414 Nicollet Mall
Minneapolis, MN 55401

April 7, 2014

—Via Electronic Filing—

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: INITIAL FILING
DECOMMISSIONING POLICIES RELATED TO DEPRECIATION
DOCKET NO. E,G999/CI-13-626

Dear Dr. Haar:

Enclosed for filing are the Comments of Northern States Power Company, doing business as Xcel Energy, in response to the Minnesota Public Utilities Commission's March 6, 2014 Notice of Comment Period.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list.

Please contact Amber Hedlund at amber.r.hedlund@xcelenergy.com or (612) 337-2268 if you have any questions regarding this filing.

Sincerely,

/s/

LISA H. PERKETT
DIRECTOR
CAPITAL ASSET ACCOUNTING

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF A COMMISSION INQUIRY INTO DECOMMISSIONING POLICIES RELATED TO DEPRECIATION

DOCKET NO. E,G999/CI-13-626

INITIAL FILING

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this filing in response to the Commission's March 6, 2014 Notice regarding utility decommissioning and depreciation policies and practices. Below we provide the specific information requested by the Commission and address certain topics identified in the Notice as open for comment.

The information requested and questions asked in the Notice focus on the use of decommissioning probabilities in calculating depreciation expense. Xcel Energy has used decommissioning probabilities to calculate net salvage rates since 1983, as approved by the Commission. We believe use of probabilities is consistent with straight-line depreciation requirements in Minnesota, and does not conflict with the process of setting remaining lives for facilities. However, use of probabilities is not required, and there are other methods under which a utility would recover all decommissioning costs. While the Commission has discretion to allow the use of probabilities, we believe these probabilities appropriately smooth recovery of costs over the life of a plant. In this filing, we discuss in detail how use of probabilities accounts for uncertainty related to estimating the life of a plant and future decommissioning costs, and as such, helps ensure removal costs are spread equitably to all customers over the life of a plant.

REQUESTED INFORMATION

1. *Provide an explanation of your company's plant decommissioning policies including the relationship of the policy to your company's depreciation expense and the calculation of the salvage portion of the depreciation expense.*

Our plant decommissioning policy primarily focuses on business activities surrounding the decommissioning of the plant that should be recorded in Removal Work in Progress (RWIP). The policy governs estimation of final removal costs for inclusion in depreciation expense and establishes accounting requirements for the preparation, dismantling, and disposal costs after the final retirement of a facility. Our policy primarily focuses on capital removal activities for our non-nuclear energy supply facilities. The decommissioning activities included in the cost estimate at a minimum include the plant lay up preparing the site for the work, environmental remediation and abatement where necessary, salvage or scrap recovery, demolition, and site restoration.

The process we use to determine the net salvage rate for each generating unit is not defined in a formal Company policy. Our process starts with the cost estimate established according to the decommissioning policy described above. We then evaluate the station or unit to determine if a decommissioning probability is applicable and adjust the cost estimate as necessary. We calculate the ratio of the cost estimate, as adjusted, to the original cost of the plant to arrive at the net salvage percent. This net salvage percentage then is used in calculating depreciation expense for a unit. Below we discuss each of the four steps in this process.

a) Decommissioning Cost Estimates

Every five years the Company contracts with an engineering firm familiar with decommissioning generation facilities to provide current cost estimates for the NSP-Minnesota fleet, excluding our nuclear plants. (Nuclear decommissioning is reviewed every three years under a separate process.) The cost estimates are done with the assumption that they will be used for setting the proposed net salvage rate and are not intended to be the final detailed decommissioning plan that a demolition contractor will use to actually perform the work. Our last detailed decommissioning cost estimate review was part of our 2010 Annual Review of Remaining Lives (Docket No. E,G002/D-10-173). Our next detailed review will be filed with our February 2015 Remaining Lives filing.

The cost estimation process looks at the current fleet by functional class and groups the units by similar size and fuel type. We do not request detailed cost estimates for individual units except in cases where specific circumstances warrant the additional cost necessary to conduct a unit-specific analysis. Generally, determining cost estimates by group is appropriate because many of the units have longer remaining lives, with final decommissioning that will not happen until well into the future. As such, the final costs incurred will likely deviate from the estimate. In these cases, specificity by individual unit may not provide any additional certainty related to decommissioning costs.

As an example, there are eight gas turbines of 160 MW or more on the NSP-Minnesota system. Because decommissioning costs for a large gas turbine at one site should closely align with the costs to remove a gas turbine at another site, a detailed analysis is conducted for a representative unit. This detailed cost estimate is then applied to the other units in the group, with some scaling of costs to account for output capacity, number of units at a site, and whether there is a steam turbine (the site is a combine cycle site).

The process is used for units that are like kind in layout, in the early part of their lives, and do not have any unique circumstances that would skew the scaling process. For units that are close to final retirement or have unique removal or remediation issues due to location, site conditions, or other requirements, we request specific detailed cost estimates.

The Company also requires the decommissioning cost estimate to include the total station removal estimate because a site with multiple units will have common costs that will need to be accounted for. Finally, unless known otherwise, the cost estimates provided assume the following:

- All units retire at the same time.
- Brownfield removal, minimal feet below ground with the site remaining industrial in nature.
- Entire site shown in analysis regardless of the FERC functional class (one site with steam and other production units).
- Current year dollars, no cost inflation from current year to the year the work is done.
- Decommissioning immediately follows shutdown.
- Substation or transmission equipment at the site is not included.
- All equipment is 40 years or older and thus is not reusable.
- All remaining fuel or fluids that can be used in another facility have been removed from the site.
- All buildings are removed upon retirement of the station.

- Retirement date is the assumed to be the end of the year that the remaining life expires.

The decommissioning cost estimate study conducted every five years is important to ensure recovery is on track to accumulate appropriate decommissioning costs by the end of the unit's useful life. However, many of the assumptions can change when the decommissioning is actually done. Any deviations from the above assumptions are factored into the estimate only when known and if the fact is a significant driver to the cost estimate.

b) Decommissioning Probabilities

The next step in the process is to factor into the cost estimate any applicable decommissioning probability. As discussed in detail in Part 2 below, we believe use of probabilities provides a better smoothing of decommissioning costs over the useful life of the plant. Application of a decommissioning probability accounts for assumptions that the current remaining life may be extended in the future if major maintenance or capital work is identified and determined to be cost effective. Once a probability is defined for use for a specific unit or station, an adjusted decommissioning cost estimate is calculated by multiplying the decommissioning cost estimate by that probability.

c) Net Salvage Rate Calculation

The adjusted cost estimate is then factored into the net salvage rate. To arrive at the proposed net salvage rate, we divide the adjusted cost estimate by the current original cost of the station or unit. For example, a plant that has an estimated cost of removal of $200,000, a decommissioning probability of 50%, and a plant balance of $1,000,000 would have a net salvage percentage of -10%:

($200,000 x 50%) / $1,000,000) = 10%

d) Depreciation Expense Calculation

Finally, we use the net salvage rate as a part of our remaining life depreciation calculation to recover the decommissioning costs over the remaining life of the plant. Depreciation expense is calculated by taking the original cost adjusted for future net salvage costs (multiplying the original cost by one minus the net salvage rate), reducing this amount by the depreciation reserve to date, and dividing the net value by the remaining life.

2. *Provide a detailed explanation of how your company's decommissioning probabilities are determined.*

To help ensure we effectively spread the cost of removal equitably to all customers, we use decommissioning probabilities based on where a plant is in its total expected life span. As a plant moves through its life, a larger percentage the of removal costs estimate is used because the timing and actual costs of decommissioning are more certain. While use of probabilities reduces the current decommissioning cost estimates for some plants, we believe this method appropriately smoothes decommissioning costs over the life of the plant.

The Company has been using a probability with decommissioning estimation since 1983, as approved by the Commission and as discussed further in Part 5 below. In our 2010 Review of Remaining Lives, we proposed and the Commission approved the following revisions to the probability set forth in 1983:

- If the unit has a remaining life less than ten years, we use 100 percent of the cost study's estimate to calculate the net salvage rate.
- If the unit has a remaining life greater than or equal to ten years, but less than twenty years, we use 75 percent of the cost study's estimate to calculate the net salvage rate.
- If the unit has a remaining life greater than or equal to twenty years, we use 50 percent of the cost study's estimate to calculate the net salvage rate.

When a unit is placed in service, the Company proposes a remaining life based on the characteristics of the equipment in its current state without factoring in any major overhauls or rebuilds that may occur in the future, and which may result in an extension of the original remaining life. Setting the remaining life on the current expected whole life assures that the costs will be recovered over that current period should it not be cost effective to extend the usefulness of the unit. However, assuming recovery of 100 percent of the removal cost estimate over the initial remaining life of the plant does not account for the fact that the life of the plant may be extended. We believe using probabilities effectively scales the decommissioning cost estimate to prevent customers in the early years of the plant's life from paying more than their share of the final removal costs.

In addition, the Company uses probabilities because the longer the remaining life of a facility, the more uncertainty there is around the future cost of removal and the timing of the final removal. The timing of the final removal is assumed to be when the asset retires, but that may not be when it occurs. If multiple units exist at the station, the earlier installed units may retire before the last one retires and the asset may be retired in-place waiting many years before the asset is removed.

We believe our decommissioning probabilities are appropriate because the closer a facility comes to the end of its useful life, the greater the need for the Company to recover its full costs, especially if there are no immediate plans to rebuild or reuse the facility. The Company uses probabilities based on the remaining life of the plant, with some exceptions, to determine what portion of the decommissioning cost estimate to use to calculate a net salvage rate.

We do deviate from using the general decommissioning probabilities in certain cases. For example, for the Allen S. King plant and Nobles wind facility, we use 100 percent of the dismantling cost study estimate to calculate a net salvage rate due to circumstances specific to these facilities. There is an expectation that the King plant will be completely dismantled at the end of its productive life due to the plant's proximity to a national waterway. For Nobles, the easement agreement for the land for the Nobles facility requires that complete dismantlement and land restoration must take place at the end of production for the location. In these situations, the generic decommissioning probabilities are not appropriate because there is more certainty that complete dismantlement will be required at each of these locations.

Finally, we note that if the calculation of a net salvage rate using 100 percent of the dismantling cost study estimate results in a net salvage rate between zero and negative five percent, we do not apply a lower decommissioning probability. In these cases, using a lower decommissioning probability would not have a significant impact to depreciation expense.

3. *Explain the relationship between the decommissioning probability and the established life for the plant.*

The approved remaining life of the plant is a key driver in the criteria the Company uses for decommissioning probabilities, as discussed in Part 2 above.

We provide here an example of how using decommissioning probabilities effectively smoothes costs over the life of a plant. In Attachment A, we provide an example of a new unit that starts with a whole life expectation of 35 years. After 20 years of life, major work is completed on the unit, and the remaining life is extended 10 years making the new whole life 45 years. After 35 years, additional work is been completed, and the remaining life is extended 15 more years, resulting in a whole life of 60 years.

If 100 percent of the cost of removal were recovered over the first assumed whole life, two-thirds of the cost would be recovered in the first 20 years, before the first life extension. Continuing without factoring in any probabilities, after the life extension at 20 years, costs charged to customers would be reduced, and after the life extension at 35 years, costs would be even more significantly reduced. Attachment A shows cost recovery both with and without the use of probabilities. As shown, the use of probabilities smoothes the recovery over the life of the plant, consistent with the goal of straight-line depreciation. Attachment A provides an example of cost recovery using probabilities that works perfectly and is meant to be illustrative. While recovery does not in reality work perfectly, we believe using probabilities is smoother over the total life compared to not using probabilities.

4. *Does your company use decommissioning probability in any other jurisdiction in which you operate?*

Yes, the Company uses the same decommissioning probability matrix for all jurisdictions served by NSP-Minnesota, which includes North Dakota and South Dakota. We do not use probabilities in our depreciation studies for Public Service Company of Colorado because the Colorado Public Utilities Commission sets the first whole life with the assumption that the work will be done to achieve the multiple extensions. In other words, the CPUC could likely set the whole life in the example in Attachment A at 60 years when the new unit was first placed in service. Thus, the longer expectation of whole life eliminates the need for the probabilities.

Under either the Colorado or Minnesota method, there is the possibility that removal costs will be under-recovered at the end of the plant's life. This situation has occurred when Colorado required early retirement of some of the smaller coal facilities leaving the removal costs under-recovered. For these assets, the Colorado Commission allowed recovery of the remaining removal costs for a period after the asset has been retired. In Minnesota, in specific instances where it has been determined a life extension for a plant is not cost effective, or removal costs are higher than estimated, the Commission has remedied this situation through either a reserve reallocation (for example the Minnesota Valley plant) or through an amortization of costs after the asset is retired (for example Black Dog Units 3&4).

For Northern States Power Company – Wisconsin, we do not use decommissioning probabilities but are in the process to update the net salvage rates based on engineering studies in 2015. For Southwestern Public Service, the net salvage rates for generation are based on Commission standards rather than specific studies, thus we do not develop specific removal cost estimates or apply probabilities.

5. *Provide any documentation on depreciation practices that provides support for the use of decommissioning probabilities.*

We are not aware of any specific documentation on general depreciation practices and the use of decommissioning probabilities. However, we believe use of these probabilities is justified and meets all Commission rules for depreciation. Minn. Rule 7825.0800 requires the use of the straight-line depreciation method for depreciation, but prescribes no specific methods in determining net salvage values.

The goal of straight-line depreciation is to spread the cost of depreciation uniformly over the remaining life of the plant. The straight-line method does not mean that depreciation expense will be the same every year over the entire life of the asset. Rather, it means that the depreciation expense will be level from the current time forward if no factors used to calculate the expense change over the remaining life. Remaining life assumptions, calculated net salvage rates, and plant balances can be revised over time and cause changes in depreciation under the straight-line method.

The Commission approved the use of decommissioning probabilities in our 1983 Annual Review of Remaining Lives (Docket No. G,E002/D-83-545). In that docket, the Department of Public Service recommended and the Commission approved that Company begin recovering 50 percent of the estimated demolition costs. The rationale was provided in the Department's Comments:

> The DPS cannot state with certainty that the 5 steam plants will not need to be dismantled or demolished at final retirement. Neither can NSP state with certainty that these plants will be demolished. Whether or not plants will be demolished at or after final retirement depends on a number of factors such as demand for power, physical plant condition, rebuilding costs, new plant costs and future legal and environmental requirements. These factors are not known at this time. Therefore, DPS believes it is reasonable to allow partial recovery of the estimated decommissioning costs to begin now so that if demolition is necessary, the entire burden of that cost will not be placed on future ratepayers. On the other hand, if demolition is not required, current ratepayers will not have been burdened for the full cost of demolition which did not occur. As time goes on, we will learn more about the costs and the need for power plant demolition. Cost recovery can then be increased or decreased accordingly.

In our 2010 Remaining Lives proceeding, the Commission approved our revised probabilities, as presented in Part 2 above. The Company specified a routine we follow to calculate and propose new net salvage rates, using the approved decommissioning probability criteria.

COMMENTS

1. *Minn. Rule 7825.0800 prescribes the straight-line method for calculating depreciation. Is the practice of a utility periodically adjusting its decommissioning cost accruals based on the probability of decommissioning occurring at the end of projected life consistent with this rule?*

Yes. As discussed above and shown in our example in Attachment A, we believe use of decommissioning probabilities helps ensure level recovery over the entire life of the asset. The straight-line method for calculating depreciation does allow for depreciation expense to change as additional information is known, whether that is a change in plant balance, assumptions about remaining life, or removal cost estimates that factor into the net salvage rate. We believe changing the decommissioning probability based on the changing remaining life preserves the straight-line method of depreciation.

2. *Is there a dichotomy between setting a proposed life for plant and then determining there is only some percentage (such as 50%) chance of the plant being retired at the end of that life?*

No. We do not believe setting a remaining life but collecting only some portion of the initially estimated decommissioning costs creates any inconsistencies. Until a plant is retired, there is always some probability that the estimated life will not be the actual life. The Company sets remaining lives based on current conditions of plants and definite future plans for operations for the plant. Thus depreciation life is an estimate based on facts known when the estimate is developed. As discussed earlier, setting a remaining life to cover the current expectations of usefulness given the current operating conditions without factoring in the uncertainties of substantial future work, builds in some inherent expectation that the life may be changed once that work is accomplished.

For depreciation purposes, cost recovery can be viewed as two components: the recovery of the original cost and the recovery of the decommissioning costs or final removal costs. Commission rules require straight-line depreciation, that is, costs being evenly spread to all customers receiving benefit from the asset. The remaining life method achieves that requirement by evenly spreading the remaining original cost plus removal over the remaining period. When the life is extended, the old investment is retired and the new investment is added. The use of a shorter remaining life in the early period effectively recovers the investment that was retired from the customers during that period and will recover the new investment from the future customers.

In Attachment B we provide an example showing the original cost recovery with the remaining life changing in the same fashion it did in the removal example in Attachment A. In a perfect scenario, the depreciation will remain level throughout the entire life. Retirements do not change the expense calculation, but the additions increase the expense whereas the life extension decreases it.

As shown in Attachments A and B, the theory creates level depreciation expense for both the removal and the original cost. The calculation for removal works with the use of probabilities, and the calculation for original cost works without the use of probabilities. We do not believe there is a dichotomy between these two recoveries.

3. *Is it appropriate to adjust the amortization of the decommissioning costs to reflect this uncertainty in remaining life calculations?*

We assume this question refers to the component of the depreciation expense for removal recovery. Adjusting net salvage rates to account for uncertainty in final removal date is appropriate because the remaining life is in itself an estimate. The precise retirement date for an asset is not firmly known when it is first placed in service, and most of our current production facilities have had their lives extended at least once during their total life span after significant work has been completed. The decommissioning probabilities allow for this uncertainty in total life while effectively balancing the recovery to all customers throughout the entire life of the unit.

4. *If so, is the frequency or size of the adjustment relevant to the determination of whether the adjustments are appropriate?*

We believe the decommissioning probabilities in our 2010 Remaining Lives filing provides a reasonable match between the decommissioning probabilities and the expected change in remaining life over the total life of the plant.

5. *Are the reasons for using a probability of decommissioning still valid today?*

Yes. We believe the use of probabilities to account for uncertainty in plant decommissioning costs is valid today for all reasons discussed in this filing. There is uncertainty related to both estimating the life of a plant and estimating the costs of future decommissioning. The use of probabilities can prevent over-recovery of decommissioning costs early in the life of the plant and help ensure customers today are not paying more than their portion of the total cost of decommissioning compared to customers in the future.

CONCLUSION

We appreciate the opportunity to provide this information on our decommissioning and depreciation policies and procedures. We look forward to working with the Commission and other parties as this issue is further explored in this proceeding.

Dated: April 7, 2014

Northern States Power Company

Respectfully submitted by:

/S/

LISA H. PERKETT
DIRECTOR
CAPITAL ASSET ACCOUNTING

	Removal Recovery without Probabilities	Removal Recovery with Probabilities
Removal Cost Estimate	1,000,000	1,000,000
First Whole Life	30	30
Second Whole Life	45	45
Third Whole Life	60	60
First Probability		50%
Second Probability		75%
Third Probability		100%
1	33,333	16,667
2	33,333	16,667
3	33,333	16,667
4	33,333	16,667
5	33,333	16,667
6	33,333	16,667
7	33,333	16,667
8	33,333	16,667
9	33,333	16,667
10	33,333	16,667
11	33,333	16,667
12	33,333	16,667
13	33,333	16,667
14	33,333	16,667
15	33,333	16,667
16	33,333	16,667
17	33,333	16,667
18	33,333	16,667
19	33,333	16,667
20	33,333	16,667
21	13,333	16,667
22	13,333	16,667
23	13,333	16,667
24	13,333	16,667
25	13,333	16,667
26	13,333	16,667
27	13,333	16,667
28	13,333	16,667
29	13,333	16,667
30	13,333	16,667
31	13,333	16,667
32	13,333	16,667
33	13,333	16,667
34	13,333	16,667
35	13,333	16,667
36	5,333	16,667
37	5,333	16,667
38	5,333	16,667
39	5,333	16,667
40	5,333	16,667
41	5,333	16,667
42	5,333	16,667
43	5,333	16,667
44	5,333	16,667

First remaining life extension - 10 years

Second remaining life extension - 15 years

45	5,333	16,667
46	5,333	16,667
47	5,333	16,667
48	5,333	16,667
49	5,333	16,667
50	5,333	16,667
51	5,333	16,667
52	5,333	16,667
53	5,333	16,667
54	5,333	16,667
55	5,333	16,667
56	5,333	16,667
57	5,333	16,667
58	5,333	16,667
59	5,333	16,667
60	5,333	16,667
	1,000,000	1,000,000

	Additions	(Retirements)	Ending Plant Balance	Remaining Life	Depreciation Expense	Accumulated Depreciation	
First Whole Life				30			
Second Whole Life				45			
Third Whole Life				60			
1	10,000,000	-	10,000,000	30	333,333	333,333	
2	-	-	10,000,000	29	333,333	666,667	
3	-	-	10,000,000	28	333,333	1,000,000	
4	-	-	10,000,000	27	333,333	1,333,333	
5	-	-	10,000,000	26	333,333	1,666,667	
6	-	-	10,000,000	25	333,333	2,000,000	
7	-	-	10,000,000	24	333,333	2,333,333	
8	-	-	10,000,000	23	333,333	2,666,667	
9	-	-	10,000,000	22	333,333	3,000,000	
10	-	-	10,000,000	21	333,333	3,333,333	
11	-	-	10,000,000	20	333,333	3,666,667	
12	-	-	10,000,000	19	333,333	4,000,000	
13	-	-	10,000,000	18	333,333	4,333,333	
14	-	-	10,000,000	17	333,333	4,666,667	
15	-	-	10,000,000	16	333,333	5,000,000	
16	-	-	10,000,000	15	333,333	5,333,333	
17	-	-	10,000,000	14	333,333	5,666,667	
18	-	-	10,000,000	13	333,333	6,000,000	
19	-	-	10,000,000	12	333,333	6,333,333	
20			10,000,000	11	333,333	6,666,667	First remaining life extension - 10 years
21	5,000,000	(2,000,000)	13,000,000	25	333,333	5,000,000	
22	-	-	13,000,000	24	333,333	5,333,333	
23	-	-	13,000,000	23	333,333	5,666,667	
24	-	-	13,000,000	22	333,333	6,000,000	
25	-	-	13,000,000	21	333,333	6,333,333	
26	-	-	13,000,000	20	333,333	6,666,667	
27	-	-	13,000,000	19	333,333	7,000,000	
28	-	-	13,000,000	18	333,333	7,333,333	
29	-	-	13,000,000	17	333,333	7,666,667	
30	-	-	13,000,000	16	333,333	8,000,000	
31	-	-	13,000,000	15	333,333	8,333,333	
32	-	-	13,000,000	14	333,333	8,666,667	
33	-	-	13,000,000	13	333,333	9,000,000	
34	-	-	13,000,000	12	333,333	9,333,333	
35	-	-	13,000,000	11	333,333	9,666,667	Second remaining life extension - 15 years
36	5,000,000	(2,000,000)	16,000,000	25	333,333	8,000,000	
37			16,000,000	24	333,333	8,333,333	
38	-	-	16,000,000	23	333,333	8,666,667	
39	-	-	16,000,000	22	333,333	9,000,000	
40	-	-	16,000,000	21	333,333	9,333,333	
41	-	-	16,000,000	20	333,333	9,666,667	
42	-	-	16,000,000	19	333,333	10,000,000	
43	-	-	16,000,000	18	333,333	10,333,333	
44	-	-	16,000,000	17	333,333	10,666,667	
45	-	-	16,000,000	16	333,333	11,000,000	
46	-	-	16,000,000	15	333,333	11,333,333	
47	-	-	16,000,000	14	333,333	11,666,667	
48	-	-	16,000,000	13	333,333	12,000,000	
49	-	-	16,000,000	12	333,333	12,333,333	
50	-	-	16,000,000	11	333,333	12,666,667	
51	-	-	16,000,000	10	333,333	13,000,000	
52	-	-	16,000,000	9	333,333	13,333,333	
53	-	-	16,000,000	8	333,333	13,666,667	
54	-	-	16,000,000	7	333,333	14,000,000	
55	-	-	16,000,000	6	333,333	14,333,333	
56	-	-	16,000,000	5	333,333	14,666,667	
57	-	-	16,000,000	4	333,333	15,000,000	
58	-	-	16,000,000	3	333,333	15,333,333	
59	-	-	16,000,000	2	333,333	15,666,667	
60	-	-	16,000,000	1	333,333	16,000,000	
	20,000,000	(4,000,000)	795,000,000		20,000,000	16,000,000	

CERTIFICATE OF SERVICE

I, SaGonna Thompson, hereby certify that I have this day served copies or summaries of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States Mail at Minneapolis, Minnesota

xx electronic filing

DOCKET NO. E,G999/CI-13-626

Dated this 7th day of April 2014

/s/

____

SaGonna Thompson
Records Analyst

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