or any city which is a member of the Agency to exercise its appropriation or taxing powers.

4. The agreements and covenants of the Agency contained in the Bond Resolution, including those contained in the Subordinated Indebtedness Resolution, are valid and binding agreements and covenants of the Agency, enforceable against the Agency in accordance with their respective terms.

5. Interest on the Commercial Paper Notes, when issued in accordance with the Subordinated Indebtedness Resolution, the Issuing and Paying Agency Agreement and the Tax Certificate, will be excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986. The amount treated as interest on the Commercial Paper Notes and excluded from gross income will depend on the taxpayer's election under Internal Revenue Service Notice 94–84. Interest on the Commercial Paper Notes is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although we observe that such interest is included in adjusted current earnings when calculating in corporate alternative minimum taxable income.

6. When issued in accordance with the Subordinated Indebtedness Resolution, the Issuing and Paying Agency Agreement and the Tax Certificate, interest on the Commercial Paper Notes will be excluded from State of Minnesota gross income with respect to individuals.

Except as stated in paragraphs 5 and 6, we express no opinion regarding other tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the Commercial Paper Notes.

This opinion letter, rather than our opinion letter dated December 6, 2006, relating to the validity of the Commercial Paper Notes and certain other matters, shall apply to all Commercial Paper Notes issued after the date hereof.

Faithfully yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

KPMG

SOUTHERN MINNESOTA MUNICIPAL POWER AGENCY

Financial Statements

December 31, 2014 and 2013

(With Independent Auditors' Report Thereon)

SOUTHERN MINNESOTA MUNICIPAL POWER AGENCY

Table of Contents

KPMG LLP
4200 Wells Fargo Center
90 South Seventh Street
Minneapolis, MN 55402

Independent Auditors' Report

The Board of Directors
Southern Minnesota Municipal Power Agency:

Report on Financial Statements

We have audited the accompanying financial statements of Southern Minnesota Municipal Power Agency (the Agency), which comprise the statements of net position as of December 31, 2014 and 2013, and the related statements of revenues, expenses, and changes in net position and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with U.S. generally accepted accounting principles; 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 audit 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 entity'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 entity'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 Southern Minnesota Municipal Power Agency as of December 31, 2014 and 2013, and the changes in its financial position and its cash flows for the years then ended, in accordance with U.S. generally accepted accounting principles.

Other Matter

U.S. generally accepted accounting principles require that the management's discussion and analysis on pages 3 through 10 be presented to supplement the basic financial statements. Such information, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic financial statements, and other knowledge we obtained during our audit of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

KPMG LLP

Minneapolis, Minnesota
March 5, 2015

Financial Statements Overview

This discussion and analysis of Southern Minnesota Municipal Power Agency's (the Agency) financial performance provides an overview of the Agency's activities for the fiscal years ended December 31, 2014 and 2013. The information presented should be read in conjunction with the basic financial statements and the accompanying notes to the financial statements.

The basic financial statements are prepared on the accrual basis of accounting in accordance with U.S. generally accepted accounting principles. The Agency complies with all applicable pronouncements of the Governmental Accounting Standards Board (GASB). This includes GASB Statement 62, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements*. GASB 62 incorporates into the GASB's authoritative literature certain accounting and financial reporting guidance that is included in FASB and AICPA pronouncements issued on or before November 30, 1989, which does not conflict with GASB pronouncements. The Agency also follows the guidance of GASB Statement 42, *Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries*. The Agency follows the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC).

The Agency's basic financial statements include the statement of net position, the statement of revenues, expenses, and changes in net position, and the statement of cash flows. The statement of net position provides information about the nature and amount of assets and obligations (liabilities) of the Agency as of the end of the year. The statement of revenues, expenses, and changes in net position reports revenues and expenses for the current year. The statement of cash flows reports cash receipts, cash payments, and net changes in cash resulting from operating activities, noncapital financing activities, capital and related financing activities, and investing activities.

Summary of Significant Capital and Financing Activities

The Agency has a number of capital projects with an existing and/or ongoing effect on the financial statements. A brief summary of each is as follows:

Sherco 3

In November 2011, during post overhaul testing of Sherco 3, a failure occurred with the unit's steam turbine and generator. As a consequence of the Sherco 3 turbine and generator failure, Sherco 3 was idled while the unit underwent restoration. Sherco 3 was resynchronized to the electric grid in the fall of 2013. Insurance proceeds received by the Agency as of the end of 2014 were approximately $82.0 million, which is a substantial portion of the Agency's expected total cost. As of December 31, 2014, an additional $11.2 million in proceeds were expected from the insurers. Final payment is expected in 2015.

Fairmont Energy Station

The 25MW Fairmont Energy Station began operations in January 2014. Three of the four high efficiency natural gas fired spark-ignited engines were accepted from the vendor, Caterpillar, and entered into commercial operation on September 8, 2014. The fourth unit went into commercial operation on December 13, 2014. Fairmont is a member municipality.

CapX 2020

Following execution of participation agreements in December 2012, construction of the CapX 2020 Hampton to La Crosse transmission line commenced. Upon completion, it is anticipated the Agency will own 13% of the 345 kV and 161 kV facilities in the project. CapX 2020 consists of twelve transmission owning utilities in Minnesota and Wisconsin. The Hampton to La Crosse line is the last of several high voltage transmission projects to be constructed. Hampton, Minnesota is located south of the Minneapolis/St. Paul area. The line runs south from a new substation near Hampton to Rochester, MN, and east into Wisconsin to a substation located north of La Crosse, WI. The CapX 2020 projects will significantly increase transmission transfer capability and regional electrical reliability. Capital expenditures incurred by the Agency in 2014 and 2013 pertaining to this project were approximately $12.3 million and $21.1 million, respectively. Construction work in progress includes $36.9 million and $24.6 million pertaining to this project as of December 31, 2014 and 2013, respectively.

Other Capital Projects

- **Proposed Owatonna Energy Station**

  The Agency finalized site selection and the planning process for a high efficiency gas fired energy station near Owatonna, Minnesota, an Agency member community. The approximately 35 MW unit will be similar to the Fairmont Energy Station if constructed. The Agency plans to seek member and board approval for the project during 2015.

- **Wisconsin Transmission Project**

  During 2014, the Agency formed SMMPA Wisconsin LLC (the LLC) in order to participate as an investor and passive owner in a 345 kV transmission project in Wisconsin. The Agency subsequently filed before the Public Service Commission of Wisconsin (the Commission) to have the LLC declared a public utility so that it may own utility assets in Wisconsin. The Commission approved the Agency's request on February 12, 2015. As currently structured, the Agency would own 6.5% of the project, which is designated as a multi-value project by the Midwest Independent System Operator (MISO). The Agency's investment in the project would be approximately $36.0 million. As of December 31, 2014 no capital activity has occurred.

Agency Financings

The Agency did not issue any new debt or refund existing debt during either 2014 or 2013. In 2014, the Agency renewed its existing commercial paper liquidity facility and credit agreement through November 2017.

Financial Highlights

Condensed Statements of Net Position
($ millions)

		2014	2013	2012	2014 to 2013 change	2013 to 2012 change
Current assets	$	216.1	230.7	267.8	(14.6)	(37.1)
Noncurrent assets:						
Capital assets, net		477.7	471.4	403.3	6.3	68.1
Noncurrent investments		72.0	71.7	89.7	0.3	(18.0)
Deferred outflows:						
Future recoverable costs – noncurrent		220.3	232.1	240.7	(11.8)	(8.6)
Decrease in fair value of derivative instruments – noncurrent		0.7	0.9	0.8	(0.2)	0.1
Total assets and deferred outflows	$	986.8	1,006.8	1,002.3	(20.0)	4.5
Current liabilities	$	137.5	120.6	93.4	16.9	27.2
Long-term liabilities:						
Long-term debt, net		592.4	618.7	642.2	(26.3)	(23.5)
Derivative instruments – swap liability		0.7	0.9	0.8	(0.2)	0.1
Other long-term obligations		—	17.8	23.3	(17.8)	(5.5)
Deferred inflows:						
Deferred credits rate stabilization		93.0	92.5	100.6	0.5	(8.1)
Deferred gain on involuntary conversion of plant assets		64.8	67.4	66.6	(2.6)	0.8
Total liabilities and deferred inflows		888.4	917.9	926.9	(29.5)	(9.0)
Net position:						
Net investment in capital assets		95.1	43.8	(9.9)	51.3	53.7
Restricted		66.8	58.8	55.8	8.0	3.0
Unrestricted		(63.5)	(13.7)	29.5	(49.8)	(43.2)
Total net position		98.4	88.9	75.4	9.5	13.5
Total liabilities, deferred inflows, and net position	$	986.8	1,006.8	1,002.3	(20.0)	4.5

Condensed statements of net position highlights are as follows:

- The assets of the Agency exceeded its liabilities at the close of 2014 by approximately $98.4 million, at the close of 2013 by approximately $88.9 million, and at the close of 2012 by approximately $75.4 million (net position).
- Current assets decreased by approximately $14.6 million in 2014 and by approximately $37.1 million in 2013. Current assets include deposits and investments held in revenue and operating funds of approximately $27.6 million at December 31, 2014 to be used for operating, maintenance, and working capital needs of the Agency, and increased by approximately $3.6 million in 2014. Current assets at December 31, 2014 also

include deposit and investments held in restricted funds of approximately $65.5 million in accordance with the bond resolution for debt service requirements. In 2013, current assets include deposits and investments held in revenue and operating funds of approximately $24.0 million to be used for operating, maintenance, and working capital needs of the Agency and also include deposits and investments held in restricted funds of approximately $57.7 million in accordance with the senior bond resolution for debt service requirements.

- The insurance claim receivable, which is also part of current assets, decreased by approximately $2.1 million during 2014 and represents the Agency's estimate of its proportionate share of the insurance claim receivable. During 2013, the insurance claim receivable decreased by approximately $35.1 million to $13.3 million at December 31, 2013. The decreases are a result of receipt of insurance proceeds for repairs that were made to Sherco 3's turbine and generator.
- Capital assets, net, increased by approximately $6.3 million during 2014. Capital assets, net, include the Agency's 41% undivided ownership interest in the Sherburne County Generating Unit No. 3 (Sherco 3) plant with a historical cost of approximately $552.0 million as of December 31, 2014. The Agency also has approximately $209.3 million on a historical cost basis of substation facilities, transmission lines, land, wind turbines, buildings, upgrades to members' generating units under contract, and general office equipment recorded as of the end of 2014. In addition, the Agency capitalizes improvements made to member owned generation under Agency contract. Capital assets, net, increased by approximately $68.1 million during 2013. The Agency's 41% undivided ownership interest in the Sherco 3 plant was approximately $531.8 million as of December 31, 2013. Capital assets, net, also included approximately $181.4 million on a historical cost basis of substation facilities, transmission lines, land, wind turbines, buildings, upgrades to members' generating units under contract, and general office equipment at the end of 2013.

  For 2014, the increase in capital assets, net, is the result of an increase in electric plant and equipment, net, of approximately $33.1 million and a net decrease in construction in progress of approximately $26.7 million. The increase in electric plant and equipment, net, is a result of an increase of approximately $20.2 million for Sherco 3 repairs and capital improvements made, an increase of approximately $31.4 million for the construction of Fairmont Energy Station, a decrease of approximately $3.8 million in transmission assets, and an increase of approximately $0.3 million in other capital improvements, offset by an increase in accumulated depreciation of approximately $15.0 million. For 2013, the increase in capital assets, net, is the result of an increase in electric plant and equipment, net, of approximately $79.6 million and a net decrease in construction in progress of approximately $11.5 million. The increase in electric plant and equipment, net, is a result of transfers from construction in progress as well as an increase of approximately $82.5 million for Sherco 3 repairs and capital improvements made, an increase of approximately $6.5 million in transmission assets, an increase of approximately $2.4 million in other capital improvements, offset by an increase in accumulated depreciation of approximately $11.8 million.

- Noncurrent investments include investments held in restricted funds in accordance with the bond resolution for debt service and capital construction projects, increased by approximately $0.3 million in 2014 and decreased by approximately $18.0 million in 2013 due to reimbursement of capital construction projects.
- Deferred outflows, future recoverable costs decreased by approximately $11.8 million in 2014 and $8.6 million in 2013. Deferred outflows, future recoverable costs are costs in excess of the amounts currently billable to the members that are to be recovered from future revenues by setting rates sufficient to provide funds for the related debt service payments.

(Continued)

- Deferred outflows, decrease in fair value of derivative instruments decreased, by approximately $0.2 million in 2014 and increased by approximately $0.1 million in 2013. Deferred outflows of resources result from hedging of cash flows associated with the Agency's variable interest rate debt through the use of pay-fixed, receive-variable interest rate swaps. This amount offsets the fair value of the Agency's interest rate swaps at December 31.

- Current liabilities increased by approximately $16.9 million in 2014. The current portion of long-term debt of approximately $51.9 million and $48.5 million at December 31, 2014 and 2013, respectively, and commercial paper notes payable are included in current liabilities. Attributable to the total increase in total current liabilities was a $3.7 million decrease in accounts payable – power production, an $18.4 million increase in accrued liabilities and other payables, an increase of approximately $3.4 million in current maturities of long-term debt, offset by a decrease of approximately $1.2 million in accrued interest payable. The increase in accrued liabilities of $18.4 million is primarily due to the reclassification of a $12.6 million liability for the Agency's obligation under a shared transmission system agreement with Dairyland Power Cooperative from other long-term liabilities to current liabilities. Under terms of a memorandum of understanding with Dairyland, it is anticipated that the liability will be settled by the end of 2015. The obligation decreased by approximately $5.2 million during 2014. Current liabilities increased by approximately $27.2 million in 2013. The current portion of long-term debt of approximately $48.5 million and $45.0 million of commercial paper notes payable are included in current liabilities. Attributable to the net increase in total current liabilities was a $2.9 million decrease in accounts payable – power production, a $3.0 million increase in accrued liabilities and other payables, an increase of $24.0 million in commercial paper notes payable, an increase of approximately $4.2 million in current maturities of long-term debt, and a decrease of approximately $1.1 million in accrued interest payable.

- The carrying value of long-term debt at the end of 2014 was approximately $592.4 million. Scheduled principal payments of approximately $48.5 million were made in 2014. The carrying value of long-term debt at the end of 2013 was approximately $618.7 million. Scheduled principal payments of approximately $44.3 million were made in 2013. The carrying value of the long-term debt was also impacted by the effect of bond discount/premium amortization.

- Deferred inflows, deferred credits rate stabilization, current and long-term, increased by approximately $0.5 million. The increase was a result of net contributions to the account during 2014. During 2013, deferred inflows, deferred credits rate stabilization, current and long-term decreased by approximately $8.1 million, resulting in net distributions from the fund.

(Continued)

- Deferred inflows, gain on involuntary conversion of plan assets, current and long-term decreased by approximately $2.6 million in 2014 and increased by approximately $0.8 million in 2013. The deferred gain, which represents the difference between the amount of the estimated insurance recovery and the carrying value of the capital assets impaired, will be amortized by the Agency into income over the remaining life of Sherco 3 at the time of the 2011 incident.

Condensed Statements of Revenues, Expenses, and Changes in Net Position
($ millions)

	2014	2013	2012	2014 to 2013 change	2013 to 2012 change
Operating revenues, power sales	$ 242.1	253.0	241.3	(10.9)	11.7
Other revenues	2.5	2.3	2.9	0.2	(0.6)
Total revenues	244.6	255.3	244.2	(10.7)	11.1
Operating expenses	190.5	195.0	188.5	(4.5)	6.5
Other expenses	44.6	46.8	47.3	(2.2)	(0.5)
Total expenses	235.1	241.8	235.8	(6.7)	6.0
Change in net position	9.5	13.5	8.4	(4.0)	5.1
Beginning net position	88.9	75.4	67.0	13.5	8.4
Ending net position	$ 98.4	88.9	75.4	9.5	13.5

Condensed statements of revenues, expenses, and changes in net position highlights are as follows:

- Operating revenues, power sales, decreased by approximately $10.9 million between 2014 and 2013 and increased by approximately $11.7 million between 2013 and 2012. Operating revenues, power sales, consist principally of member power sales revenue, power sales to nonmembers, other transmission revenue, and contributions to, or distributions from, the rate stabilization account. Sales to nonmembers include the Agency's participation in the MISO Day 2 market.

  In 2014, before the effects of contributions made to the rate stabilization account, operating revenues, power sales, decreased by approximately $2.2 million, primarily due to decreases in the member sales by $1.8 million and transmission service agreement revenues by $2.2 million, offset by increases in MISO energy market sales of $1.8 million. In 2013, before the effects of distributions made from the rate stabilization account, operating revenues, power sales, increased by approximately $3.4 million, primarily due to an increase in MISO energy market sales by approximately $1.4 million, by an increase of approximately $1.1 million in transmission revenue, and by an increase in power sales to members of approximately $0.9 million. There was a net contribution of approximately $0.5 million to the rate stabilization account in 2014 compared with a net distribution of $8.1 million in 2013 and net contribution of $0.2 million in 2012. Contributions to the rate stabilization account decrease the amount of operating revenues, power sales, whereas distributions from the rate stabilization account increase the amount of operating revenues, power sales as funds are added to, or subtracted from, the rate stabilization account, which is included in deferred inflows.

- Other revenues increased by approximately $0.2 million between 2014 and 2013 and decreased by approximately $0.6 million between 2013 and 2012. Other revenues include the Build America Bonds (BABs) interest subsidy and rental income.
- Operating expenses decreased by approximately $4.5 million between 2014 and 2013 and increased by approximately $6.5 million between 2013 and 2012. Operating expenses consist of production fuel, power production, other operating expenses, depreciation and amortization, and expenses to be recovered in future periods. The decrease observed in 2014, compared with 2013, was the net result of an increase in production fuel expense of approximately $39.3 million with Sherco 3 back on line, offset by a decrease in power production expenses of approximately $52.6 million reflecting reduced energy market purchases with Sherco 3 back on line, an increase in other operating expenses of approximately $6.7 million (consisting mainly of an increase of approximately $1.9 million in transmission expenses, an increase of approximately $3.0 million in Sherco 3 operating and maintenance expenses, an increase in administrative and member services of approximately $0.8 million and an increase of approximately $0.6 million of demand side management expenses) and a combined increase of approximately $2.2 million in depreciation and expenses to be recovered in future periods. The increase observed in 2013 compared with 2012 was the net result of an increase in production fuel expense of approximately $6.2 million, a decrease in power production expenses of approximately $6.5 million, an increase in other operating expenses of approximately $5.6 million (due to a decrease of approximately $0.6 million in transmission expenses, an increase of approximately $5.5 million in Sherco 3 operating and maintenance expenses, an increase of approximately $0.5 million of other Agency owned generation, a decrease in administrative and member services of approximately $0.4 million and an increase of approximately $0.6 million of in-lieu of property taxes) and a combined increase of approximately $1.2 million in depreciation and expenses to be recovered in future periods.

Debt Administration

As of December 31, 2014 and 2013, the carrying value of the Agency's total long-term debt outstanding, including current maturities, was approximately $644.4 million and $667.2 million, respectively. The decrease in 2014 is the net result of the scheduled principal payments of approximately $48.5 million made in January 2014, and the effect of bond discount/premium amortization of approximately $25.6 million. Similarly, in 2013 the decrease is the net result of the scheduled principal payments of approximately $44.3 million made in January 2013 and the net effect of bond discount/premium amortization of approximately $25.0 million. The total short-term commercial paper notes outstanding as of December 31, 2014 and 2013 were $45.0 million and $21.0 million in 2012.

During 2014, the Agency added Fitch Ratings as a third rating agency for the Agency's bond issuances. Fitch Ratings released a public rating of A+/Stable on the Agency's 2010 Series A and B bonds in November 2014. Standard and Poor's and Moody's Investor Services affirmed the Agency's A+/Stable and A1/Stable long term ratings, as well as the Agency's A-1 and P-1 short term ratings, respectively.

Contact Information

This financial report is designed to provide a general overview of the Agency's finances. Questions or requests for additional information should be addressed to the Manager of Accounting, 500 First Avenue Southwest, Rochester, Minnesota 55902.

SOUTHERN MINNESOTA MUNICIPAL POWER AGENCY

Statements of Net Position

December 31, 2014 and 2013

Assets	**2014**	**2013**
Current assets:		
Cash	$ 23,534	32,678
Investments:		
Unrestricted funds:		
Revenue and operating funds	27,626,275	23,981,024
Rate stabilization	71,334,565	70,369,245
Other	9,129,642	27,209,367
Restricted funds	65,533,852	57,738,495
Power sales revenue receivables	16,329,840	17,030,963
Accrued interest receivable	347,857	323,009
Fuel stock	6,447,410	12,196,330
Material inventory	5,755,364	4,674,604
Prepaids	1,162,561	1,744,832
Other current assets	1,213,842	1,654,671
Escrow deposit	—	499,551
Insurance claim receivable	11,152,000	13,284,000
Total current assets	216,056,742	230,738,769
Noncurrent assets:		
Capital assets:		
Electric plant and equipment	761,317,916	713,208,591
Less accumulated depreciation and amortization	336,406,698	321,367,601
Electric plant and equipment – net	424,911,218	391,840,990
Construction work in progress	52,784,314	79,527,884
Total capital assets	477,695,532	471,368,874
Restricted investment funds	71,972,985	71,717,610
Total noncurrent assets	549,668,517	543,086,484
Total assets	765,725,259	773,825,253
Deferred Outflows		
Future recoverable costs – noncurrent	220,318,013	232,131,706
Accumulated decrease in fair value of derivative instruments – noncurrent	749,177	907,264
Total assets and deferred outflows	$ 986,792,449	1,006,864,223
Liabilities		
Current liabilities:		
Accounts payable – power production	$ 2,699,178	6,392,738
Accrued liabilities and other payables	30,253,167	11,877,723
Accrued interest payable	7,591,537	8,824,191
Notes payable	45,000,000	45,000,000
Current maturities of long-term debt	51,935,000	48,520,000
Total current liabilities	137,478,882	120,614,652
Long-term liabilities:		
Long-term debt, net	592,431,723	618,719,985
Derivative instruments – swap liability	749,177	907,264
Other long-term obligations	—	17,791,793
Total long-term liabilities	593,180,900	637,419,042
Total liabilities	730,659,782	758,033,694
Deferred Inflows		
Deferred credits rate stabilization – current	—	130,131
Gain on involuntary conversion of plant assets – current	3,239,108	3,209,701
Deferred credits rate stabilization – noncurrent	92,959,803	92,354,124
Gain on involuntary conversion of plant assets – noncurrent	61,543,043	64,194,017
Total deferred inflows	157,741,954	159,887,973
Total liabilities and deferred inflows	888,401,736	917,921,667
Net Position		
Net investment in capital assets	95,046,707	43,818,585
Restricted by bond agreements	66,830,123	58,779,391
Unrestricted	(63,486,117)	(13,655,420)
Total net position	98,390,713	88,942,556
Total liabilities, deferred inflows, and net position	$ 986,792,449	1,006,864,223

See accompanying notes to financial statements.

SOUTHERN MINNESOTA MUNICIPAL POWER AGENCY

Statements of Revenues, Expenses, and Changes in Net Position

Years ended December 31, 2014 and 2013

		2014	2013
Operating revenues, power sales	$	242,155,755	253,008,856
Operating expenses:			
Production fuel		46,410,022	7,111,814
Power production		67,471,136	120,112,839
Other operating expenses		56,568,777	49,892,022
Depreciation and amortization		16,339,677	15,232,595
Deferred costs expensed in current period		3,725,759	2,634,378
Total operating expenses		190,515,371	194,983,648
Operating income		51,640,384	58,025,208
Nonoperating (income) expenses:			
Investment earnings		(1,251,575)	(1,059,704)
Miscellaneous income		(1,219,580)	(1,209,449)
Interest expense		12,793,818	16,143,581
Amortization of long-term debt issuance costs		1,093,474	1,128,501
Amortization of discount/premium on long-term debt		25,646,738	25,013,451
Deferred costs expensed in current period		5,129,352	4,511,075
Total nonoperating expenses		42,192,227	44,527,455
Change in net position		9,448,157	13,497,753
Total net position, beginning of year		88,942,556	75,444,803
Total net position, end of year	$	98,390,713	88,942,556

See accompanying notes to financial statements.

SOUTHERN MINNESOTA MUNICIPAL POWER AGENCY

Statements of Cash Flows

Years ended December 31, 2014 and 2013

		2014	2013
Cash flows from operating activities:			
Receipts from members	$	200,030,282	199,904,137
Receipts from others		43,742,973	43,421,198
Payments for fuel		(40,661,102)	(8,594,541)
Payments for other power production		(72,245,456)	(123,014,060)
Payments for other operating expenses		(35,492,929)	(32,441,014)
Payments for maintenance		(7,372,698)	(7,519,673)
Payments in-lieu of property taxes		(7,331,476)	(7,140,254)
Net cash provided by operating activities		80,669,594	64,615,793
Cash flows from noncapital financing activity:			
Miscellaneous income		1,219,580	1,209,449
Net cash provided by noncapital financing activity		1,219,580	1,209,449
Cash flows from capital and related financing activities:			
Capital asset additions		(24,473,514)	(49,692,334)
Proceeds from issuance of notes payable		—	24,000,000
Principal payments for long-term debt		(48,520,000)	(44,285,000)
Interest payments		(16,503,962)	(18,793,724)
Net cash used in capital and related financing activities		(89,497,476)	(88,771,058)
Cash flows from investing activities:			
Proceeds from sale/maturity of investments		252,330,356	283,087,645
Purchase of investments		(246,457,476)	(271,154,930)
Interest received		1,226,727	1,029,693
Escrow withdrawals		499,551	9,991,012
Net cash provided by investing activities		7,599,158	22,953,420
Change in cash		(9,144)	7,604
Cash, beginning balance		32,678	25,074
Cash, ending balance	$	23,534	32,678
Reconciliation of operating income to net cash provided by operating activities:			
Operating income	$	51,640,384	58,025,208
Adjustments to reconcile operating income to net cash provided by operating activities:			
Depreciation and amortization		16,339,677	15,232,595
Deferred costs expensed in current period		3,725,759	2,634,378
Change in deferred credits		475,548	(8,131,052)
Changes in operating assets and liabilities:			
Power sales revenue receivables		701,123	(1,266,984)
Fuel stock		5,748,920	(1,482,727)
Material inventory		(1,080,760)	49,903
Prepaids		582,271	(223,374)
Other current assets		440,829	(285,485)
Accounts payable – power production		(3,693,560)	(2,951,124)
Accrued liabilities and other payables		5,789,403	3,014,455
Total adjustments		29,029,210	6,590,585
Net cash provided by operating activities	$	80,669,594	64,615,793
Supplemental disclosures of noncash items:			
Other long-term obligations due within one year included with accrued liabilities and other payables	$	12,586,041	—
Capitalized interest		2,477,490	1,578,828

See accompanying notes to financial statements.

(1) Organization and Significant Accounting Policies

(a) Organization and Operation

Southern Minnesota Municipal Power Agency (the Agency) was created as a municipal corporation and a political subdivision of the State of Minnesota by an agency agreement recorded with the Secretary of the State of Minnesota on June 2, 1977. The Agency's purpose is to secure an adequate, economical, and reliable supply of electric energy for its member municipalities. The Agency is made up of 18 Minnesota municipalities that purchase power from the Agency under power sales contracts.

The Agency sells power to its members under power sales contracts that initially extended to April 1, 2030. In December 2008, the board of directors approved a request for the member cities to consider extending their contracts an additional 20 years from April 1, 2030 to April 1, 2050. Of the 18 members, 15 have elected to extend their contracts. The board of directors approved the contract extensions in January 2011. The three members that have elected not to extend their contracts are cities of Austin, Rochester, and Waseca.

Under the terms of these contracts, with certain minor exceptions, the Agency is obligated to furnish, and each member is obligated to take and pay for, the total power and energy required by the member through the term of the contract. However, for the city of Rochester, the maximum amount of power required to be delivered by the Agency and taken and paid for by that member through the term of the contract is 216 megawatts. Beginning in 2016, the city of Austin will limit its maximum amount of power to 70 megawatts.

The Agency has entered into an ownership and operating agreement with an investor-owned utility, which entitles the Agency to a 41% undivided ownership interest in Sherburne County Generating Unit No. 3 (Sherco 3). The 41% undivided ownership interest is included in capital assets. The Agency's share of the total net tested capability of Sherco 3 is approximately 373 megawatts. The Agency also purchases some power for resale under capacity purchase agreements with its members, who own and operate generating units.

On August 6, 2014, the Agency formed SMMPA Wisconsin, LLC (the LLC), which is a wholly owned subsidiary of the Agency. The purpose of the LLC is to undertake investment in, and ownership of, electric transmission facilities in the state of Wisconsin. Companies are required to be public utilities incorporated in Wisconsin in order to own utility facilities in the state. On February 12, 2015, the Public Service Commission of Wisconsin (the Commission) approved a request by the LLC to be designated as a public utility in Wisconsin. The LLC will not provide retail electric service. As of December 31, 2014, the LLC had not engaged in any business transactions, and therefore, there were no effects on the Agency's financial statements.

(b) Basis of Accounting

The Agency follows the Federal Energy Regulatory Commission's Uniform System of Accounts and maintains accounting records on an accrual basis, in conformity with U.S. generally accepted accounting principles, as applicable to governmental entities, including the application of the Government Accounting Standards Board (GASB) Statement No. 62, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA*

Pronouncements, as the guidance relates to regulated operations. The guidance allows for deferral of revenues and expenses to future periods in which the revenues are earned or the expenses are recovered through the rate-making process.

(c) Capital Assets

Capital assets are recorded at cost, including interest capitalized on borrowed funds during construction.

In reporting its capital assets, the Agency follows the guidance of GASB Statement No. 42, *Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries* (GASB 42). In November 2011, during post-overhaul testing of Sherco 3, a failure occurred within the unit's steam turbine and generator. The failure resulted in a fire on the turbine and generator. The turbine and generator were extensively damaged and required significant restoration. As a consequence of the Sherco 3 turbine and generator failure, Sherco 3 was idled while the unit underwent restoration. Sherco 3 was resynchronized to the electrical grid on September 4, 2013. Under GASB 42, the capital assets damaged by the turbine and generator failure were considered impaired. The Agency has utilized the restoration cost approach to measure the impairment. Under the restoration cost approach, the amount of the impairment is derived from the estimated costs to restore the utility of the affected capital assets.

The property and casualty insurer of the Sherco 3 turbine and generator has acknowledged that the damage is subject to insurance coverage. Accordingly, the Agency has received cumulative insurance proceeds of $82.0 million, and $79.5 million as of December 31, 2014 and 2013, respectively. The estimated remaining insurance claim receivable was $11.2 million and $13.3 million for those years. The Agency has established a regulatory liability for the difference between the amount of the estimated insurance recovery and the carrying value of the capital assets impaired and reported such amount at December 31, 2014 and 2013 in the statements of net position as a deferred gain on involuntary conversion of plant assets of $64.8 million and $67.4 million, respectively.

The original cost of utility plant retired, plus removal costs, less salvage, is charged to accumulated depreciation. Depreciation is provided over the estimated useful life of the utility plant by use of the straight-line method. Depreciation is deferred to the extent that it exceeds current principal payments of the Agency's revenue bonds. This method correlates with the Agency's rate-making philosophy in that debt service requirements, as opposed to depreciation or amortization, are a cost for rate-making purposes.

(d) Deposits and Investments

Deposits and investments include cash, money market funds, and investments. Investments are reported at fair value based on quoted market prices.

(e) Restricted Investments

The Agency's bond resolution requires the segregation of bond proceeds and prescribes the application of the Agency's revenues. Amounts classified as restricted funds on the statements of net position represent investments whose use is restricted by the bond resolution. It is the Agency's policy to use restricted resources first for debt service, and then unrestricted resources as they are needed.

(f) Power Sales Revenue Receivables

Power sales revenue receivables, representing power sales to members for the period between the last billing date and the end of the period, are accrued in the period sold.

(g) Fuel Stock and Material Inventory

Fuel stock is valued at average cost, which does not exceed market. Material inventory is valued at average cost, which does not exceed market.

(h) Escrow Deposit

In 2012, the Agency deposited funds into an equipment purchase escrow account with J. P. Morgan related to a portion of the equipment needed for the Fairmont Energy Station. The final escrow payment was made in 2014.

(i) Compensated Absences

The Agency records a liability for vacation as the benefits accrue to employees. The Agency compensates all employees upon termination for unused vacation. Employees who have been employed by the Agency for at least five consecutive years who are leaving the Agency and who are eligible to retire as defined by the Public Employees' Retirement Association, or the estate of any such employee who dies while employed by the Agency, will receive a contribution to their retirement healthcare savings equal to one-third of the value of their remaining unused sick leave.

(j) Income Taxes

The Agency is exempt from federal and state income taxes, as it is a political subdivision of the State of Minnesota.

(k) Rates

The Agency designs its wholesale electric service rates to recover estimated costs of providing power supply services. In compliance with the power sales contract, rates and charges for providing wholesale power supply are reviewed annually by the Agency's board of directors. Any changes must be approved by the board of directors. In accordance with its senior bond resolution, the Agency shall establish rates that, together with other revenues, are reasonably expected to pay its operating costs (not including depreciation and amortization) and at least 1.10 times its aggregate debt service requirements. Power supply services provided by the Agency are not subject to state or federal rate regulation.

(l) Operating Revenues and Expenses

Operating revenues result from exchange transactions associated with the principal activity of the Agency, the sale of electricity. Reported operating revenues are affected by the contributions to, or distributions from, the rate stabilization account. Operating expenses are defined as expenses directly related to, or incurred in support of, the production and transmission of electricity to the participating members. All other expenses are classified as nonoperating expenses.

(Continued)

(m) Deferred Costs to be Recovered in Future Periods

Costs in excess of the amounts currently billable to the members are to be recovered from future revenues by setting rates sufficient to provide funds for the related debt service requirements. As allowed through the applications of the provisions of GASB 62, current costs in excess of funding are deferred and shown as deferred costs to be recovered in future periods on the accompanying statements of net position and as expenses to be recovered in future periods on the statements of revenues, expenses, and changes in net position. These costs represent depreciation of electric plant and equipment, amortization of long-term debt issuance costs, and amortization of long-term debt discount/premium in excess of amounts currently billed to members.

(n) Deferred Credits – Rate Stabilization

The Agency intends for its electric service rates to recover costs, as defined above, of providing power supply services. As part of its rate-making process, the Agency budgets an amount as a contribution to or a distribution from the rate stabilization account. The amount of the contribution to, or distribution from, the rate stabilization account is determined by the amount of revenues needed to meet the 1.10 coverage required by the debt service requirements. Revenue associated with amounts designated as contributions to the rate stabilization account are deferred and reported as an addition to the deferred credits-rate stabilization account on the statements of net position. In the event actual operating expenses exceed the 1.10 coverage required by the debt service requirements, the Agency has the ability to supplement its operating revenues, power sales, through the use of accumulations in its rate stabilization account. Usage of the rate stabilization results in the recognition of additional amounts of operating revenues, power sales, and a corresponding reduction in deferred credits-rate stabilization on the statements of net position. For the years ended December 31, 2014 and 2013, the Agency contributed $475,548 to, and distributed $8,131,052 from, its rate stabilization account, respectively.

(o) Deferred Gain on Involuntary Conversion of Plant Assets

In November 2011, the Agency experienced damage to its turbine and generator at Sherco 3. Pursuant to GASB 62, the Agency established a regulatory liability, which represents the deferred gain resulting from the involuntary conversion of plant assets. The gain will be amortized by the Agency into income over the remaining life of Sherco 3 at the time of the incident.

(p) Cash Flows

For purposes of the statements of cash flows, the Agency does not consider investments in money market funds or other investments with original maturities of three months or less as cash equivalents.

(q) Use of Estimates

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

(r) Recently Issued Accounting Standards

In June 2012, GASB issued Statement No. 68, *Accounting and Financial Reporting for Pensions – an Amendment of GASB No. 27*. The Agency will be required to report a liability for their proportionate share of the net pension liability of the defined benefit pension plan (note 7) as well as the related pension expense and any deferred inflows or deferred outflows of resources. The Agency historically has only included their required contributions as an expense. The Agency will adopt GASB 68 effective January 1, 2015.

(2) Deposits and Investments

The agency agreement that established the Agency and the bond resolution, under which the Power Supply System Revenue Bonds were issued, provides for the creation and maintenance of certain funds and accounts. The funds and accounts consist principally of deposits and investments in accordance with the agency agreement, bond resolution, and applicable state law. Funds and accounts are reported in the statements of net position as follows:

		2014	2013
Current assets:			
Cash	$	23,534	32,678
Investments:			
Unrestricted funds:			
Revenue and operating funds		27,626,275	23,981,024
Rate stabilization		71,334,565	70,369,245
Other		9,129,642	27,209,367
Total unrestricted funds		108,090,482	121,559,636
Restricted funds:			
Debt service account		65,224,463	57,429,170
Debt service reserve		309,389	309,325
Total restricted funds		65,533,852	57,738,495
Total current investments		173,647,868	179,330,809
Noncurrent investments:			
Restricted funds:			
Debt service reserve		71,972,985	71,717,610
Total noncurrent investments		71,972,985	71,717,610
Total	$	245,620,853	251,048,419

(a) Deposits

In accordance with applicable Minnesota Statutes, the Agency maintains deposits at depository banks authorized by the Agency's board of directors.

Minnesota Statutes require that all deposits be protected by federal deposit insurance, corporate surety bond, or collateral. The market value of collateral pledged must equal 110% of the deposits not covered by federal deposit insurance or corporate surety bonds.

Authorized collateral includes treasury bills, notes, and bonds; issues of U.S. government agencies; general obligations rated "A" or better; revenue obligations rated "AA" or better; irrevocable standard letters of credit issued by the Federal Home Loan Bank; and certificates of deposit. Minnesota Statutes require that securities pledged as collateral be held in safekeeping in a restricted account at the Federal Reserve Bank or in an account at a trust department of a commercial bank or other financial institution that is not owned or controlled by the financial institution furnishing the collateral.

Deposit balances are as follows:

	2014	2013
Carrying amount of cash	$ 23,534	32,678
Bank balance	597,548	237,720

At December 31, 2014 and 2013, all deposits for the Agency were insured or collateralized by securities held by the Agency.

(b) Investments

Minnesota Statutes authorize the Agency to invest in the following types of investments:

- Direct obligations or obligations guaranteed by the United States of America or its agencies
- Shares of investment companies registered under the Federal Investment Company Act of 1940 whose only investments are securities described in (a) above
- General obligations of the State of Minnesota or any of its municipalities
- Bankers' acceptances of U.S. banks eligible for purchase by the Federal Reserve System
- Commercial paper issued by U.S. corporations or their Canadian subsidiaries, of the highest quality and maturing in 270 days or less
- Guaranteed investment contracts issued or guaranteed by U.S. commercial banks or domestic branches of foreign banks or U.S. insurance companies or their subsidiaries
- Repurchase or reverse repurchase agreements with banks that are members of the Federal Reserve System with capitalization exceeding $10,000,000, a primary reporting dealer in U.S. government securities to the Federal Reserve Bank of New York, or certain Minnesota securities broker-dealers
- Future contracts sold under authority of Minnesota Statutes 471.56, subd. 5.

(Continued)

The Agency's investments are potentially subject to various risks, including the following:

- Custodial credit risk – The risk that in the event of a failure of the counterparty to an investment transaction (typically a brokerage firm or financial institution), the Agency would not be able to recover the value of the investment or collateral securities. The Agency's investment policy does not limit the value of investments that may be held by an outside party.
- Credit risk – The risk that an issuer or other counterparty to an investment will not fulfill its obligations.
- Concentration of credit risk – The risk of loss attributed to the magnitude of the Agency's investment in a single issuer.
- Interest rate risk – The risk that changes in interest rates will adversely affect the fair value of an investment.

The Agency has an internal investment policy that limits investment choices and addresses these potential risks beyond the statutory limitations described above. The Agency's policy requires that investments be diversified to avoid unreasonable risks inherent in overinvesting in specific instruments, individual financial institutions, or maturities. For U.S. government and federal agency securities, the Agency places no limit on the amount that may be invested in any one issuer. The maximum percentage in which the portfolio can be invested, in specific instruments, is as follows:

U.S. government and federal agency securities	100%
Public agency or municipality, new housing authority bonds, and project notes	50
Direct or general obligation of any U.S. state	50
Commercial paper	50
Certificates of deposit – negotiable or nonnegotiable	50
Bankers' acceptances	50
Repurchase agreements	50

Investments are summarized as follows:

	2014		2013	
	Amortized cost	**Fair value**	**Amortized cost**	**Fair value**
Money market funds	$ 82,027,844	82,027,844	70,029,211	70,029,211
U.S. government securities	163,723,814	163,569,475	181,595,327	180,986,530
Total investments	$ 245,751,658	245,597,319	251,624,538	251,015,741

The following table presents the Agency's investment balances at December 31, 2014 and information relating to potential investment risks:

Investment	Interest rate risk: Less than 1 year	Interest rate risk: 1–5 years	Concentration risk: Over 5% of portfolio	Credit quality rating: S&P	Credit quality rating: Moody's	Carrying value
Government securities:						
Federal Home Loan Bank	$ —	28,898,250	11.8%	AA+	AAA	$ 28,898,250
Federal Farm Credit Bank	—	21,917,510	8.9%	AA+	AAA	21,917,510
Federal Home Loan Mortgage Corporation	—	20,967,620	8.5%	AA+	AAA	20,967,620
Federal National Mortgage Association	10,113,800	41,365,805	16.8%	AA+	AAA	51,479,605
United States Treasury Note	—	40,306,490	16.4%	AA+	AAA	40,306,490
Cash management funds:						
Wells Fargo Advantage Treasury Plus Money Market	82,027,844	—	N/A	N/R	N/R	82,027,844
						$ 245,597,319

N/A Not applicable
N/R Not rated

The foregoing investments are held by the Agency's counterparty, but not in the name of the Agency.

The following table presents the Agency's investment balances at December 31, 2013 and information relating to potential investment risks:

Investment	Interest rate risk: Less than 1 year	Interest rate risk: 1–5 years	Concentration risk: Over 5% of portfolio	Credit quality rating: S&P	Credit quality rating: Moody's	Carrying value
Government securities:						
Federal Home Loan Bank	$ —	12,944,470	5.2%	AA+	AAA	$ 12,944,470
Federal Home Loan Bank Discount Notes	14,998,710	—	6.0%	A-1+	P-1	14,998,710
Federal Farm Credit Bank	2,002,080	25,916,970	11.1%	AA+	AAA	27,919,050
Federal Home Loan Mortgage Corporation	12,036,120	20,835,590	13.1%	AA+	AAA	32,871,710
Federal National Mortgage Association	3,998,120	73,214,470	30.8%	AA+	AAA	77,212,590
United States Treasury Bill	4,999,800	—	No	AA+	AAA	4,999,800
United States Treasury Note	10,040,200	—	No	AA+	AAA	10,040,200
Cash management funds:						
Wells Fargo Advantage Treasury Plus Money Market	70,029,211	—	N/A	N/R	N/R	70,029,211
						$ 251,015,741

N/A Not applicable
N/R Not rated

The foregoing investments are held by the Agency's counterparty, but not in the name of the Agency.

(3) Capital Assets

Capital asset activity was as follows:

2014	Beginning balance	Additions	Transfers	Retirements	Ending balance
Nondepreciable:					
Land and land rights	$ 5,928,698	154,300	221,760	—	6,304,758
Construction work in progress	79,527,884	28,156,617	(54,900,187)	—	52,784,314
Depreciable:					
Utility plant in service	707,279,893	1,033,314	54,678,427	(7,978,476)	755,013,158
Less accumulated depreciation for utility plant in service	(321,367,601)	(18,138,727)	—	3,099,630	(336,406,698)
Capital assets, net	$ 471,368,874	11,205,504	—	(4,878,846)	477,695,532

2013		Beginning balance	Additions	Transfers	Retirements	Ending balance
Nondepreciable:						
Land and land rights	$	5,928,698	—	—	—	5,928,698
Construction work in progress		91,075,738	89,126,473	(100,674,327)	—	79,527,884
Depreciable:						
Utility plant in service		615,878,481	100,674,327	—	(9,272,915)	707,279,893
Less accumulated depreciation for utility plant in service		(309,607,181)	(13,881,512)	—	2,121,092	(321,367,601)
Capital assets, net	$	403,275,736	175,919,288	(100,674,327)	(7,151,823)	471,368,874

(4) Long-Term Debt

The Agency has issued the following Power Supply System Revenue Bonds to finance portions of its construction activities:

		2014	2013
Series 2002A, 2.00% – 5.25%, due January 1, 2004 to 2018	$	142,535,000	185,430,000
Series 2006A, 3.65% – 4.25%, due January 1, 2011 to 2027		30,945,000	32,925,000
Series 2009A, 2.00% – 5.50%, due January 1, 2011 to 2030		52,000,000	54,145,000
Taxable Series 2010A, (Build America Bonds), 3.774% – 5.926%, due January 1, 2018 to 2043		67,990,000	67,990,000
Series 2010B (Tax-Exempt), 2.00% – 4.00%, due January 1, 2013 to 2017		4,760,000	6,260,000
		298,230,000	346,750,000
Less unamortized discount/premium		6,683,512	10,791,615
		291,546,488	335,958,385
Series 1994A, 6.65% – 6.70%, CABs due January 1, 2019 to 2027		503,300,000	503,300,000
Series 2002A, 4.65% CABs, due January 1, 2018		55,320,000	55,320,000
		558,620,000	558,620,000
Less unamortized discount		205,799,765	227,338,400
		352,820,235	331,281,600
		644,366,723	667,239,985
Less current maturities		51,935,000	48,520,000
	$	592,431,723	618,719,985

Power Supply System Revenue Bonds are the major source of financing for the Agency's construction activities. These are secured by all funds and revenues of the Agency derived from the ownership and operation of its power supply system.

Long-term debt issuance costs attributable to refunded bonds, long-term debt issuance costs, and the discount/premium on long-term debt are amortized over the terms of the related bond issues under the effective-interest method.

Revenue bond debt service requirements to maturity are as follows:

		Principal	Interest
2015	$	51,935,000	15,229,145
2016		55,530,000	12,583,031
2017		59,305,000	9,767,729
2018		62,985,000	6,771,988
2019		64,210,000	6,466,714
2020–2024		324,835,000	28,182,512
2025–2029		189,330,000	19,587,666
2030–2034		17,765,000	11,763,546
2035–2039		15,890,000	7,360,388
2040–2043		15,065,000	2,274,399
	$	856,850,000	119,987,118

Long-term liability activity for the years ended December 31, 2014 and 2013 was as follows:

2014		Beginning balance	Additions	Reductions	Ending balance
Long-term revenue bonds	$	905,370,000	—	(48,520,000)	856,850,000
Less:					
Current maturities		(48,520,000)	(3,415,000)	—	(51,935,000)
Unamortized discount, net		(238,130,015)	—	25,646,738	(212,483,277)
Long-term revenue bonds, net	$	618,719,985	(3,415,000)	(22,873,262)	592,431,723
Derivative instruments – swap liability	$	907,264	—	(158,087)	749,177
Other long-term obligations		17,791,793	—	(17,791,793)	—

(Continued)

2013	Beginning balance	Additions	Reductions	Ending balance
Long-term revenue bonds	$ 949,655,000	—	(44,285,000)	905,370,000
Less:				
Current maturities	(44,285,000)	(4,235,000)	—	(48,520,000)
Unamortized discount, net	(263,143,466)	—	25,013,451	(238,130,015)
Long-term revenue bonds, net	$ 642,226,534	(4,235,000)	(19,271,549)	618,719,985
Derivative instruments – swap liability	$ 817,280	89,894	—	907,174
Other long-term obligations	23,288,281	—	(5,496,488)	17,791,793

(5) Notes Payable

Since 1995, the Agency is authorized to borrow and reborrow from time to time up to $68,000,000 at any one time outstanding, evidenced by the issuance of Commercial Paper Notes, Series B. The Commercial Paper Notes, Series B bear interest payable at maturity at a maximum rate not in excess of 15% per annum, and shall mature not more than 270 days after issuance. The interest rate on the $45,000,000 outstanding at December 31, 2014 was 0.08%.

Commercial Paper Notes, Series B activity for the years ended December 31, 2014 and 2013 was as follows:

Activity for fiscal year	Beginning balance	Issues	Maturities	Ending balance
2014	$ 45,000,000	270,000,000	(270,000,000)	45,000,000
2013	21,000,000	150,000,000	(126,000,000)	45,000,000

(6) Derivative Instruments

The Agency applies GASB Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments*. The tables below summarize derivative instrument activity for the years ended December 31, 2014 and 2013 and balances at end of 2014 and 2013:

	Changes in fair value for year ended December 31, 2014		Fair value at December 31, 2014		
	Classification	Amount	Classification	Amount	Notional amount
Cash flow hedges:					
Pay-fixed interest rate swaps	Deferred outflow	$ (158,087)	Long-term liabilities	$ (749,177)	17,435,000

	Changes in fair value for year ended December 31, 2013			Fair value at December 31, 2013			Notional
	Classification		Amount	Classification		Amount	amount
Cash flow hedges:							
Pay-fixed interest rate swaps	Deferred outflow	$	89,984	Long-term liabilities	$	(907,264)	19,415,000

The fair values of the interest rate swaps were estimated using the zero-coupon method. This method calculates the future net settlement payments required by the swap, assuming that the current forward rates implied by the yield curve correctly anticipate future spot interest rates. These payments are then discounted using the spot rates implied by the current yield curve for hypothetical zero-coupon bonds due on the date of each future net settlement on the swaps.

(a) Objectives

In order to better manage its interest rate exposure and to reduce the overall costs of its financings, the Agency has entered into five separate pay-fixed, receive-variable interest rate swaps.

(b) Terms

Certain key terms relating to the outstanding hedging derivative instruments are presented below:

Associated financing issue		Notional amounts	Effective date	Fixed rate paid	Rate received	Swap termination date	Final maturity of bonds
Hedging derivatives:							
Cash flow hedges, pay-fixed interest rate swaps:							
Series 2006A	$	3,145,000	9/6/2006	3.82	CPI Rate (1) + 0.62%	1/1/2015	1/1/2015
Series 2006A		4,230,000	9/6/2006	3.87	CPI Rate (1) + 0.66%	1/1/2016	1/1/2016
Series 2006A		5,030,000	9/6/2006	3.93	CPI Rate (1) + 0.71%	1/1/2017	1/1/2017
Series 2006A		3,395,000	9/6/2006	3.98	CPI Rate (1) + 0.76%	1/1/2018	1/1/2018
Series 2006A		1,635,000	9/6/2006	4.02	CPI Rate (1) + 0.79%	1/1/2019	1/1/2019
Total	$	17,435,000					

(1) CPI rate is defined by the swaps' letter agreement and is generally defined as the percentage change in the CPI index over a rolling 12-month period computed every six months beginning with the semiannual calculation on January 1, 2007 using the October 2006 and 2005 CPI indices.

(c) Credit Risk

Credit risk can be measured by actual market value exposure or theoretical exposure. When the fair value of any swap has a positive market value, then the Agency is exposed to the actual risk that the counterparty will not fulfill its obligations. As of December 31, 2014, the Agency had no net exposure to actual credit risk on its hedging derivatives because each had a negative fair value.

(d) Interest Rate Risk

All hedging derivatives are pay-fixed, receive-variable, cash flow hedges hedging a portion of the Agency's variable-rate debt. The Agency believes it has significantly reduced interest rate risk attributable to the principal amount being hedged by entering into these pay-fixed, receive-variable interest rate swaps.

(e) Basis Risk

The Agency is exposed to basis risk when the variable interest received on a swap is based on a different index than the variable interest rate to be paid on the associated variable rate debt obligation. As of December 31, 2014, the associated debt used the same index for all Consumer Price Index (CPI) referenced swaps. As a result, there is no significant exposure to basis risk as of December 31, 2014.

(f) Termination Risk

The Agency or counterparty may terminate any of the swaps if the other party fails to perform under the terms of the contract. In such cases, the Agency may owe or be due a termination payment depending on the fair value of the swap at that time. The termination payment due to a counterparty may not be equal to the fair value. If any of the swaps were terminated, the associated variable rate financings would no longer carry synthetic interest rates.

(g) Rollover Risk

The Agency is exposed to rollover risk on swaps that mature or may be terminated prior to the maturity of the associated financings. When these swaps terminate, or in the case of the termination option, if the counterparty exercises its option, the Agency will not realize the synthetic rate offered by the swaps on the underlying issues. The Agency is exposed to rollover risk on its swaps should they be terminated prior to the maturity of the associated financings.

(h) Foreign Currency Risk

All derivatives are denominated in U.S. dollars, and therefore, the Agency is not exposed to foreign currency risk.

(7) Pension Plan

(a) Plan Description

All full-time and certain part-time employees of the Agency are covered by a defined benefit plan administered by Public Employees' Retirement Association (PERA). PERA administers the General Employees Retirement Fund (GERF), which is a cost-sharing, multiple-employer retirement plan. This plan is established and administered in accordance with Minnesota Statutes, Chapters 353 and 356.

GERF members belong to either the Coordinated Plan or the Basic Plan. Coordinated Plan members are covered by Social Security, and Basic Plan members are not. All new members must participate in the Coordinated Plan.

PERA provides retirement benefits, as well as disability benefits, to members, and benefits to survivors upon death of eligible members. Benefits are established by state statute, and vest after three years of credited service. The defined retirement benefits are based on a member's highest average salary for any five successive years of allowable service, age, and years of credit at termination of service.

Two methods are used to compute benefits for PERA's Coordinated and Basic Plan members. The retiring member receives the higher of a step-rate benefit accrual formula (Method 1) or a level accrual formula (Method 2). Under Method 1, the annuity accrual rate for a Basic Plan member is 2.2% of average salary for each of the first 10 years of service and 2.7% for each remaining year. The annuity accrual rate for a Coordinated Plan member is 1.2% of average salary for each of the first 10 years and 1.7% for each remaining year. Under Method 2, the annuity accrual rate is 2.7% of average salary for Basic Plan members and 1.7% for Coordinated Plan members for each year of service. For GERF members hired prior to July 1, 1989, whose annuity is calculated using Method 1, a full annuity is available when age plus years of service equal 90. Normal retirement age is 65 for Basic and Coordinated members hired prior to July 1, 1989. Normal retirement age is the age for unreduced Social Security benefits capped at 66 for Coordinated members hired on or after July 1, 1989. A reduced retirement annuity is also available to eligible members seeking early retirement.

There are different types of annuities available to members upon retirement. A single-life annuity is a lifetime annuity that ceases upon the death of the retiree for which no survivor annuity is payable. There are also various types of joint and survivor annuity options available which will be payable over joint lives. Members may also leave their contributions in the fund upon termination of public service in order to qualify for a deferred annuity at retirement age. Refunds of contributions are available at any time to members who leave public service, but before retirement benefits begin.

The benefit provisions stated in the previous paragraphs of this section are current provisions and apply to active plan participants. Vested, terminated employees who are entitled to benefits but are not receiving them yet are bound by the provisions in effect at the time they last terminated their public service.

PERA issues a publicly available financial report that includes financial statements and required supplementary information for GERF. That report may be obtained on the Internet at www.mnpera.org; by writing to PERA at 60 Empire Drive #200, St. Paul, MN 55103-2088; or by calling (651) 296-7460 or 1-800-652-9026.

(b) Funding Policy

Minnesota Statutes Chapter 353 sets the rates for employer and employee contributions. These statutes are established and amended by the state legislature. The Agency makes annual contributions to the pension plans equal to the amount required by state statutes. GERF Basic Plan members and Coordinated Plan members are required to contribute 9.1% and 6.25%, respectively, of their annual covered salary in 2014. In 2014, the Agency is required to contribute the following percentages of annual covered payroll: 11.78% for Basic Plan members and 7.25% for Coordinated Plan members. The Agency's contributions to GERF for the years ended December 31, 2014 and 2013 were $343,371 and $329,166, respectively. The Agency's contributions were equal to the contractually required contributions for each year as set by state statute.

(8) Deferred Compensation Plans

The Agency offers its employees a deferred compensation plan created in accordance with Internal Revenue Code Section 457. The plan, available to all Agency employees, permits them to defer a portion of their salary until future years. The deferred compensation is not available to employees until termination, retirement, death, or unforeseeable emergency. All assets and income of the plan are held in a trust established for the exclusive benefit of eligible employees and their beneficiaries in accordance with Internal Revenue Code Section 457(g). Participants' rights under the plan are equal to the fair market value of the deferred account for each participant. The trust shall not revert to the Agency or be used for or diverted to purposes other than the exclusive benefit of participants and their beneficiaries. The plan is managed by third-party administrators. Plan assets were $10,764,009 and $9,944,972 at December 31, 2014 and 2013, respectively. The Agency contributed $106,649 and $103,889 to the plan for the years ended December 31, 2014 and 2013, respectively.

During 2011, the Agency adopted a tax qualified defined contribution plan created in accordance with Internal Revenue Code Section 401(a). The plan, available to all Agency employees with six months of continuous service, permits them to defer a portion of their salary until future years. The amount deferred is not available to employees until termination, retirement, death, or unforeseeable emergency. Participants' rights under the plan are equal to the fair market value of the account for each participant. The plan is managed by third-party administrators. Plan assets were $1,409,018 and $1,033,199 at December 31, 2014 and 2013, respectively. The Agency contributed $214,570 and $207,472 to the plan for the years ended December 31, 2014 and 2013, respectively.

(9) Risk Management

The Agency is exposed to various risks of loss related to torts; theft of, damage to, and destruction of assets; errors and omissions; injuries to employees and others; and natural disasters. Cash and investments held in the Agency's unrestricted funds are available to cover uninsured losses. As noted in note (1)(c), in November 2011, the Agency experienced damage to Sherco 3's turbine and generator that is subject to insurance coverage. The estimated insurance claim receivable, net of applicable deductibles, has been reported in the statements of net position.

The Agency continues to carry commercial insurance for other risks of loss, including workers' compensation, property and liability, and employee health and accident. Settled claims resulting from these risks have not exceeded commercial insurance coverage in any of the past three fiscal years.

(Continued)

(10) Commitments

In 2012, the Agency entered into various agreements to participate in the construction of a 345 kV and 161 kV high voltage transmission line project and to suspend further investment obligations under a shared transmission agreement. The Agency's commitment for its portion of the high voltage transmission line construction project costs and investment obligations under the shared transmission agreement together are approximately $70.0 million. As of December 31, 2014 and 2013, the Agency had accrued approximately $12.6 million and $17.8 million, respectively, for this investment obligation associated with the shared transmission agreement and the high voltage transmission line project. When the high voltage transmission line project is completed in 2016, the parties have agreed to freeze the investment obligations and suspend the shared transmission agreement, which will alleviate the Agency's future investment obligations under this agreement.

(11) Contingency

The Agency purchases coal for its jointly owned Sherco Unit 3 from Western Fuels Association, a not-for profit cooperative that supplies coal and transportation services to consumer-owned electric utilities (Western Fuels). Western Fuels contracts with Absaloka Coal, LLC, a wholly owned subsidiary of Westmoreland Coal Company (Westmoreland) for deliveries of coal from its Absaloka coal mine to Sherco 3. Following the catastrophic failure of the Sherco 3 turbine and generator in November of 2011, Western Fuels invoked the force majeure clause of its contract with Westmoreland and halted deliveries of coal while the unit was undergoing restoration. In November 2014, the Agency was provided with a notice of a demand for arbitration and related pleadings seeking to pursue a claim for monetary damages against the Agency, Western Fuels and Northern States Power Company d/b/a Xcel Energy (Xcel), the co-owner of Sherco 3. The demand was made by certain insurance companies as subrogees for Westmoreland. The Westmoreland insurers claim that they incurred significant damages because of payments made to Westmoreland under a business interruption insurance policy when purchases of coal were interrupted

Because the Westmoreland insurers have only made an aggregate claim for damages against Xcel, Western Fuels, and the Agency, it is not possible to determine the amount of the claim, or the portion of damages, for which the Agency might be claimed to be liable. The Agency has significant procedural, substantive, and contractual defenses to the Westmoreland claims, and intends to defend the demand for arbitration vigorously. Because the potential liability cannot be reasonably estimated and because management of the Agency believes that the probability of a material adverse judgment against the Agency is remote, no liability has been reflected in the Agency's financial statements for this matter.

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SOUTHERN MINNESOTA MUNICIPAL POWER AGENCY

Statements of Net Position

June 30, 2015 and 2014

Assets	**2015**	**2014**
Current assets:		
Cash	$ 27,357	32,941
Investments:		
Unrestricted funds:		
Revenue and operating funds	26,222,576	25,407,209
Rate stabilization	58,003,795	73,447,751
Other	26,608,089	18,911,044
Restricted funds	34,409,327	33,919,480
Power sales revenue receivables	17,763,409	17,626,054
Accrued interest receivable	316,094	311,939
Fuel stock	15,634,986	3,163,949
Material inventory	5,816,372	4,676,947
Prepaids	4,208,992	4,126,530
Other current assets	960,613	1,101,938
Escrow deposit	—	499,551
Insurance claim receivable	11,152,000	13,284,000
Total current assets	201,123,610	196,509,333
Noncurrent assets:		
Capital assets:		
Electric plant and equipment	758,095,617	729,580,196
Less accumulated depreciation and amortization	342,124,063	326,935,094
Electric plant and equipment – net	415,971,554	402,645,102
Construction work in progress	61,083,789	74,555,826
Total capital assets	477,055,343	477,200,928
Restricted investment funds	71,775,775	72,113,270
Investment in SMMPA WI LLC	2,000	—
Total noncurrent assets	548,833,118	549,314,198
Total assets	749,956,728	745,823,531
Deferred Outflows		
Future recoverable costs – noncurrent	213,078,958	225,515,146
Accumulated decrease in fair value of derivative instruments – noncurrent	669,569	575,344
Total assets and deferred outflows	$ 963,705,255	971,914,021
Liabilities		
Current liabilities:		
Accounts payable – power production	$ 5,920,570	5,562,649
Accrued liabilities and other payables	23,372,069	10,450,325
Accrued interest payable	6,272,306	7,594,411
Notes payable	68,000,000	45,000,000
Current maturities of long-term debt	55,530,000	51,935,000
Total current liabilities	159,094,945	120,542,385
Long-term liabilities:		
Long-term debt, net	549,772,839	579,316,430
Derivative instruments – swap liability	669,569	575,344
Other long-term obligations	—	17,791,793
Total long-term liabilities	550,442,408	597,683,567
Total liabilities	709,537,353	718,225,952
Deferred Inflows		
Deferred credits rate stabilization – current	—	130,131
Gain on involuntary conversion of plant assets – current	3,239,108	3,224,404
Deferred credits rate stabilization – noncurrent	87,883,881	94,051,624
Gain on involuntary conversion of plant assets – noncurrent	59,923,489	62,574,464
Total deferred inflows	151,046,478	159,980,623
Total liabilities and deferred inflows	860,583,831	878,206,575
Net Position		
Net investment in capital assets	146,384,490	97,842,422
Restricted by bond agreements	35,508,388	35,356,036
Unrestricted	(78,771,454)	(39,491,012)
Total net position	103,121,424	93,707,446
Total liabilities, deferred inflows, and net position	$ 963,705,255	971,914,021

SOUTHERN MINNESOTA MUNICIPAL POWER AGENCY

Statements of Revenues, Expenses, and Changes in Net Position

Years ended June 30, 2015 and 2014

		2015	**2014**
Operating revenues, power sales	$	114,309,919	121,690,135
Operating expenses:			
Production fuel		21,687,406	26,465,396
Power production		26,239,364	33,133,999
Other operating expenses		29,944,972	26,142,059
Depreciation and amortization		7,937,877	8,092,974
Deferred costs expensed in current period		2,888,277	2,041,622
Total operating expenses		88,697,896	95,876,050
Operating income		25,612,023	25,814,085
Nonoperating (income) expenses:			
Investment earnings		(683,944)	(613,420)
Miscellaneous income		(606,050)	(607,240)
Interest expense		5,232,460	6,436,952
Amortization of long-term debt issuance costs		512,660	534,597
Amortization of discount/premium on long-term debt		12,871,116	12,531,445
Deferred costs expensed in current period		3,555,070	2,766,861
Total nonoperating expenses		20,881,312	21,049,195
Change in net position		4,730,711	4,764,890
Total net position, beginning of year		98,390,713	88,942,556
Total net position, end of year	$	103,121,424	93,707,446

APPENDIX C

U. S. BANK NATIONAL ASSOCIATION

U.S. Bank National Association ("USBNA") is a national banking association organized under the laws of the United States and is the largest subsidiary of U.S. Bancorp. At September 30, 2015, USBNA reported total assets of $411 billion, total deposits of $305 billion and total shareholders' equity of $42 billion. The foregoing financial information regarding USBNA has been derived from and is qualified in its entirety by the unaudited financial information contained in the Federal Financial Institutions Examination Council report Form 031, Consolidated Report of Condition and Income for a Bank with Domestic and Foreign Offices ("Call Report"), for the quarter ended September 30, 2015. The publicly available portions of the quarterly Call Reports with respect to USBNA are on file with, and available upon request from, the FDIC, 550 17th Street, NW, Washington, D.C. 20429 or by calling the FDIC at (877) 275-3342. The FDIC also maintains an Internet website at www.fdic.gov that contains reports and certain other information regarding depository institutions such as USBNA. Reports and other information about USBNA are available to the public at the offices of the Comptroller of the Currency at One Financial Place, Suite 2700, 440 South LaSalle Street, Chicago, IL 60605.

U.S. Bancorp is subject to the informational requirements of the Securities Exchange Act of 1934, as amended, and, in accordance therewith, files reports and other information with the Securities and Exchange Commission (the "SEC"). U.S. Bancorp is not guaranteeing the obligations of USBNA and is not otherwise liable for the obligations of USBNA.

Except for the contents of this section, USBNA and U.S. Bancorp assume no responsibility for the nature, contents, accuracy or completeness of the information set forth in this Commercial Paper Offering Memorandum.