Type of Addition to Rate Base	PTYA to Rate Base (total company $) Application Estimate	Current SPS Request
Production	$18,124,490	$17,052,842
Transmission	$346,311,639	$302,711,217
Distribution	$42,528,763	$37,011,689
General & Intangible (includes software)	$34,687,061	$35,773,276
Total	**$441,651,953**	**$392,549,024**

TIEC's calculations indicate the following:

- The $441,651,953 of rate base PTYAs requested in SPS's Application included 332 rate base additions whose value ranged from less than $14 to over $158 million.[70]
- SPS's March 2015 update no longer listed 135 of those additions, but included 538 additions, of which 341 were not previously identified. The March 2015 update included 93 separate additions to Production Plant, ranging from $28.83 to $1.6 million. On average, the additions for which SPS requested PTYAs comprised 0.028% of SPS's requested rate base.[71]
- For many rate base additions listed in both the Application and the March 2, 2015 filing, the dollar amount of the requested PTYA changed.[72]

The ALJs find TIEC's method of counting to be reasonable. SPS's Application and March 2015 update described each individual item as a separate "addition" to plant in service.[73] SPS argues that TIEC overstates the number of new projects not included in its Application, explaining that comparison to the Parent project codes for the July 1, 2012 to June 30, 2014 period shows there were 25 new Production Plant projects and 41 new transmission projects.[74] The ALJs find that even SPS's method of counting shows that, months after filing the Application, SPS submitted a large number of changes to the rate base additions for which it is requesting PTYAs.

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[70] SPS Ex. 6, Evans direct at 51; TIEC Ex. 7.

[71] *See* TIEC Ex. 7; TIEC Ex. 8 at 3-5; SPS Ex. 6, Evans direct at 52. (Approximately $392 million in total PTYAs/538 individual additions = $728,625. The Test Year rate base was approximately $2.59 billion. $728,625 is approximately .028% of $2.59 billion.)

[72] TIEC Ex. 9.

[73] TIEC Ex. 8 at 3. As Mr. Evans acknowledged, some of the requested PTYAs are less than $10,000. Tr. at 391; *see also* SPS Ex. 11B.

[74] SPS initial brief (RR) at 56-57.

SPS also argues that no party refuted its evidence on attendant impacts, or on the prudence and reasonable cost of its investments and whether the investments are used and useful. SPS states that it accounted for attendant impacts that reasonably follow from its requested PTYAs, *i.e.*: accumulated depreciation; accumulated deferred federal income taxes (ADIT); SPP Schedule 11 expenses and revenues; property taxes; franchise fees; gross margin taxes; deferred tax expense; and updated customer counts and load data to reflect customer growth and load growth as of December 31, 2014.[75]

TIEC responds that if the Intervenors and Staff had conducted attendant-impact, prudence/reasonableness, and used-and-useful analyses for each of the rate base additions for which SPS requests a PTYA, this case might have become the protracted nightmare the Commission sought to avert when it adopted the PTYA rule. The ALJs agree. Contrary to the PTYA rule[76] and Commission procedures intended to facilitate adequate review of a rate application within applicable deadlines,[77] SPS essentially filed with its Application a placeholder PTYA proposal and related cost of service, and months later submitted a substantially changed PTYA proposal and related cost of service. Regarding its final PTYA proposal, SPS did not provide the parties a cost of service quantification of SPS's view of the PTYAs' attendant impacts until its rebuttal case, *after* the last deadline for the Intervenors and Staff to file testimony.[78]

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[75] SPS Ex. 38, Evans rebuttal at 18.

[76] Under the test-year-end CWIP balance requirement, an approved PTYA is set at "the reasonable test year-end CWIP balance." As the ALJs interpret that phrase, the words "reasonable" and "test-year-end CWIP balance" are connected. Using test-year-end CWIP numbers, the utility can file its PTYA proposal (limited in scope to comply with the PTYA rule) and related testimony and cost of service (including attendant impacts) with its application, thus allowing the other parties sufficient time to analyze the proposal's compliance with the PTYA rule requirements.

[77] *See* 16 TAC § 22.225(a)(6)(A): "Any utility filing an application to change its rates in a major rate proceeding shall file the written testimony and exhibits supporting its direct case on the same date that such statement of intent to change its rates is filed with the commission. As set forth in §22.243(b) of this title (relating to Rate Change Proceedings), the prefiled written testimony and exhibits shall be included in the rate filing package filed with the application."

[78] SPS did not obtain the information necessary to update year-end customer and load information until approximately March 22, 2015. SPS Ex. 38, Evans rebuttal at 18-19. SPS provided those numbers in discovery on March 24, 2015, seven weeks before Intervenor direct testimony was due. SPS Ex. 38, Evans rebuttal at 24-25. SPS did not file a cost of service quantification of attendant impacts of its final PTYA proposal until its rebuttal case. Tr. at 333-334; SPS Ex. 53, Blair rebuttal at 30.

As noted earlier, SPS concedes that its proposed rate base PTYAs do not comply with either the 10% requirement or the test-year-end CWIP balance requirement of the PTYA rule. As discussed below, SPS also did not show good cause for its requested exceptions to those rule requirements. For those reasons, and given the problems described above, the ALJs decline to reach the prudence/reasonableness, used-and-useful, and attendant-impacts issues regarding SPS's proposed PTYAs. Determinations on those issues are not necessary to the ALJs' recommendation, would have lasting impacts on SPS's rate base, and should be made in a case that does not present the above problems, which were a direct result of SPS's noncompliance with the PTYA rule.[79] The ALJs recommend rejecting the PTYAs because: (1) they violate the 10% requirement and the test-year-end CWIP balance requirements; and (2) SPS did not show good cause for its requested exceptions from those requirements.

3. Evidence Regarding Good Cause for Exceptions to the PTYA Rule

As noted previously, SPS currently seeks PTYAs for approximately $392.5 million in rate base additions. That is a reduction from the approximately $441.7 million in rate base additions for which SPS requested PTYAs in its direct case.[80] SPS's asserted basis for its requested good cause exceptions is that it is in a heavy construction period and the PTYAs are necessary to its financial integrity. In his direct testimony, SPS witness Mr. Evans summarized SPS's actual and projected capital expenditures by calendar year:[81]

Year	Actual Capital Expenditures	Year	Estimated Capital Expenditures
2008	$193 million	2014	$535 million
2009	$212 million	2015	$570 million
2010	$310 million	2016	$710 million
2011	$310 million	2017	$710 million
2012	$390 million	2019	$595 million
2013	$555 million		

[79] The PFD thus does not summarize the parties' testimony and other evidence regarding the prudence/ reasonableness, used-and-useful, and attendant-impacts issues.

[80] SPS Ex. 6, Evans direct at 51.

[81] SPS Ex. 6, Evans direct at 44.

He stated that SPS expects to more than double its net rate base over the next five years and that the "regulatory lag associated with this significant level of completed construction projects is having an adverse effect on SPS's financial wherewithal" and would place "additional downward pressure on SPS's bond ratings."[82]

In her direct testimony, SPS witness Mary P. Schell provided a table showing SPS's credit ratings from three major credit ratings agencies:[83]

Rating Agency	SPS's Current Corporate Credit Rating	Outlook
Standard & Poors (S&P)	A-	Stable
Moody's Investors Service (Moody's)	Baa1	Stable
Fitch Ratings (Fitch)	BBB	Stable

She stated that if SPS falls to the "Aggressive" category, it is at risk of a rating downgrade by S&P.[84]

In a discovery response, SPS acknowledged: "SPS has not quantified the effect the requested good-cause exception would have on the financial integrity of SPS and Xcel Energy."[85] Ms. Schell agreed that metrics such as return on equity, funds for operations, and debt-to-EBITDA (earnings before interest, taxes, depreciation, and amortization) are important for measuring financial integrity, and that lenders and investors look to those metrics in making investment decisions.[86] In response to discovery, SPS provided a table comparing SPS's financial metrics with and without the PTYAs with SPS's financial metrics for the previous five years, as adjusted to replicate methods employed by S&P:[87]

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[82] SPS Ex. 6, Evans direct at 44, 52-53.

[83] SPS Ex. 8, Schell direct at 23.

[84] SPS Ex. 8, Schell direct at 23-23.

[85] AXM Ex. 5, Carver direct, Att. SSC-6 at Bates 175.

[86] Tr. at 128, 437-438.

[87] OPL Ex. 9A (SPS RFI response, non-confidential portion); Tr. at 445-456.

Financial Metric	**Year End 2010**	**Year End 2011**	**Year End 2012**	**Year End 2013**	**Year End 2014**	**Projected Year End 2015 with PTYAs**	**Projected Year End 2015 without PTYAs**
EBITDA (millions)	$291.7	$311.6	$343.5	$335.8	$405.7	$450.6	$426.8
Funds for Operations/Debt (%)	17.6	20.9	20.6	17.6	25.1	19.4	18.4
Funds for Operations/ Interest (x)	3.5	4.1	4.1	3.8	5.3	4.5	4.4
Debt/EBITDA (x)	3.7	3.6	3.6	3.9	3.6	3.6	3.9
Total Debt/ Total Capital (%)	55.6	53.7	54.3	54.2	51.9	50.0	50.4
Total Equity/ Total Capital (%)	44.4	46.3	45.7	45.8	48.1	50.0	49.6

When asked about the table, Ms. Schell agreed that, even without the PTYAs, SPS projects: (1) an EBITDA for year 2015 that is higher than in any year between 2010 and 2014; (2) a funds for operations/debt ratio that is higher than in any year between 2010 and 2013; (3) a funds for operations/interest ratio that is higher than any year between 2010 and 2013; and (4) a better debt/capital ratio than in any year between 2010 and 2014.[88]

Parties opposing the PTYAs argue that, during the previous five years, SPS had stable and positive credit ratings.[89] Staff witness Anjuli Winker testified that, "[d]espite SPS having record-high capital expenditures, Moody's expects the Company to have improving credit metrics."[90] These parties also argue that, taking into account its most recent base rate increase, SPS's 2014 Earnings Monitoring Report would indicate an earned return on equity of 9.94%.[91]

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[88] Tr. at 444-454; *see also* OPL Ex. 9-A (non-confidential portion). Ms. Schell noted that 2014 had some accounting anomalies due to deferred tax and bonus depreciation metrics that made 2014 metrics "unusually favorable." Tr. at 447-448.

[89] AXM Ex. 4, Parcell direct, Att. DCP-4.

[90] Staff Ex. 6A, Winker direct at 7.

[91] AXM Ex. 27; Tr. at 750-760, 1,431-1,433; *Application of Southwestern Public Service Company for Authority to Change Rates and to Reconcile Fuel and Purchased Power Costs for the Period July 1, 2012 through June 30, 2013*, Docket No. 42004, FFs 15-20 and Ordering Paragraph 1 (Dec. 19, 2014) (approving a base-rate increase of $37 million and allowing SPS to implement a surcharge to recover the charge it would have collected if the approved rates had applied to service rendered from June 1, 2014, through September 30, 2014).

In addition, noting that transmission accounts for most of the cost of the rate base additions for which SPS requests PTYAs, AXM and TIEC argue that as early as January 2014, SPS began receiving payments from other SPP members for 90% of the transmission PTYAs through the SPP Schedule 11 process, with the amount depending on the nature and function of the underlying transmission projects.[92]

In his rebuttal testimony, Mr. Evans testified that, compared to allowing the PTYAs, rejecting the PTYAs would: (1) reduce SPS's realized return on equity by approximately 48 basis points; (2) reduce its net income by approximately $15.5 million; and (3) cause SPS's funds for operations/debt ratio to decline from 19.4% to 18.4%. In his opinion, this would cause SPS to fall from Moody's Single A benchmark to the Baa rating, and push SPS deeper into S&P's "Aggressive" category.[93] In her rebuttal testimony, Ms. Schell cited statements by S&P that SPS's capital spending is ongoing and S&P expects "recovery of these costs to remain mostly supportive," and statements by Fitch that unfavorable regulatory developments "including the inability to timely recover costs associated with SPS'[s] large [capital expenditure] program" would likely lead to a ratings downgrade.[94]

The ALJs conclude that SPS did not show that it needs the PTYAs to maintain its financial integrity.[95] On the contrary, the evidence indicates that the PTYAs have little effect on SPS's key financial metrics. The most recent action taken by rating agencies was an upgrade in early 2014, and SPS is not on credit watch for a downgrade.[96] Moody's appears to expect improving financial metrics and S&P expects recovery of capital spending "to remain mostly supportive." Mr. Evans testified: "The capital markets watch the Commission's decisions very

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[92] Tr. at 286-291; AXM Ex. 5, Carver direct at 18-19. SPS's Schedule 11 expenses and revenues are discussed in Section VIII.H.2 of the PFD.

[93] SPS Ex. 38, Evans rebuttal at 29.

[94] SPS Ex. 39, Schell rebuttal at 33.

[95] This conclusion is supported by the expert opinion of Intervenor and Staff witnesses. *See* AXM Ex. 5, Carver direct at 19; OPL Ex. 1, Griffey direct at 26; OPUC Ex. 1, Ramas direct at 15; Staff Ex. 9A, Cutter direct at 6.

[96] OPL Ex. 1, Griffey direct at 23.

closely, including its decisions regarding regulatory lag."[97] He conceded that "the Commission has historically invoked the 10% requirement fairly consistently without waiver."[98] Based on the clear language and historical application of the PTYA rule, the ALJs consider it likely that non-availability of the PTYAs is already built into the expectations of rating agencies and investors following the issue.

For the reasons discussed above, the ALJs recommend that none of SPS's requested rate base PTYAs be allowed.[99]

B. Prepaid Pension Asset

SPS proposes to include in rate base a prepaid pension asset in the amount of $168,638,622 (total company). According to SPS, that represents the amount by which SPS's cumulative cash contributions to its pension trusts exceed the cumulative pension cost recognized under Statement of Financial Accounting Standard (FAS) 87.[100]

AXM and OPUC oppose SPS's request regarding the prepaid pension asset. AXM argues that the Commission has not yet determined whether SPS's prepaid pension assets should be included in rate base, and making the determination is fact-driven. Thus, whether the Commission has approved other utilities' prepaid pension assets does not bear on the facts of this case, contends AXM.

SPS witness Richard S. Schrubbe provided the following example of how a prepaid pension asset is formed:

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[97] SPS Ex. 38, Evans rebuttal at 23.

[98] Tr. at 127; SPS Ex. 38, Evans rebuttal at 21.

[99] Unless otherwise stated, the PFD does not further discuss flow-through impacts in the event the PTYAs were instead granted.

[100] Mr. Schrubbe testified that, in 2009, FAS 87 was renamed Accounting Standards Codification 715-30, but he (and the parties) still refer to the standard as "FAS 87." SPS Ex. 30, Schrubbe direct at 15.

> [S]uppose that the pension plan has been in existence for five years, and that the contribution to the pension trust for each of five years has been $100, whereas the actuarially determined pension cost in each of those five years has been $90. The table below shows how the excess of contributions each year creates a cumulative prepaid pension asset:
>
> | Year | Pension Contribution | Pension Cost | Cumulative Prepaid Pension Asset |
> |---|---|---|---|
> | 1 | $100 | $90 | $10 |
> | 2 | $100 | $90 | $20 |
> | 3 | $100 | $90 | $30 |
> | 4 | $100 | $90 | $40 |
> | 5 | $100 | $90 | $50 |
>
> At the end of the five year period, the utility has a cumulative pension trust fund balance of $500 and cumulative pension cost of $450, which produces a prepaid pension asset of $50. Of course, the opposite can also occur. If pension costs exceeds the pension contributions in a given year, the prepaid pension asset will decline, or if there is no prepaid pension asset, the utility may have a pension liability. Over the long run, pension contributions and pension cost will equal, but over the short and intermediate run there will be differences, which are recorded as prepaid pension assets or pension liabilities.[101]

Pension costs are determined under FAS 87, Employers' Accounting for Pensions.[102] Although the cost and contribution calculations both use accrual methodologies, the assumptions, attribution methods, and periods of time over which the costs are required to be recognized are different, which can often result in different annual amounts. Federal law prohibits the withdrawal of any amounts from the pension trust fund except for the payment of benefits and plan expenses.[103]

According to Mr. Schrubbe, even though SPS cannot withdraw the prepaid pension asset or otherwise use it, the earnings on the asset are considered utility income that reduces the revenue requirement. Returning to his example, he explained that, if the utility had a revenue

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101 SPS Ex. 30, Schrubbe direct at 48-49.

102 SPS Ex. 30, Schrubbe direct at 15.

103 SPS Ex. 30, Schrubbe direct at 49.

requirement of $300 and it expected to earn a 6% return on the pension fund, the $3 return on the $50 prepaid pension asset (0.06% x $50) would be credited against the revenue requirement (rate base), so that the utility could only collect $297 from its customers through rates. Thus, the revenue requirement is reduced by $3 as a result of the prepaid pension asset. Because SPS cannot withdraw amounts from the trust fund, it must forgo recovering its full cost of service unless the prepaid pension asset is included in rate base.[104]

Mr. Schrubbe testified that SPS's Test Year pension cost is $11,475,595 less on a total company basis because of earnings on the prepaid pension asset. It is as if SPS's pension expense is reduced by $7,584,221 to total company SPS pension expense. Thus, the SPS revenue requirement will be $7,584,221 less for pension expense in the Test Year as a result of the earnings on the prepaid pension asset, and SPS has no way to recover that amount if the prepaid pension asset is not included in rate base. According to Mr. Schrubbe, because the prepaid pension asset is reducing the cost of service for customers, SPS essentially will be giving customers a loan, and it should receive a corresponding return.[105]

If SPS had an unfunded accrued pension cost instead of an prepaid pension asset, Mr. Schrubbe would recommend that the cost be subtracted from rate base. In fact, that is the situation with SPS's non-qualified retirement plan. For that plan, historical pension cost under FAS 87 has exceeded contributions and SPS has a corresponding unfunded pension liability on its balance sheet. SPS has made a corresponding reduction in rate base in this rate case in the amount of $1,780,001 (total company). The net prepaid pension asset, qualified and non-qualified, is $168,638,622 (total company).[106]

Mr. Schrubbe also explained that it does not make a difference whether the prepaid pension asset is made up of SPS contributions or high returns on the market. The asset can also

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104 SPS Ex. 30, Schrubbe direct at 49-50.

105 SPS Ex. 30, Schrubbe direct at 50.

106 SPS Ex. 30, Schrubbe direct at 52-53.

increase because of demographics, different assumptions, or plan changes. But the basis for building the asset and the effect on expense is the same.[107]

OPUC witness Donna Ramas recommended that SPS's request to include the prepaid pension asset in rate base be denied because SPS failed to demonstrate that the balance shown was funded by shareholders, not ratepayers. Similarly, AXM witness Steven C. Carver stated that SPS provided no factual support to quantify the cumulative extent of ratepayer benefits. Mr. Carver suggested that the asset should be included in rate base only if it can be reasonably demonstrated that reduced pension costs, including pension credits, on a cumulative bases, have flowed through to the benefit of the ratepayers in an amount at least equal to the pension asset.[108]

SPS witness Mr. Schrubbe dismissed these witnesses' arguments, claiming they are irrelevant. He reiterated that the purpose of allowing SPS to earn a return on the prepaid pension asset is to make SPS whole for the annual pension cost reduction that will occur during the time the rates set in this case will be in effect, not to make SPS whole for reduced rates in the past.[109] In fact, Mr. Schrubbe indicated that, during the Test Year, the prepaid pension asset reduced total company costs by nearly $11.5 million.[110]

Mr. Carver and Ms. Ramas also testified that a return on the prepaid pension asset is unnecessary because the prepaid pension arose, in part, from negative pension expense, rather than solely by SPS contributions. Mr. Carver explained that for a 13-year period, 1997-2009, SPS had negative pension costs, which in his opinion, illustrates that the pension asset did not arise from actual cash contributions to the pension fund. Except for a negotiated settlement

[107] SPS Ex. 30, Schrubbe direct at 51.

[108] OPUC Ex. 1, Ramas direct at 47; AXM Ex. 5, Carver direct at 64-65.

[109] Mr. Schrubbe clarified that his reference to "the time the rates set in this case will be in effect" does not mean that SPS is seeking to recover amounts incurred or calculated after the Test Year. It is only used to emphasize that the earnings on the prepaid pension asset portion of the pension trusts will have an effect on the rates set in this case, not past rates. SPS Ex. 49, Schrubbe rebuttal at 22.

[110] SPS Ex. 49, Schrubbe rebuttal at 21-22. This amount is not adjusted for tax effects.

resolving an SPS rate case in Docket No. 32766[111] (that Test Year ended September 2005), none of the negative net periodic pension costs were recognized in setting utility rates. According to Mr. Carver, these unique facts and circumstances support the exclusion of the prepaid pension asset from rate base.[112]

Mr. Schrubbe countered this testimony by explaining that the prepaid pension asset is the difference between: (1) SPS's cumulative contributions to the pension trusts, and (2) the cumulative pension cost recognized under FAS 87. The cumulative contribution amount does not change unless SPS makes a contribution to the trust fund (if it does, the cumulative contribution amount grows, and it cannot decline because SPS cannot withdraw money). The cumulative pension cost changes every year, however. In those years in which the annual pension cost is positive, the cumulative recognized pension cost rises, which reduces the prepaid pension asset, absent any contributions from SPS. But when the annual pension cost is negative, the cumulative recognized pension cost amount declines, which increases the amount of the prepaid pension asset.[113]

As explained by Mr. Schrubbe, annual pension cost is calculated as follows:[114]

	Current service cost
+	Interest cost
-	Expected return on assets
+/-	Loss (gain) due to difference between expected and actual experience of plan assets or liabilities from prior periods
<u>+</u>	<u>Amortization of unfunded prior service cost</u>
=	Annual pension cost

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111 *Application of Southwestern Public Service Company for Authority to Change Rates; Reconciliation of its Fuel Costs for 2004 and 2005; Authority to revise the Semi Annual Formulae Originally Approved in Docket No. 27751 Used to Adjust its Fuel Factors; and Related Relie*f, Docket No. 32766 (Jul. 27, 2007).

112 OPUC Ex. 1, Ramas direct at 48; AXM Ex. 5, Carver direct at 56.

113 SPS Ex. 49, Schrubbe rebuttal at 24.

114 SPS Ex. 49, Schrubbe rebuttal at 25.

If the reductions to annual pension cost (*i.e.*, the expected return and gains due to the differences between prior-period assumptions and actual experience) are larger than the three elements of cost, annual pension cost is negative.[115] SPS suggests that AXM and OPUC are confusing cumulative pension contributions and cumulative pension cost. As Mr. Schrubbe testified, the cumulative contribution amount does not change as a result of negative pension expense. Rather, it changes only when SPS makes a contribution to the pension trust fund. Moreover, Mr. Schrubbe stated that customers reap the benefit of a negative expense because it remains in the pension trust and customers earn a return on it.[116] He provided another example:

> [S]uppose that in a given year the combination of the service cost, the interest cost, and the amortization of unfunded prior service cost was $20 million, whereas the combination of the [expected return on assets] and the prior-period gains was $30 million. Absent the [Employee Retirement Income Security Act] prohibition on withdrawing amounts from a qualified pension trust, SPS could take the excess $10 million and use it for operating expenses or recognize it as earnings, given that it is not needed to satisfy the pension benefit obligations. But because federal law does not allow SPS to withdraw the $10 million, those dollars stay in the pension trust. Thereafter, customers earn a return on the $10 million, and that return is used to lower annual pension cost, even though customers have not yet paid the $10 million through recognized annual pension cost.[117]

While Mr. Carver and Ms. Ramas provided a number of scenarios to support their opinions in this case, Mr. Schrubbe effectively rebutted them.[118] Mr. Schrubbe, however, cited to Commission precedent for his opinion that:

1. Negative pension expense does not indicate that customers made some of the prepaid pension asset contributions. Docket Nos. 40443 and 33309.

2. A utility must show customers benefited in prior years through lower rates as a result of the prepaid pension asset. Docket No. 40443.

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115 Prior-period gains may result from higher-than-expected market returns, but they can also result from liability gains. Liability gains occur when the pension benefit obligation declines for reasons such an increase in the discount rate or mortality changes. SPS Ex. 49, Schrubbe direct 49 at 25.

116 SPS Ex. 49, Schrubbe rebuttal at 24-25.

117 SPS Ex. 49, Schrubbe rebuttal at 26-27.

118 *See* SPS Ex. 49, Schrubbe rebuttal at 29-36.

OPUC and AXM fail to explain why their arguments concerning prepaid assets should be adopted despite Commission precedent. AXM's argument that the facts are different in this case was not supported by evidence or argument. While the ALJs recognize that this is the first time SPS seeks to place its prepaid pension asset into rate base, Mr. Schrubbe's explanation as to the rationale for its inclusion comports with PURA and Commission precedent.[119] The prepaid pension asset benefits SPS customers because it generates a return that is used to reduce annual pension cost. The ALJs recommend the inclusion of SPS's prepaid pension asset into rate base as requested.

With this recommendation, the ALJs turn to AXM's proposal to reduce the amount of the prepaid asset, as recommended by Mr. Carver. Mr. Carver suggested that the Commission use SPS's lower pension asset balance as of December 31, 2014, which is $153.7 million, rather than SPS's average Test Year balance of $168.6 million (both, net of related ADIT reserves). In response, Mr. Schrubbe stated that SPS's prepaid pension asset balance typically varies over the course of the year. However, because prepaid contributions are made in January, the asset is highest then and decreases each month as the pension expense is recognized. SPS used a 13-month average that encompassed the Test Year to achieve a representative amount for the asset. However, Mr. Carver chose an amount for six months after the end of the Test Year.

The ALJs do not adopt Mr. Carver's recommendation. Mr. Carver's suggestion is a PTYA and one that, according to Mr. Schrubbe, includes lower balances at the end of the year. It is more reasonable to use a 13-month average encompassing the Test Year.

If the Commission does not exclude the prepaid pension asset from rate base, OPUC witness Ms. Ramas recommended that the Commission require SPS to use a tracking mechanism. She believes that the prepaid asset should be considered on a prospective basis only, and SPS should be required to track the difference between the amount of cash funding into

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119 *E.g.*, Docket No. 40443, Order on Rehearing at FF 135; Docket No. 39896, Order on Rehearing at FF 28; *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 33309, Order on Rehearing at 6 (Mar. 4, 2008).

the pension and other post-employment benefit (OPEB) plans and the amount of pension costs factored into revenue requirements that are collected from customers.[120]

SPS strongly opposes this recommendation. Mr. Schrubbe testified that Texas law already provides for a tracker to ensure that the amount of annual pension cost included in rates is ultimately trued up to the actuarially determined annual pension cost. He also noted that Ms. Ramas's proposal would pretend that the existing prepaid pension asset does not exist.[121] The ALJs find that Ms. Ramas's recommendation is not well-supported or necessary.

C. FAS 106 and FAS 112 Liabilities

SPS included in rate base its accrued liabilities under FAS 106, which governs retiree medical expense, and FAS 112, which governs long-term disability. Those liabilities, which total $17,391,011 for FAS 106 and $2,341,289 (total company) for FAS 112, reduce SPS's rate base by $19,732,300.[122]

Consistent with their positions that the prepaid pension asset should not be included in rate base, AXM and OPUC witnesses recommended elimination of the medical expense and long-term disability liabilities from rate base.[123] For the same reasons the ALJs recommend the prepaid pension asset be included in rate base, these liabilities should also be included.

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[120] OPUC Ex. 1, Ramas direct at 51-52.

[121] SPS Ex. 39, Schrubbe rebuttal at 38-39.

[122] SPS Ex. 37, Blair direct at 33.

[123] AXM Ex. 5, Carver direct at 77-78; OPUC Ex. 1, Ramas direct at 52. Ms. Ramas only mentioned removal of the FAS 106 liability.

D. Cash Working Capital

An allowance for cash working capital may be included in a utility's rate base.[124] As SPS witness Ms. Blair explained,[125] to support its requested cash working capital allowance, SPS presented a lead-lag study, which measures the difference between two time periods:

- *the expense lead*: the period between the date SPS receives goods or services (incurs expenses) and the date those expenses are paid; and
- *the revenue lag*: the period between the midpoint of the service period and the date SPS receives payment from the customer.

The difference between those items (a net number of days) is divided by 365 days to produce the cash working capital factor, which is multiplied by the corresponding Test Year expense items. The result is an addition to rate base if positive and a subtraction from rate base if negative. A negative cash working capital factor indicates that SPS receives revenue before it pays expenses.

The only challenge to SPS's requested cash working capital is AXM's proposed adjustment relating to federal income tax expense lag.[126] For reasons discussed below, the ALJs recommend rejecting AXM's adjustment.

According to SPS witness Ms. Blair, during the Test Year SPS had a federal income tax net operating loss, mainly due to the availability of bonus depreciation during that time. Bonus tax depreciation results in more income tax deductions than net income, causing a tax net operating loss, which is shown as negative federal taxable income and then used to calculate federal income tax expense. Consistent with its treatment of other cash working capital items,

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[124] 16 TAC § 25.231(c)(2)(B)(iii); *see also State v. Pub. Util. Comm'n*, 450 S.W.3d 615, 636 (Tex. App.—Austin 2014, pet. filed).

[125] SPS Ex. 37, Blair direct at 34-35.

[126] As discussed later in this PFD, the ALJs agree with the uncontested recommendation of Staff witness Anna Givens to reclassify the Commission assessment tax (PUC assessment tax) from FERC Account 928 to FERC Account 408. That change will have a flow-through impact on the cash working capital calculation. Staff Ex. 5A, Givens direct at 38–40.

SPS multiplied the federal income tax expense by the cash working capital factor for federal income tax expense. SPS's lead-lag study calculated an expense lead of 37.25 days and a revenue lag of 35.83 days, producing a negative net lag of 1.42 days and a federal income tax cash working capital factor of (.003890). Multiplying the negative cash working capital factor by the negative federal income tax expense produced a positive result.[127]

AXM witness James R. Dittmer objected that SPS is requesting a negative cash working capital balance for federal income taxes, even though SPS is not receiving any refunds for those taxes. He concluded that SPS is accruing net operating losses that have no cash impact but calculating cash working capital as though they were cash events. He proposed setting the cash working capital balance at zero when both the amount and the factor are negative.[128]

As explained by Ms. Blair, the cash working capital calculation includes a number of expense accounts with negative balances. Several are shown as separate lines in SPS's rebuttal cost of service. Others are included in the expense account balances in SPS's rebuttal cost of service but not shown as separate lines. Making an adjustment to remove the negative expense balances from the cash working capital calculation would increase rate base, because many of the negative expenses are fuel and O&M expenses with a positive cash working capital factor. In her opinion, cash working capital should be calculated as SPS did, by multiplying the cash working capital factor by the various expense accounts without making adjustments for negative expense amounts.[129]

AXM argues that, in the examples in which SPS applied a payment lag to negative expenses, line-item negative expense amounts are consolidated with much larger amounts of positive cash values to arrive at an average payment lag, which is applied to net expenses in a given category. For negative current income taxes, the entire expense line item is negative current income tax expense, for which no payment lag could exist.

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[127] SPS Ex. 53, Blair rebuttal at 36-37.

[128] AXM Ex. 2, Dittmer direct at 31.

[129] SPS Ex. 53, Blair rebuttal at 37-38, Att. DAB-RR-R2 at 12-19.

The ALJs are not persuaded that setting the cash working capital balance at zero whenever both the amount and the factor are negative, as Mr. Dittmer proposed, would produce an accurate result. Ms. Blair demonstrated that Mr. Dittmer's adjustment would be inconsistent with the methodology used in the rest of SPS's lead-lag study. As noted above, no party objected to any other aspect of SPS's requested cash working capital. The ALJs recommend rejecting Mr. Dittmer's adjustment.

E. Accumulated Deferred Federal Income Taxes

As explained by SPS witness Ms. Blair and AXM witness Mike Brosch,[130] book/tax differences are caused by differences in accounting requirements under Generally Accepted Accounting Principles (GAAP)[131] versus under the Internal Revenue Code. Many book/tax differences are temporary because they arise from timing differences, *i.e.* a specific cost is deductible for tax purposes in a different year than for book (financial accounting) purposes. GAAP requires recognition of income tax impacts from these book/tax timing differences by recording ADIT assets or liabilities.

SPS calculated a net ADIT liability balance of $805,442,529 (total company), which is the net of the deferred tax assets (FERC Account 190) and the deferred tax liabilities (FERC Accounts 281, 282, and 283).[132] AXM and OPUC recommend reducing that balance by removing two deferred tax assets: bad debt reserve accruals ($1,937,647), and vacation accrual reserves ($1,684,799).[133] Finding that, for reasons described below, SPS did not meet its burden of proof, the ALJs recommend excluding both deferred tax assets from rate base.

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130 SPS Ex. 37, Blair direct at 28-29; AXM Ex. 1, Brosch direct at 17-19.

131 GAAP Accounting for Income Taxes is set forth in the Financial Accounting Standards Board's Accounting Standards Codification 740. AXM Ex. 1, Brosch direct at 18, n. 20.

132 SPS Ex. 53, Blair rebuttal, Att. DAB-RR-R2 at 9-11.

133 AXM Ex. 1, Brosch direct at 20-21; OPUC Ex. 1, Ramas direct at 41-42, 79, Errata to Exh. DR-3, Sch. 11; *see also* SPS Ex. 37, Blair direct at 30; SPS Ex. 53, Blair direct, Att. DAB-RR-2 at 9, line 212, and 10, line 250.

1. Obligation to Include Offsetting Adjustments to Rate Base

AXM witness Mr. Brosch and OPUC witness Ms. Ramas objected that including bad debt reserve accruals and vacation accrual reserves in rate base would be unreasonable and inconsistent, because SPS did not also reduce rate base by including the corresponding asset or liability balance recorded on SPS's balance sheet, *i.e.*, the reserve for uncollectible accounts and SPS's accrued liability to recognize employee vacations earned but not yet taken.[134] Ms. Ramas opined that as a general principle, deferred tax assets "should be treated consistently with the underlying liabilities that generated the deferred tax."[135] Mr. Brosch stated that ADIT balances are a form of zero-cost capital to the utility and that regulators normally include ADIT balances as a reduction to rate base in order to properly quantify the *net* amount of investor-supplied capital to support rate base assets.[136]

In post-hearing briefing, SPS argues that Mr. Brosch and Ms. Ramas did not identify any support for their position that an ADIT balance associated with a deferred tax asset must have a corresponding liability included in rate base. SPS cites a recent case in which, in response to a similar argument, the Austin Court of Appeals observed: "Steering Committee has not identified a statute, regulation, or evidence supporting its argument on appeal that Oncor's computation of its ADIT assets for pensions was flawed because of a failure to 'counter-balance' pension assets with liabilities reflecting the 'timing differences' Steering Committee asserts in its appellate briefs."[137]

The ALJs find SPS's argument unconvincing. SPS witness Ms. Blair testified: "SPS has consistently applied the principle that elements of cost included in rate base should be included in ADIT, and elements of cost that are not included in rate base should be excluded from

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134 AXM Ex. 1, Brosch direct at 20-22; OPUC Ex. 1, Ramas direct at 41-42.

135 OPUC Ex. 1, Ramas direct at 41.

136 AXM Ex. 1, Brosch direct at 19.

137 *State v. Pub. Util. Comm'n*, 450 S.W.3d at 644.

ADIT."[138] She stated that she eliminated from ADIT "all balances that are related to items not included in the cost of service," explaining that "[b]ecause the costs that generated these deferred taxes are not part of the cost of service, the associated deferred tax balances must be excluded as well."[139] Based on her testimony and that of Mr. Brosch and Ms. Ramas, the ALJs conclude that, for the deferred tax assets relating to bad debt and vacation accruals to be included in rate base, SPS's burden of proof includes showing that it appropriately included the corresponding asset or liability on SPS's balance sheet.

2. Offsetting Rate Base Adjustments in Cash Working Capital

According to Ms. Blair, SPS included the underlying bad debt reserve in rate base, through its calculation of cash working capital. She explained that the reserve for bad debts is an offset to accounts receivable, which is a component of cash working capital rather than an item directly included in rate base. The revenue lag component of SPS's lead lag study quantifies the amount of working capital associated with accounts receivable. The faster customers pay their bills, the lower the revenue lag and, thus, the working capital requirements. For book purposes, SPS includes its bad debt reserve in the revenue lag component of cash working capital until the account age reaches approximately 180 days. When the account reaches 180 days, it is written off and is deductible for tax purposes. But for every day up to the 180th day, a revenue lag exists, the cash working capital requirement grows larger, and SPS's shareholders must supply the working capital. On the tax side of the book/tax timing difference, SPS deducts the difference between the amount it accrues each month for bad debt and the amount it writes off. Ms. Blair concluded that AXM and OPUC are the parties requesting asymmetrical treatment, because they seek to exclude bad debt ADIT from rate base while bad debt reserve reduces the accounts receivable amount included in cash working capital.[140]

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138 SPS Ex. 53, Blair rebuttal at 32.

139 SPS Ex. 37, Blair direct at 32.

140 SPS Ex. 53, Blair rebuttal at 33-35.

Similarly, Ms. Blair testified that regular payroll is included in the cash working capital calculation, which includes payments for vacation pay. Employees generally take vacation after it has been earned, although SPS policy allows employees to take vacation before it is earned. This is all reflected in the regular payroll included in the Total O&M Expense component of cash working capital.[141]

Mr. Brosch disputed SPS's claim that its lead-lag study accomplishes the inclusion of the reserve/liability balances associated with bad debts and vacation accruals. Regarding bad debts, he cited an SPS discovery response that states:

> The sampling process selects customer bills that have outstanding balances of varying ages. When a bill has been outstanding for 180 days, it becomes an uncollectible expense. To the extent that more customers' bills are being paid later, the revenue lag factor increases, resulting in a larger working capital requirement. As more customers reach the 180-days point, SPS incurs more uncollectible expense, which translates into a higher uncollectible reserve.[142]

Mr. Brosch testified that if a lead-lag study determines revenue lag by sampling analysis of when its customers actually pay their bills, the study is not affected by customers' bills that remain unpaid and ultimately become bad debts. He also cited an SPS discovery response stating that: "The revenue lag is not affected by the uncollectible accounts or by the timing of customer non-payments for bad debts because the accounts that remain unpaid after 180 days are not considered in the revenue calculation."[143] Asked whether SPS contends that its cash working capital study measures any specific cash disbursements or cash receipts associated with bad debts, SPS responded that "an increase in the overall age of outstanding bills results in a higher working capital requirement and also translates into higher bad debt expenses as customers' bills

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141 SPS Ex. 53, Blair rebuttal at 35, Att. DAB-RR-R2 at 7, lines 159-161, and 33, line 10 (Labor O&M–Regular component of cash working capital calculation).

142 AXM Ex. 1, Brosch direct, Att. MLB-11 (SPS RFI response) at 1, ¶ (a).

143 AXM Ex. 1, Brosch direct at 22, Att. MLB-11 (SPS RFI response) at 1, ¶ (b).

reach the 180-day point."[144] Mr. Brosch objected that SPS provided no specific calculations to show that the study accomplishes any specific measurement of bad debt timing.[145]

Regarding vacation pay accrual, Mr. Brosch cited an SPS discovery response that "[i]n SPS's cash working capital calculations, there are no lead day calculations performed to explicitly include the effects of delayed payments of accrued vacation amounts. Regular payroll is included in the cash working capital calculation, which includes payments for vacation pay."[146]

Based on the evidence, including SPS's discovery responses, the ALJs find that SPS did not present sufficiently clear and detailed evidence to prove that its lead-lag study appropriately accomplishes the inclusion of the reserve/liability balances associated with the deferred tax assets relating to bad debt and vacation accrual reserves. Because SPS has the burden of proof and because, for reasons Mr. Brosch identified, the ALJs cannot determine from the evidence that including those tax-deferred assets in rate base would not cause rate base to be overstated, the ALJs recommend that those assets be excluded.

F. Regulatory Assets

1. Rate Case Expenses, Gain on Sale of Assets, and Coal Overcharge Credit

In its direct case, SPS estimated that $4,345,400 of rate case expenses will be incurred in this case and also sought recovery of $2,521,940 of unamortized rate case expenses from two prior SPS rate cases (Docket Nos. 42004 and 40824).[147] As mentioned previously,

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[144] AXM Ex. 1, Brosch direct at 22, Att. MLB-11 (SPS RFI response) at 2, ¶ (d).

[145] AXM Ex. 1, Brosch direct at 22-23.

[146] AXM Ex. 1, Brosch direct at 22-23, Att. MLB-12 (SPS RFI response) at 1, ¶ (d).

[147] SPS Ex. 6, Evans direct at 74-76; *Application of Southwestern Public Service Company for Authority to Change Rates and to Reconcile Fuel and Purchased Power Costs for the Period January 1, 2010 through June 30, 2012*, Docket No. 40824, Order (Jun. 19, 2013); Docket No. 42004, Order. To avoid duplication, all PFD discussion about rate case expenses is included in this section.

SOAH Order No. 6 severed issues regarding rate case expenses incurred in this case into a new case, Docket No. 44498. Under that order, as agreed by SPS, AXM, OPUC, and Staff, review of rate case expenses SPS and AXM incurred in connection with Docket Nos. 40824 and 42004 remains part of this case.

In rebuttal testimony, Mr. Evans proposed that the $2,521,940 in unamortized rate case expenses from Docket Nos. 42004 and 40824 be offset by a gain on sale of assets to Lubbock Power & Light (LPL) ($2,226,277), and (2) a credit attributable to an overcharge by coal supplier TUCO, Inc. (TUCO) ($83,753), leaving a net rate case expense balance of $211,911.[148] The evidence supports making SPS's proposed offset.

SPS, AXM, and Staff present three different proposals regarding how SPS should recover the unamortized rate case expenses from Docket Nos. 42004 and 40824:

- SPS proposes that the balance be recovered through base rates set in this case, using a one-year amortization period;[149]
- AXM proposes a two-year amortization period;[150] and
- Staff proposes that the balance be recovered through inclusion in the rider ultimately approved in Docket No. 44498.[151]

Staff witness Ms. Givens explained that Staff's recommendation is warranted to avoid over-recovery and given the relatively small amount involved.[152] In its reply brief, SPS indicated that

148 SPS Ex. 38, Evans rebuttal at 57. Mr. Evans's rebuttal testimony referred to $2,512,940, but he had corrected his direct testimony to instead use $2,521,940. *Cf* SPS Ex. 6, Evans direct at 75; SPS Ex. 38, Evans rebuttal at 56. The ALJs assume the correct number is $2,521,940. Using that number, the ALJs calculate the balance after the offset as $211,910 but assume the $1 difference is due to rounding and have used Mr. Evans's number ($211,911).

149 SPS Ex. 6, Evans direct at 29; SPS Ex. 38, Evans direct at 57, 60-61 (recommending a one-year amortization period to avoid overlapping amortization periods created by successive rate cases and because the $211,911 amount is not large and Docket No. 40824 concluded two years ago).

150 AXM Ex. 5, Carver direct at 24.

151 Staff Ex. 5A, Givens direct at 47.

152 Staff Ex. 5A, Givens direct at 47.

it does not oppose Staff's proposal, provided that the basis for and the reasonableness of SPS recovering the $211,911 are not subject to re-litigation.

In support of his proposed two-year amortization period, AXM witness Mr. Carver noted that the parties (including SPS) to the settlement in SPS's last base rate case agreed to rate case expenses from Docket Nos. 42084 and 42004 being recovered over a three-year amortization period, starting June 1, 2014.[153] He also opined that, even if SPS files another rate case within a year, a two-year amortization period should be used to minimize the risk of over-collection.[154]

SPS asks that, if the amortization period is longer than one year, the unamortized rate case expenses from Docket Nos. 42004 and 40824 be included in rate base with SPS earning a return on it. Staff objects to that request as contrary to Commission precedent. The ALJs agree with Staff. In Docket No. 40295, ETI proposed that "it be allowed to recover its rate case expenses over three years, and that it be allowed to recover a return on the unpaid balance of the expenses during that time."[155] The ALJ in that case recommended rejecting that proposal, explaining:

> In Docket No 30706, CenterPoint Energy Houston Electric (CenterPoint) sought to recover its rate case expenses over three years with a return on the unpaid balance. The Commission rejected CenterPoint's request for a return, explicitly noting its "practice of not permitting utilities to receive interest on unpaid rate-case expenses." Consistent with this clear Commission precedent, the ALJ recommends that ETI's request to recover a return on the unpaid balance of its rate case expenses during the three-year payoff period be denied.[156]

The Commission's final order adopted the ALJ's recommendation.[157]

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[153] AXM Ex. 5, Carver direct at 22; Docket No. 42004, Order, FF 23. The agreed rates took effect June 1, 2014. Docket No. 42004, Order, FF 15.

[154] AXM Ex. 5, Carver direct at 23.

[155] *Application of Entergy Texas, Inc. for Rate Case Expenses Pertaining to PUC Docket No. 39896*, Docket No. 40295, PFD (February 19, 2013) at 35.

[156] Docket No. 40295, PFD at 36 (citation omitted).

[157] Docket No. 40295, Order (May 21, 2013).

For the reasons identified by Ms. Givens, the ALJs agree with Staff that the $211,911 should be recovered by inclusion in the rider ultimately approved in Docket No. 44498.[158] The ALJs recommend granting SPS's request to specify that the basis for and the reasonableness of SPS recovering the $211,911 are not subject to re-litigation in Docket No. 44498.

2. Deferred Pension and OPEB Costs

PURA § 36.065 authorizes utilities to track and to defer pension and OPEB costs above a specific amount. Under the stipulations in SPS's last three base rate cases (Docket Nos. 38147,[159] 40824, and 42004), the parties agreed that SPS may track pension and OPEB costs above agreed amounts (up to a specific cap for part of that time), and to record the difference in a deferred account.[160] The amount of deferred pension and OPEB costs is approximately $3.6 million.[161] SPS witness Mr. Evans recommended amortizing these costs over one year;[162] AXM witness Mr. Carver recommended a two-year amortization period;[163] and OPUC witness Ms. Ramas recommended a three-year amortization period.[164]

SPS requests that, if the amortization period is longer than one year, the unamortized amounts be included in rate base with SPS earning a return on them at SPS's weighted average

[158] A SOAH order in Docket No. 44498 requires SPS and AXM to file on September 30, 2015, all rate case invoices up to that point in time and to file monthly updates thereafter. The order also requires that proposed procedural schedules be filed within seven working days after the Commission's initial final order in this case, including deadlines for SPS's and AXM's direct testimony that are no later than five weeks after that initial final order. Docket No. 44498, SOAH Order No. 4 (Jun. 25, 2015).

[159] *Application of Southwestern Public Service Company for Authority to Change Rates and to Reconcile Fuel and Purchased Power Costs for 2008 and 2009,* Docket No. 38147, Order (Mar. 25, 2011).

[160] SPS Ex. 6, Evans direct at 28.

[161] As of July 1, 2015, the unamortized balance of the pension and OPEB costs agreed to in Docket No. 42004 was $4,274,171 (total company). The sum of that amount and a ($690,662) net negative pension and OPEB credit since June 2014 equals $3,583,510 in pension and OPEB costs. AXM Ex. 5, Carver direct at 25; OPUC Ex. 1, Ramas direct at 33.

[162] SPS Ex. 6, Evans direct at 29; SPS Ex. 38, Evans rebuttal at 60-61 (recommending a one-year amortization period to avoid overlapping amortization periods created by successive rate cases).

[163] AXM Ex. 5, Carver direct at 24, Att. SCC-3 at C-8.

[164] OPUC Ex. 1, Ramas direct at 34 (recommending a three-year amortization period due to uncertainty over how long rates from this case will be in effect and the amount of the deferral balance).

cost of capital (WACC). Ms. Ramas agreed.[165] Given SPS's construction program and statements about its plans, the ALJs expect SPS to file its next rate case fairly quickly. The Commission's order in SPS's last rate case, Docket No. 42004, provides for deferred pension and OPEB tracker amounts to be recovered in base rates and amortized over a three-year period beginning June 1, 2014.[166] As noted previously, at a prehearing conference the parties agreed that rates set in this case will be retroactive for consumption occurring on and after June 11, 2015. Under the circumstances, the ALJs recommend a two-year amortization period beginning June 11, 2015, with the unamortized amounts included in rate base and SPS allowed to earn a return on them at SPS's WACC.

VII. RATE OF RETURN

A. Applicable Law and Background

AXM witness David C. Parcell explained that, in a cost of service rate case, the Commission establishes a public utility's rates in a manner designed to allow the recovery of the utility's costs, including capital costs. Under the rate base/rate of return method, the Commission allows a utility to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes and grants the utility the opportunity to earn a fair rate of return on the assets (*i.e.*, rate base) used and useful in providing service to the utility's customers. The rate of return is developed from the cost of capital, which is estimated by weighting the capital structure components (*i.e.*, debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these by their cost rates. This is known as the weighted cost of capital.[167]

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[165] OPUC Ex. 1, Ramas direct at 34 ("Since I am recommending the balance be amortized and recovered from ratepayers over a three-year period, it would be reasonable to include the unamortized balance in rate base as a regulatory asset.").

[166] AXM Ex. 5, Carver direct at 25; Docket No. 42004, Order, FF 24.

[167] AXM Ex. 4, Parcell direct at 3-4.

SPS witness Robert B. Hevert explained that the cost of capital (including the costs of both debt and equity) is based on the economic principle of "opportunity costs":

> Investing in any asset, whether debt or equity securities, implies a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk.[168]

Mr. Hevert noted that the cost of debt is defined, such as the interest rate or yield on debt securities, but the cost of equity is not directly observable and is not based on a contractual obligation. Rather, the cost of equity must be estimated or inferred based on market data and various financial models. Mr. Hevert further noted that there is a higher level of risk for equity investors because they have a claim on cash flows only after debt holders are paid. Because equity investors bear the "residual risk," they take greater risks and require higher returns than debt holders.[169]

Most of the experts testifying about rate of return issues in this case noted that the United States Supreme Court has set forth a minimum constitutional standard governing a fair rate of return:[170]

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having comparable risks. That return, moreover,

[168] SPS Ex. 9, Hevert direct at 13-14.

[169] SPS Ex. 9, Hevert direct at 14.

[170] SPS Ex. 9, Hevert direct at 14-16; AXM Ex. 4, Parcell at 4-5; Staff Ex. 6A, Winker direct at 8-9; TIEC Ex. 4, Gorman direct at Bates 18; and DOE Ex. 1, Reno direct at 2.

> should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[171]

Additionally, the Commission's rule at 16 TAC § 25.231(c) reflects the constitutional standard:

> (1) Rate of return. The commission shall allow each electric utility a reasonable opportunity to earn a reasonable rate of return, which is expressed as a percentage of invested capital, and shall fix the rate of return in accordance with the following principles.
>
> (A) The return should be reasonably sufficient to assure confidence in the financial soundness of the electric utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low because of changes affecting opportunities for investment, the money market, and business conditions generally.
>
> (B) The commission shall consider efforts by the electric utility to comply with the statewide integrated resource plan, the efforts and achievements of the electric utility in the conservation of resources, the quality of the electric utility's services, the efficiency of the electric utility's operations, and the quality of the electric utility's management, along with other applicable conditions and practices.
>
> (C) The commission may, in addition, consider inflation, deflation, the growth rate of the service area, and the need for the electric utility to attract new capital. The rate of return must be high enough to attract necessary capital but need not go beyond that. In each case, the commission shall consider the electric utility's cost of capital,

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[171] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944); *see also Bluefield Waterworks & Improvement Co. v. Public Serv. Comm'n of W. Va.*, 262 U.S. 679, 692-693 (1923) ("A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.").

which is the weighted average of the costs of the various classes of capital used by the electric utility.

Below, the ALJs discuss contested issues concerning: (1) SPS's return on equity, which is estimated and, therefore, subject to different recommendations by rate of return witnesses; (2) SPS's cost of debt; (3) SPS's capital structure; and (4) the recommended rate of return.

B. Return on Equity

1. SPS's Current Ratings

SPS is a New Mexico corporation and wholly owned electric utility subsidiary of Xcel Energy. Xcel Energy is a registered holding company that owns a number of electric and natural gas utility operating companies. SPS is rated BBB by Fitch, Baa1 by Moody's, and A- by S&P.[172] All three ratings are considered to be investment grade. Staff witness Ms. Winker explained that investment grade ratings indicate that SPS has access to capital on reasonable terms and, thus, has financial integrity.[173] AXM witness Mr. Parcell testified that SPS's ratings are above the common rating categories of most electric utilities.[174]

According to SPS witness Ms. Schell, financial integrity means that "a company is able to attract the capital required to fund its operations and investment requirements over the course of an economic cycle, in all types of market conditions, and at a reasonable cost."[175] Ms. Schell indicated that the financial integrity of a regulated utility like SPS is mostly a function of its capital structure, return on equity, and cash flow. She explained that the Commission should be concerned with SPS's credit ratings because they affect the availability and cost of both long- and short-term capital.[176] In Ms. Schell's opinion, SPS is at risk of a downgrade if it does not

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172 SPS Ex. 8, Schell direct at 23.

173 Staff Ex. 6A, Winker direct at 5-6.

174 AXM Ex. 4, Parcell direct at 13.

175 SPS Ex. 8, Schell direct at 11.

176 SPS Ex. 8, Schell direct at 12-13.

receive supportive cost recovery in this case. She testified that her concerns are based on a May 2, 2014 S&P report and a June 2, 2014 Fitch report. Also, Moody's has commented on the regulatory lag that SPS experiences in Texas and New Mexico, noting that SPS's remedy has been to file successive rate cases in both jurisdictions. She concluded it is important for SPS to achieve and maintain strong credit ratings, particularly now that SPS is in the midst of a capital investment program, which creates an advanced level of risk for the company.[177]

2. General Economic Conditions

AXM witness Mr. Parcell reviewed economic statistics from 1975 to present, noting that a long review period—over four full business cycles—allows analysts to see cost-of-capital trends. He observed that, until the end of 2007, the United States economy had enjoyed general prosperity and stability since the 1980s. However, in 2008 and 2009, the economy declined significantly. The decline has been referred to as the "Great Recession."[178] In mid-2009, the economy began to expand, although at a slow and uneven rate. According to Mr. Parcell, the impacts of the recession will be felt for a long time. Mr. Parcell noted that one impact of the Great Recession has been a reduction in actual and expected investment returns and a corresponding reduction in the costs of capital.[179] Mr. Parcell testified that there has been a decline in investor expectations of returns, which is evident in: (1) lower interest rates on bank deposits; (2) lower interest rates on U.S. Treasury and corporate bonds; (3) lower increases in social security cost-of-living benefits; and (4) lower authorized returns on common equity for regulated utilities.[180]

Mr. Parcell's view that there has been a reduction in the costs of capital was shared by TIEC witness Michael P. Gorman. Mr. Gorman testified that there has been a clear pattern of

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[177] SPS Ex. 8, Schell direct at 24-25; Tr. 173.

[178] AXM Ex. 4, Parcell direct at 8.

[179] For example, the current debt costs that utilities pay on new debt is low, near the low point of the last few decades. AXM Ex. 4, Parcell direct at 12.

[180] AXM Ex. 4, Parcell direct at 11; *but see* Tr. at 1,227-1,265 (At the time of the hearing, the current yield on a 10-year treasury bond had risen from 1.94%, cited in Mr. Parcell's testimony, to 2.47%.).

low capital costs over the past five years. He noted that regulatory commissions have been reducing the authorized returns on equity, consistent with the pattern of declining or stable interest rates.[181]

OPUC witness Carol Szerszen indicated that, although there is uncertainty as to whether interest rates will rise, the Federal Reserve Bank is currently committed to maintaining a low interest rate environment until a sustainable economic trend of recovery has been established. Dr. Szerszen foresaw zero to little upward adjustments in interest rate trends and concluded that the Commission should adopt a rate of return that reflects the current low fixed income capital market.[182]

SPS witness Mr. Hevert indicated that data from the market points to a probability of increasing interest rates. Potential interest rate increases are a risk for utility investors.[183] Mr. Hevert also testified that capital markets have become increasingly unsettled. He noted that between January 30 and June 3, 2015:

- Electric utility stock prices fell by 13.11% while the overall market increased by 6.80%;
- The 30-year Treasury yield increased by 86 basis points;
- Electric utility dividend yields increased by 69 basis points; and
- Expected inflation increased by approximately 20 to 30 basis points.[184]

According to Mr. Hevert, this amount of instability confirms that: (1) estimating the cost of equity is not an entirely mathematical exercise; (2) the methods used may change from case to case; and (3) the returns authorized in other jurisdictions provide a relevant, observable, and

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[181] Tr. at 1207; TIEC Ex. 4, Gorman direct at Ex. MPG-11.

[182] OPUC Ex. 10, Szerszen direct at 16-18, and 22.

[183] SPS Ex. 40, Hevert rebuttal at 42-43.

[184] SPS Ex. 40, Hevert rebuttal at 17.

verifiable benchmark for assessing the reasonableness of assumptions, results, and conclusions drawn by the return on equity witnesses in this case.[185]

Mr. Hevert further suggested that there are additional economic factors that should be taken into consideration when determining SPS's cost of equity:

- *SPS's planned capital investment program.* SPS plans to invest approximately $2.75 billion of additional capital from 2014 to 2017.[186]
- *Customer concentration.* Approximately 80% of SPS's 2013 retail electric sales and 70% of its retail electric revenues were derived from commercial and industrial customers. Approximately 34% of total electric sales and 28% of total electric revenues are attributable to sales for resale in the wholesale electric market. Thus, SPS has a higher concentration of large commercial and industrial customers than the proxy companies.[187]
- *Risks associated with environmental regulations.* SPS is heavily dependent on coal-fired generation. Federal environmental regulations add substantial risk because the Company may need to invest additional capital or face closure or curtailment of generation capacity.[188]
- *SPS's small size relative to the proxy group.* SPS is significantly smaller than the average for the proxy group companies, smaller in numbers of customers and market capitalization. In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses.[189]

Intervenor witnesses Dr. Szerszen and Mr. Parcell disputed Mr. Hevert's suggestion that additional factors must be taken into account when determining SPS's cost of equity. Mr. Parcell noted that the above factors are already considered by the rating agencies in their assignment of credit ratings to SPS. As to the additional costs for environmental compliance, Mr. Parcell stated that utilities have been investing in environmental compliance equipment for

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185 SPS Ex. 40, Hevert rebuttal at 17.

186 SPS Ex. 9, Hevert direct at 43-47.

187 SPS Ex. 9, Hevert direct at 47-49.

188 SPS Ex. 9, Hevert direct at 49-51.

189 SPS Ex. 9, Hevert direct at 51-52.

decades.[190] Dr. Szersen also noted that SPS reported in its 2015 Securities and Exchange Commission (SEC) Form 10-K that it meets all current environmental regulations and that future expenses for compliance are expected to be recoverable through the regulatory process. Moreover, according to Dr. Szersen (1) there is no evidence that SPS's large commercial and industrial customers are leaving the SPS system; and (2) SPS, as a subsidiary of Xcel Energy, enjoys strong access to the debt and equity markets; thus, SPS's construction program does not necessarily increase its business risk and its small size does not require additional consideration.[191]

3. Risk Proxy Groups

SPS is not a publicly traded company. Therefore, the testifying experts in this case analyzed groups of comparison or proxy companies to determine SPS's cost of common equity. A proxy group is composed of companies with a similar risk profile to SPS's.[192]

To form a proxy group, SPS witness Mr. Hevert used companies that Value Line Investment Survey (Value Line) classified as electric utilities and excluded companies:

- that did not consistently pay quarterly cash dividends;
- that were not covered by at least two utility industry equity analysts;
- that did not have investment grade senior unsecured bond and/or corporate credit ratings from S&P;
- whose regulated operating income over the three most recently reported fiscal years comprised less than 60% of the respective totals for that company;
- whose regulated electric operating income over the three most recently reported fiscal years represented less than 90% of total regulated operating income; and

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[190] AXM Ex. 4, Parcell direct at 38-39.

[191] OPUC Ex. 7, Szerszen direct at 19-24.

[192] Tr. at 1,102.

- that were known to be party to a merger or other significant transaction.[193]

Mr. Hevert then examined the operating profile of the 16 companies that met his criteria and subsequently excluded Edison International based on recent financial information. Mr. Hevert further noted concerns with another company, Cleco Corporation (Cleco), which was recently acquired by investors. He did not initially exclude Cleco. But in his rebuttal testimony, Mr. Hevert removed Cleco, Hawaiian Electric Industries, Inc. (Hawaiian Electric); and NextEra Energy from his proxy group. He then performed more analyses.[194]

TIEC witness Mr. Gorman and DOE witness Maureen L. Reno used the same proxy group as Mr. Hevert did in his rebuttal testimony, excluding the three companies he determined did not have reasonable risk (Hawaiian Electric, NextEra Energy, and Cleco). These three companies were recently involved in merger and acquisitions; thus, they have enhanced shareholder value.[195] In 2013, this proxy group had an average common equity ratio of 49.0%, including short-term debt, from SNL Financial and 51.7%, excluding short-term debt, from Value Line.[196]

AXM witness Mr. Parcell used a different proxy group, which he selected from a group of electric companies that: (1) had a market cap of $10 billion or more; (2) had electric revenues of 50% or more; (3) possessed a common equity ratio of 40% or greater; (4) had a Value Line safety rating of 1, 2, or 3; (5) had an S&P stock ranking of A or B; (6) received S&P and Moody's bond ratings of A or BBB; and (7) currently paid dividends. Mr. Parcell also used Mr. Hevert's proxy companies for analyses.[197]

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[193] SPS Ex. 9, Hevert direct at 19.

[194] SPS Ex. 9, Hevert direct at 21; SPS Ex. 40, Hevert rebuttal at 10, Att. RBH-RR-R8.

[195] TIEC Ex. 4, Gorman direct at Bates 19, MPG-2; DOE Ex. 1, Reno direct at 15.

[196] TIEC Ex. 4, Gorman direct at Bates 21.

[197] AXM Ex. 4, Parcell direct at 16-17.

For her proxy group, Staff witness Ms. Winker chose companies that:

- had a capital structure between 40% and 60%;
- had a positive long-term forecast growth rate from both Zacks and Value Line;
- were covered by at least two rating agencies;
- has an outlook rated as stable by S&P;
- did not have recent or potential merger activities or major capital expansion; and
- did not have recent dividend cuts or omissions.[198]

OPUC witness Dr. Szerszen chose a larger proxy group than Mr. Hevert's. She relied on operating revenues from each company's annual report to the SEC instead of operating income; she included Xcel Energy in her analysis; and she eliminated companies whose regulated electric operating income represented less than 70% (rather than 90%) of total regulated operating income.[199]

In rebuttal, Mr. Hevert took issue with the proxy groups of Dr. Szerzen and Ms. Winker. Dr. Szerszen used four companies excluded by all other witnesses. For instance, Dr. Szerszen included natural gas utilities and a company, Edison International, which had one unit placed into Chapter 11 bankruptcy.[200] Ms. Winker also included a natural gas distribution utility, Sempra Energy, which no other analyst chose. Mr. Hevert stated that only six of Ms. Winker's sixteen proxy companies passed his screening criteria.[201]

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[198] Staff Ex. 6A, Winker direct at 13.

[199] OPUC Ex. 10, Szerszen direct at 8-9.

[200] Mr. Parcell also included this company in his proxy group. SPS Ex. 40, Hevert rebuttal at Exh. RBH-RR-R8.

[201] SPS Ex. 40, Hevert rebuttal at 24, 49-51, Exh. RBH-RR-R8.

4. Models Used by Testifying Witnesses and Range of Results

Mr. Hevert noted that no one financial model is more reliable than others at all times and under all market conditions. Thus, determining the cost of equity is not a strict mathematical exercise—rather, it requires reasoned judgement.[202] All of the six return-on-equity witnesses used some variant of the discounted cash flow (DCF) model. All witnesses used one or more additional models, such as the capital asset pricing model (CAPM), the comparable earnings (CE) analysis, and the risk premium analysis. As noted above, Mr. Hevert, in rebuttal testimony, modified his proxy group and updated his inputs, which changed the results of all four of his models.[203] The results of all the analysts' models are detailed below:

Model	Result (%)	Overall Cost of Equity Recommendation (%)
	Hevert (direct)[204]	
Constant growth DCF	8.39-10.41	Range: 10.0 to 10.6
Multi-stage DCF	9.61-10.20	
CAPM	10.66-11.70	Final: 10.25
Risk premium	10.11-10.85	
	Hevert (rebuttal)[205]	
Constant growth DCF	8.33-9.66	Range: 9.56 to 10.16
Multi-stage DCF	9.02-10.17	(estimated)[206]
CAPM	9.82-10.55	
Risk premium	10.08-10.64	Final: 9.81 (estimated)
	Parcell[207]	
DCF	8.0-8.8	Range: 8.8 to 10.0
CAPM	6.3-6.7	
CE	9.0-10.0	Final: 9.4

[202] SPS Ex. 40, Hevert rebuttal at 11.

[203] SPS Ex. 40, Hevert rebuttal at 10, Exh. RBH-RR-R2.

[204] SPS Ex. 9, Hevert direct at 30, 35-36, 39, 40, and 63.

[205] SPS Ex. 40, Hevert rebuttal at 9, Att. RBH-RR-R1 through RBH-RR-R26; *also see* TIEC initial brief (RR) at 33-34 and Att. A to the brief.

[206] As TIEC explained in its initial brief (RR), TIEC adjusted Mr. Hevert's rebuttal by 44 basis points. TIEC initial brief (RR) at 34.

[207] Mr. Parcell conducted one constant growth analysis using his proxy group and using Mr. Hevert's. AXM Ex. 4, Parcell direct at 20, 24, and 28.

	Gorman[208]	
DCF sustained	8.27-8.35	Range: 8.9 to 9.4
DCF analysts	8.43-8.59	
Multi-stage DCF	8.2-8.36	Final: 9.15
Risk premium	9.21-9.56	
CAPM	9.10	
	Szerszen[209]	
DCF	7.64-9.00	Final: 9.2
Risk Premium	8.51-9.93	
	Reno[210]	
DCF	8.09-9.02	Final: 9.0
Multi-Stage DCF	8.46-9.2	
CAPM	9.37, 9.69	
	Winker[211]	
DCF	8.52	Range: 8.49-9.53
Multi-stage DCF	8.46	
CAPM	7.09	Final: 9.3
Risk Premium	9.53	

State Agencies and DOE argue that Staff and Intervenor witnesses' recommendations cluster in one range, while SPS witness Mr. Hevert's return on equity is an outlier: 85 basis points higher than Mr. Parcell's. Similarly, TIEC argues that Mr. Hevert's recommendation is unrealistic and inflated. AXM contends that the record does not support Mr. Hevert's recommendation, arguing that, since 2006, the Commission has adopted a return on equity at least 100 basis points lower than Mr. Hevert's proposed return on equity.

Other Intervenor return-on-equity witnesses also took issue with Mr. Hevert's analysis. Dr. Szerszen testified there were three problems with Mr. Hevert's multi-stage DCF model: (1) his sole reliance on investment analyst earnings growth rate expectations (and his failure to review retained earnings and book value growth rate projections); (2) his use of Gross Domestic Product (GDP) growth as a proxy for longer-term dividend and earnings growth; and (3) his assumption that the average 1990-2013 dividend payout ratio was representative of a long-term

208 TIEC Ex. 4, Gorman direct at Bates 34, 37, 40, 45-47.

209 OPUC Ex. 10, Szerszen direct at 4, 26, and 28.

210 DOE Ex. 1, Reno direct at 21, 26, and 28.

211 Staff Ex. 6A, Att. AW5, AW7, 25, 28, 31-32; SPS Ex. 40, Hevert rebuttal, Att. RBH-RR9 at 2; Tr. at 1,321.

expected payout ratio. Additionally, Dr. Szerszen had concerns with Mr. Hevert's CAPM, disputing his sole reliance on analysts' earnings growth projections. She also disputed his risk premium analysis because it was complicated and over-reaching. Additionally, she took issue with an underlying assumption by Mr. Hevert to account for low interest rates.[212]

AXM witness Mr. Parcell testified that Mr. Hevert's DCF analyses were biased upward. Mr. Parcell took issue with Mr. Hevert's reliance on analysts' forecasts, his use of only forecasted data, and his failure to include historical (actual) data from Value Line. Like Dr. Szerszen, Mr. Parcell disputed Mr. Hevert's use of GDP growth as a proxy for longer-term dividend and earnings growth and his use of only historical growth rates in his GDP input. As to the CAPM and risk premium analyses, Mr. Parcell disputed Mr. Hevert's use of projected interest rates, rather than the current yield.[213]

DOE witness Ms. Reno disagreed with Mr. Hevert's adjustment for quarterly dividend payout; his use of analysts' estimates of earnings growth; and his use of GDP growth as a proxy for longer-term dividend and earnings growth in his DCF analyses.[214]

TIEC witness Mr. Gorman testified that Mr. Hevert's constant growth DCF assumed unreasonable growth rates for his high-end estimate. According to Mr. Gorman, it is not rational to expect a utility to grow considerably faster than the rate of GDP growth over the long term. Mr. Gorman also stated that Mr. Hevert inflated his long-term growth rate for his multi-stage DCF because he assumed that a historical real GDP growth rate was appropriate for projecting future growth. Concerning the CAPM, Mr. Gorman suggested Mr. Hevert used inflated market risk premiums of 10.14% from Bloomberg and 9.69% from Value Line; these premiums were based on market DCF returns of 13.32% and 12.88%, respectively.[215] Mr. Gorman testified that

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[212] OPUC Ex. 7, Szerszen direct at 6-7, 13, 16-17.

[213] AXM Ex. 4, Parcell direct at 30-32, 34-35, 37-38.

[214] DOE Ex. 1, Reno direct at 21-22, 25.

[215] TIEC Ex. 4, Gorman direct at Bates 53, 61. The market risk premiums consisted of stock market index growth rates of approximately 11.18% and 10.31% and an expected dividend yield of 2.14% and 2.57% respectively.

Mr. Hevert's sustainable growth rates are too high to be a rational outlook for sustainable, long-term stock market growth. As to Mr. Hevert's risk premium analysis, Mr. Gorman disputed Mr. Hevert's regression analysis to Treasury bond yields, which increased his risk premium to a range of 5.40% to 6.93% and allowed him to arrive at his return on equity estimates in the range of 10.11% to 10.85%. Mr. Gorman calculated that if Mr. Hevert's non-adjusted risk premium of 4.44% were added to the Blue Chip treasury bond yield outlook of 3.70% over the next two years, it would result in a return estimate of 8.14%, a low yield in line with the current low-cost interest environment.[216]

In turn, Mr. Hevert testified that the analyses conducted by the Staff and Intervenor witnesses contained flaws that drove their results downward. Over the past year, the average authorized return on equity for vertically integrated electric utilities (utilities that, like SPS, provide generation, transmission, and distribution functions) was 9.95%. Mr. Hevert took issue with the models used by Staff and Intervenor witnesses, which produced return-on-equity estimates that were 100 basis points and more below the return authorized for other similar electric utilities. He noted that the lower end of his recommended range (10.00%) is only eight basis points removed from the average authorized return on equity.[217]

Mr. Hevert also detailed his concerns with the other analysts' analyses and their results. He conducted an extensive review of the analyses of Ms. Winker, Dr. Szerszen, Ms. Reno, and Messrs. Gorman and Parcell. This PFD does not discuss Mr. Hevert's detailed rebuttal but summarizes his opposition:[218]

- DCF-based methods define the cost of equity as the discount rate that sets the current market price of a stock equal to the present value of the cash flows expected from owning that stock. The cash flows include both dividends received and the price at which the stock eventually is sold. In calculating

[216] TIEC Ex. 4, Gorman direct at Bates 53, 63, 65.

[217] SPS Ex. 40, Hevert rebuttal at 50, 58.

[218] Mr. Hevert's rebuttal of each rate of return witness's testimony is found at SPS Ex. 40, Hevert rebuttal at 18-155.

expected cash flows, the opposing Intervenor and Staff return witnesses rely on growth rates that Mr. Hevert maintains are inappropriately low. The return witnesses, in his opinion, also assume that all dividends will be received at year-end, not on a quarterly basis. Mr. Hevert gives less weight to the constant growth DCF method because it assumes that the recently high utility stock valuations will persist in perpetuity. He testified that DCF estimates as low as 8.50% fail to meet the *Hope* and *Bluefield* standard and should be given no weight in determining SPS's return on equity.[219]

- Mr. Hevert explained that "Risk Premium methods are based on the fundamental financial principle that equity investors assume greater risk than do debt investors and, therefore, require higher returns. The measure of that incremental return is the 'Equity Risk Premium,' or the difference between the required return on debt and the required return on equity."[220] He noted that the equity risk premium is not constant over time. Rather, as interest rates fall, risk premium increases. He concluded that the risk premium analyses of the opposing witnesses failed to properly reflect that well-documented relationship and under-estimated SPS's cost of equity.[221]

- The CAPM, which also is a risk premium-based method, assumes that investors must be compensated for the time value of money and for taking on additional risk. According to Mr. Hevert, the market risk premium, which weighs heavily in CAPM estimates, reflects the additional return that investors expect to receive by investing in the market as a whole over the return they would receive by investing only in long-term Treasury bonds. Mr. Hevert took issue with the market risk premium estimates of Ms. Reno and Mr. Parcell, contending they developed such estimates based on historical market returns and interest rates, and they have assumed relationships among those two variables that did not reasonably reflect current or expected market conditions. As a result, their estimates and, therefore, their return on equity estimates were unreasonably low.[222]

- Ms. Winker and Dr. Szerszen base their analyses on proxy companies that are fundamentally incomparable to SPS or that conflict with the witnesses' own screening criteria. This is a fundamental concern, stated Mr. Hevert, because using companies not reasonably comparable to SPS calls into question the basis of their conclusions and recommendations.[223]

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219 SPS Ex. 40, Hevert rebuttal at 14-15.

220 SPS Ex. 40, Hevert rebuttal at 15.

221 SPS Ex. 40, Hevert rebuttal at 15.

222 SPS Ex. 40, Hevert rebuttal at 15, 102, 141.

223 SPS Ex. 40, Hevert rebuttal at 15, 23, 46.

A short summary of the expert recommendations may be helpful here:[224]

WITNESS	ROE RANGE		RETURN ON EQUITY RECOMMENDATION
	LOW	HIGH	
Ms. Winker (Staff)	8.49%	9.53%	9.30%
Dr. Szerszen (OPUC)	-	-	9.20%
Ms. Reno (DOE)	8.10%	9.70%	9.00%
Mr. Gorman (TIEC)	8.90%	9.40%	9.15%
Mr. Parcell (AXM)	8.80%	10.00%	9.40%
Mr. Hevert (SPS)	10.00%	10.60%	10.25%

To some degree, the different return on equity recommendations of Mr. Hevert and the opposing witnesses can be explained by their different views of the current (early summer 2015) market conditions, expected market conditions, and authorized returns for other utilities. With regards to the latter, the ALJs found the authorized returns on equity of other electric utilities in 2014 were instructive. The average returns are lower than Mr. Hevert's recommended return on equity and higher than any opposing analysts' recommended return:[225]

Types of Electric Utilities	Average Return on Equity
Transmission and Distribution	9.43%
Vertically Integrated	10.07%
Vertically Integrated (Excluding Connecticut Light & Power)[226]	10.10%
Vertically Integrated (Excluding Virginia Utilities)[227]	9.87%
Vertically Integrated (Excluding Connecticut Light & Power and Virginia Utilities)	9.91%

SPS takes issue with the lower recommended returns on equity suggested by the opposing witnesses. For example, SPS asked Mr. Gorman whether he was proposing to award

224 SPS Ex. 40, Hevert rebuttal at 12.

225 SPS Ex. 66. These percentages include litigated and settled cases. Tr. at 1,177-1,178.

226 Connecticut Light & Power is a transmission and distribution utility. Tr. at 1,175-1,176.

227 Virginia law allows the regulatory agency to increase a return on equity by up to 200 basis points. Tr. at 1,133-1,134.

SPS the second lowest return on equity awarded in the last 30 years. Mr. Gorman hedged his response. He testified that he was "recommending that the Commission recognize that SPS's current market cost of capital is at historically low levels and [adopt an] authorized return on equity consistent with those low capital market costs, which I believe is around 9.15%."[228]

5. Impact of Return on Equity on SPS's Financial Integrity

TIEC witness Mr. Gorman testified that his 9.15% return on equity recommendation is sufficient to maintain SPS's financial integrity. He compared SPS's key credit rating financial ratios using his proposed return on equity, his adjusted capital structure, and SPS's proposed embedded debt cost to S&P's benchmark financial ratios. In making this comparison, he used S&P's new credit metric ranges.[229]

Mr. Hevert disputed Mr. Gorman's assessment because, in his opinion, it was based on a set of pro forma calculations that would provide little insight as to how investors would view a return that is so far below industry standards.[230]

6. ALJs' Analysis and Recommendation

The analysts' different recommendation flowed from their choices of proxy companies.[231] The ALJs find that the proxy groups used by Dr. Szerzen and Ms. Winker contained a number of companies that all other return on equity analysts excluded. And Dr. Szerzen and Ms. Winker eliminated companies that the other analysts included. In sum, Dr. Szerzen included or excluded five companies, at odds with other analysts, out of a total of 32 companies. Ms. Winker included or excluded 10 companies at odds with the other analysts.

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228 Tr. at 1,190-1,191.

229 TIEC Ex. 4, Gorman direct at 46-47.

230 SPS Ex. 40, Hevert rebuttal at 16-17.

231 *See* SPS Ex. 40, Hevert rebuttal at Exh. RBH-RR-R8, which is a useful chart showing the analysts' proxy companies.

However, Mr. Parcell also included or excluded seven companies that the other analysts excluded or included, respectively. Moreover, Mr. Parcell either included or excluded five additional companies that either only Dr. Szerszen or Ms. Winker excluded or included. Although Mr. Hevert did not take issue with Mr. Parcell's proxy group, the evidence suggests that the proxy group used by Mr. Parcell was also quite different than the return on equity analysts' choice of proxy group companies.

The ALJs conclude that Ms. Winker's proxy group appeared to be more of an outlier in comparison to all other analysts; thus, her return on equity recommendation is more susceptible to criticism. However, overall, the ALJs did not find a persuasive reason, based solely on the choice of a particular proxy group, to disregard any analyst's recommendation.

The different return on equity recommendations also flowed from the types and results of the models the analysts used. Mr. Hevert offered reasonable arguments as to why other analysts' model choices, modeling decisions, and outcomes were unpersuasive. In turn, Messrs. Parcell and Gorman and Dr. Szerszen offered reasonable arguments why Mr. Hevert's choices, decisions, and outcomes were weighted in favor of SPS. But the ALJs are not persuaded that Mr. Hevert's recommended 10.25% return on equity should be disregarded simply because the Commission (and other regulatory agencies) have not adopted Mr. Hevert's previous recommendations or because it is 85 basis points above the second highest recommendation (that of Mr. Parcell).[232] The ALJs observe that Mr. Hevert's rebuttal analysis was more persuasive than the analysis of the other return on equity witnesses. In contrast, DOE witness Ms. Reno's recommendation of 9.0% was unpersuasive because Ms. Reno lacked the experience of the other return on equity witnesses and had the lowest recommendation. The ALJs find it reasonable to exclude her recommendation as an outlier. The ALJs are also troubled by the overall recommendations of Mr. Gorman and Dr. Szerszen, which were, respectively, only 15 and 20 basis points higher than that of Ms. Reno. The ALJs also note that Ms. Winker's overall recommendation, based on her outlier group of proxy companies, was only 30 points higher than

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[232] Similarly, the ALJs did not disregard the recommendations of Ms. Winker, Mr. Parcell, or Mr. Gorman because the Commission did not adopt their recommendations in previous cases.

Ms. Reno's. In comparison, the ALJs find Mr. Hevert's rebuttal and Mr. Parcell's analyses and recommendations more reasonable.

The ALJs further note that an average return on equity based on the recommendations of Mr. Gorman (9.15%), Dr. Szerszen (9.2%), Ms. Winker (9.3%), Mr. Parcell (9.4%), and Mr. Hevert (both 9.81% and 10.25%) is 9.518%, or 9.52% when rounded. The ALJs find that this return on equity is unreasonable because it provides SPS with only a slightly higher return than the average authorized return in 2014 for transmission and distribution utilities, which was 9.48%. Such a return is lower that the lowest authorized return of any vertically integrated utility in 2014, which was 9.91%.[233] The ALJs agree with Mr. Hevert that awarding SPS a return that is 39 basis points lower than the 2014 average is unreasonable. A return of 9.52% is not commensurate with returns on investments in other vertically integrated utilities having comparable risks.

The ALJs recommend a 9.7% return on equity. Such a return is slightly below Mr. Hevert's average rebuttal return on equity and falls within the range recommended by Mr. Parcell. It is reasonable when compared to the returns of other vertically integrated utilities. This return, moreover, is sufficient to assure confidence in SPS's financial integrity, and will allow SPS to maintain its credit and attract capital.

C. Cost of Debt

The Commission's cost of service rule provides that the cost of debt is the actual cost of debt at the time of issuance, plus adjustments for premiums, discounts, and refunding and issuance costs.[234] SPS calculated a 5.98% cost of long-term debt, using the Commission's RFP, Schedule K-3.[235] OPUC recommends an adjustment to SPS's requested cost of debt, to eliminate the yearly amortization costs associated with SPS's 2003 and 2006 interest rate swaps. Staff

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233 Excluding Virginia Utilities and Connecticut Light and Power.

234 16 TAC § 25.231(c)(1)(C)(i).

235 SPS Ex. 8, Schell direct at 31.

witness Ms. Winker indicated that SPS's proposed cost of debt was reasonable.[236] DOE's recommendation to include short-term debt in the calculation of SPS's cost of debt and in its capital structure is addressed later in this PFD.

SPS witness Ms. Schell explained that an interest rate swap is a mechanism where a utility can actively manage risk and mitigate interest rate volatility in connection with an upcoming bond offering. According to Ms. Schell, an interest rate swap gives a utility a chance to lock in an interest rate between the time of the swap and the time of the bond issuance to insure against increases in the interest rate that will have to be paid on the bond. Ms. Schell testified that SPS enters into an interest rate swap to reduce uncertainty in the interest rate of a future bond issuance but does so only upon receiving SPS board approval.[237] SPS also must file for approval of interest rate swaps with the New Mexico Commission.[238]

OPUC witness Dr. Szerszen takes issue with two interest rate swaps. The most recent interest rate swap occurred on July 20, 2006, in anticipation of SPS's $200 million debt issuance planned for October 2006. SPS entered into a 5.6625% forward swap for $50 million, which locked in the rate for 25% of SPS's total expected debt issuance. In October 2006, SPS priced the $200 million of senior notes at 5.6%. Simultaneous to the pricing of the notes, the forward swap unwound, resulting in a net settlement loss to SPS of $2,049,113. The loss on the swap was a result of declining interest rates.[239] SPS subtracted the unamortized balance of the interest rate swap amount from the net proceeds, which lowered SPS's effective debt rate by a few basis points.[240]

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[236] Staff Ex. 6A, Winker direct at 34.

[237] SPS's risk management policy states that swaps must qualify for hedge accounting and will not be used for speculative purposes. SPS Ex. 39, Schell rebuttal at 20.

[238] SPS Ex. 39, Schell rebuttal at 20. The New Mexico Commission approved SPS's request to enter into the interest rate swaps at issue here.

[239] OPUC Ex. 7, Szerszen direct at 24-25.

[240] SPS Ex. 39, Schell rebuttal at 21.

Similarly, SPS also had interest rate swap losses associated with its 2003 unsecured notes. SPS's cost of debt reflects the 2003 issuances; thus, OPUC is opposed to the inclusion of its costs in SPS's long-term debt. Using SPS's requested Texas retail rate base of $1,560,042,382, OPUC's adjustments reduce the debt cost requirement by $156,004 and the pre-tax equity requirement by $168,005. Dr. Szerszen calculated that the total cost to ratepayers for SPS's inclusion of the 2003 interest rate swaps is $324,009.[241]

According to Dr. Szerszen:

> Interest rate swaps could be compared to a situation where a utility company is given two options to purchase a power plant. The first option would be to purchase at book value. The other option would involve an element of risk. The utility would be given either a 20% discount to book value or charged a 20% premium over book value. Cards for the 20% discount or 20% premium are put in a hat and the utility company draws one card from the hat. The hat option becomes a much more likely choice for the utility company if ratepayers are required to pay the 20% premium. On the other hand, the company would most likely not attempt to pull from the hat if shareholders were responsible for the 20% premium. In this case, the book value option would most likely be selected. If the hat option is selected, the company has a 50% chance of paying more for the plant and a 50% chance of paying less. The Company effectively has nothing to lose by selecting the hat option if ratepayers are required to pay the potential premium for the plant cost.[242]

SPS witness Ms. Schell takes issue with Dr. Szerszen's comparison of an interest swap to drawing cards from a hat. Ms. Schell testified that an interest-rate lock or swap is similar to a situation in which a consumer locks in a mortgage interest rate when purchasing a house. The market rate may go up or may go down after the interest rate is locked, but the consumer has eliminated uncertainty and, more importantly, has protected against the risk that the rate will rise above a level that the consumer can pay. According to Ms. Schell, there were indications interest rates were rising when SPS entered into the 2006 swap. At that time, the expectation was that the 10-year U.S. Treasury bond yield would rise. On July 20, 2006, the date the hedge

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[241] OPUC Ex. 7, Szerszen direct at 25.

[242] OPUC Ex. 7, Szerszen direct at 25-26.

was entered into, the federal fund futures indicated a 65% probability of an increase in interest rates. Economists at Citibank and Barclays, who were SPS's lead underwriters for the bond transaction, both believed that an interest rate hike was the most likely next move by the Federal Reserve. The rationale for the Federal Reserve to move rates higher was based on continued robust growth and recent upward revisions to core consumer inflation.[243]

Both parties cite Commission precedent to support their positions. OPUC equates interest rate swaps to hedges and notes that the Commission prohibited utilities from using interest rate hedges in financing cases.[244] In those cases, the Commission found that hedges created additional costs and risks if, for instance, the transition bonds were not issued or the amount differed.[245] OPUC argues that SPS's losses on the interest swaps are indicative of the risky nature of these transactions. Further, OPUC contends, utility companies will have an incentive to buy hedging contracts if ratepayers are required to pay for any losses that may occur.

OPUC also argues that interest rate swap losses are not a debt issuance cost, a debt refunding cost, a debt premium, or a debt discount. Therefore, SPS's swap losses do not comply with the rule's reference to the allowable cost of debt components. According to OPUC, the swap losses are not tied to SPS's actual cost of debt since the embedded (or actual) cost of debt, including interest rates, issuance costs, premiums, discounts, and refunding costs, is determined by market interest rates at the time of issuance. The swap instruments are separate contracts that a company enters into for the purpose of interest rate hedging. Interest rate swap losses are risk management costs, argues OPUC, not the costs mentioned in the Commission's cost of service rule.

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[243] SPS Ex. 39, Schell rebuttal at 21-22.

[244] *Application of AEP Texas Central Company for Financing Order,* Docket No. 39931, Financing Order at 16 (Jan. 12, 2012); *Application of Entergy Texas, Inc. for a Financing Order,* Docket No. 37247, Financing Order at 14-15 (Sept. 11, 2009).

[245] Docket No. 39931, Financing Order at 16. In Docket No. 37247, the utility did not seek approval of interest rate swaps but the Commission indicated that "the potential benefits of an interest-rate swap would not outweigh the costs of researching and preparing the swap and the potential risks to consumers . . . ." Docket No. 37247, Financing Order at 15.

SPS believes that the costs associated with the interest rate swap are an actual cost of debt, which SPS properly calculated according to the Commission's cost of service rule, 16 TAC § 25.231(c)(1)(C)(i), and the Commission's RFP. SPS contends that OPUC's position is contrary to the Commission's decision in a more recent rate case, where SWEPCO was allowed to recover the costs associated with an interest rate swap. In Docket No. 40443, the ALJs found that interest rate swaps are common in the capital intensive utility industry and were reasonable.[246] Moreover, SPS notes that two financing cases OPUC cites involved securitization and transition bonds, which are supported by pledges of the State of Texas and, therefore, have less market risk.[247]

From a ratepayers' perspective, OPUC's position on this issue is understandable. SPS's decision to lock interest rates did not benefit ratepayers. However, SPS witness Ms. Schell testified that, at the time of both swaps, there were indications interest rates would rise. Without the benefit of hindsight, it is difficult to find that SPS was unreasonable in its attempt to lock in interest rates and reduce cost volatility. Rather, the ALJs are persuaded that SPS made a reasonable attempt to provide interest rate certainty.

The ALJs do not find support for either SPS's or OPUC's arguments that the Commission's cost of service rule (and the RFP) support their respective positions. The rule does not include or exclude interest rate swaps. Neither does the Commission's RFP. However, OPUC's position that a rate interest swap is a separate contract and is not connected to the debt issuance fails to persuade the ALJs. The evidence shows that the rate interest swap is directly tied to SPS's debt issuance; SPS would not have executed an interest rate swap without the debt issuance. Thus, SPS's argument that the rate interest swap is a debt issuance cost is more persuasive.

Turning to case precedent, the ALJs find SPS has the better argument. The Commission's decisions in financing cases are not on point. But the Commission's decision in a

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[246] Docket No. 40443, PFD at 143.

[247] SPS Ex. 39, Schell rebuttal at 23.

similar rate case, Docket No. 40443, is directly applicable. In Docket No. 40443, the Commission allowed the utility to include interest rate swaps as part of its long-term debt. This precedent suggests that 16 TAC § 25.231(c)(1)(C)(i) and the Commission's RFP support the inclusion of interest rate management agreements as a part of a debt issuance.[248]

In conclusion, SPS offered some evidence that it sought to lock in interest rates before a large debt issuance in 2003 and 2006. At the time, there were indications that rates would rise; therefore, SPS's actions were not imprudent. The ALJs also note that Staff did not find SPS's actions in 2003 and 2006 to be unreasonable. The Commission has permitted interest rate swaps in another rate case, and the ALJs rely on this precedent in this rate case. Absent any evidence that SPS's actions were unreasonable, the ALJs recommend the adoption of SPS's calculated 5.98% cost of long-term debt.

D. Capital Structure

SPS's proposed cost of capital (8.28%) is based on a capital structure of 46.03% long-term debt and 53.97% common equity.[249]

Capital Component	Percentage	Cost	Weighted Cost
Long-Term Debt	46.03	5.98%	2.75%
Common Equity	53.97	10.25%	5.53%
			8.28%

SPS witness Ms. Schell testified that SPS's actual cost of capital (assuming Mr. Hevert's 10.25% return on equity) as of June 30, 2014, was 8.22%, which is six basis points lower than her recommended weighted cost of capital. On June 30, 2014, the equity ratio was 52.44% due to an SPS debt offering. In July 2014, Xcel Energy invested $60 million to rebalance SPS's capital structure. Ms. Schell indicated that SPS's equity ratio includes projected changes to the

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[248] The ALJs note that SPS did not proffer evidence that interest rate swaps are common in the industry, whereas in Docket No. 40443, such evidence was admitted and relied upon by the ALJs. *See* Docket No. 40433 PFD at 142-143.

[249] SPS Ex. 8, Schell direct at 29.

common equity balance for retained earnings. She testified that the 53.97% common equity ratio reflects the equity percentage that SPS will have when final rates go into effect. She also testified that, although this equity percentage is higher than SPS has had in the past, it is reasonable and necessary for SPS to have a strong equity ratio because of anticipated large capital expenditures from 2014 through 2018.[250]

TIEC and DOE propose different capital structures than SPS, which are discussed below.[251] Staff witness Ms. Winker testified that SPS's proposed capital structure is reasonable.[252]

1. TIEC's Recommendation

TIEC witness Mr. Gorman noted that a capital structure with too much common equity overstates a utility's revenue requirement and increases the rates of retail customers. He recommends that the Commission adopt a 50% equity and 50% debt structure. In his opinion, this capital structure is more consistent with the industry average common equity ratio and with his proxy group, which had an equity average and median of 51.7% and 50.1%, respectively.[253]

Mr. Gorman admitted that the Commission generally uses a vertically-integrated utility's actual capital structure if it is found to be reasonable. He acknowledged that the companies in his proxy group are utility holding companies, not a utility operating company, such as SPS. But Mr. Gorman found it appropriate to consider and compare SPS's capital structure to the capital structure of certain holding companies as one way of determining whether or not SPS's capital structure is reasonable. Mr. Gorman also indicated that interest rates have been very low, allowing utilities to borrow at attractive rates. Thus, particularly in this market, Mr. Gorman

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250 SPS Ex. 9, Schell direct at 29-30.

251 OPUC disagrees with SPS's proposed capital structure based on its treatment of interest rate swaps.

252 Staff Ex. 6A, Winker direct at 34. AXM witness Mr. Parcell compared SPS's and Xcel's common equity ratios and used the capital structure ratios proposed by SPS. AXM Ex. 4, Parcell direct at 15-16.

253 TIEC Ex. 4, Gorman direct at 11-12.

suggested it is unreasonable to propose a capital structure that relies too heavily on common equity capital. He concluded that his 50%/50% mix of debt and equity allows SPS to minimize its cost of capital while preserving its bond rating.[254]

SPS witness Ms. Schell disagreed with Mr. Gorman, claiming he erroneously relied on the capital structures of holding, not operating, utility companies. In her opinion, the operating company capital structure is a better measure of comparison because holding companies often include unregulated enterprises that can skew capital structures. She further noted that SPS witness Mr. Hevert's proxy group had an average equity percentage of 53.26%, which is within 71 basis points of SPS's requested equity percentage of 53.97%.[255]

Ms. Schell further disputed Mr. Gorman's analysis because SPS has projected capital expenditures to net plant that are far higher than any of the companies in Mr. Gorman's proxy group. The ratio of SPS's projected capital expenditures to net plant is 84%; whereas, the next closest company, Otter Tail Corporation, has a 59% ratio. Otter Tail Corporation's common equity ratio is 57.9%. Ms. Schell indicated that a high ratio of proposed capital expenditures to net plant translates to higher risk.[256]

TIEC argues that SPS's 53.97% common equity ratio ignores the high cost of equity compared to debt and the nation's current low interest rate. SPS counters that, if the opposite were true, that debt costs were high relative to historical standards, no one would argue for including less debt in the capital structure. SPS also notes that its customers are receiving the benefit of the lower cost of debt cost through reduced borrowing costs.

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[254] TIEC Ex. 4, Gorman direct at 13-14.; Tr. at 1,152-1,153, 1,217.

[255] SPS Ex. 9, Hevert direct, Att. RBH-RR-10.

[256] SPS Ex. 39, Schell rebuttal at 14.

2. DOE's Recommendation

DOE witness Ms. Reno recommends a capital structure that is composed of 51.98% equity, 44.96% long-term debt, and 3.06% short-term debt. Ms. Reno explained that short-term debt is the debt used to fund SPS's operations and investments. Although she admitted that the Commission generally does not include short-term debt in a utility's capital structure, Ms. Reno believes that it should be included because investors are concerned about interest. She observed that credit-rating analysts incorporate all interest-bearing debt in their ratings. Ms. Reno used SPS's actual embedded costs, as calculated by Ms. Schell, and SPS's actual short-term debt balances for the calendar year 2014 to reach her recommendation.[257]

SPS witness Ms. Schell testified it is misleading to state that SPS finances its operations and investments with short-term debt. She explained that SPS initially funds its capital investments with a combination of internally-generated funds, short-term debt, long-term debt, and common equity investments from its parent company, Xcel Energy. But the short-term debt initially used to fund operations and capital investments is converted to long-term debt, similar to when a utility asset is removed from construction work in progress (CWIP) and placed in service. Thus, according to Ms. Schell, SPS's long-term investments that are placed in service are financed with long-term debt and equity. Because SPS earns a return on the investment only after it has been placed in service, only the long-term debt used to finance that investment should be included in the capital structure.[258]

Ms. Schell also testified that Ms. Reno's recommended capital structure uses mismatched balances, which has the effect of driving the short-term debt balance higher. For equity and long-term debt, Ms. Reno used the balances as of December 31, 2014. But for short-term debt, she used the average annual balance for calendar year 2014, which is more than twice as high as the year-end balance. According to Ms. Schell, if Ms. Reno had used short-term debt balances as

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[257] DOE Ex. 1, Reno direct at 10.

[258] SPS Ex. 39, Schell rebuttal at 10.

of December 31, 2014 (consistent with the other balances), her recommended equity ratio (including the short-term debt) would have been 52.66%.[259]

SPS further disputes Ms. Reno's opinion because:

- In the last 20 years, the Commission has not required a utility to include short-term debt in its capital structure.[260] Nevertheless, Ms. Reno believes that investors are looking at the company's ability to pay back its interest-bearing debt, which includes short-term debt.[261]

- Although Ms. Reno stated that her reason for including short-term debt in SPS's capital structure was based on SPS funding its operations with such debt, she admitted that could not name any specific operation funded by short-term debt.[262]

- Ms. Reno also indicated that she included short-term debt because credit analysts incorporate all interest-bearing debt in their ratings. However, Ms. Schell noted that, while such analysts consider all forms of debt obligations, not all debts should be included in rate base or considered in ratemaking. For instance, if SPS had unregulated operations and assets, they would not be considered in a rate case.[263]

- Ms. Reno disagreed with analysts who assume short-term debt will be refinanced with long-term debt. Rather, she assumed that SPS would continue financing its plant in service by using short-term debt because she thought the Commission needed to preapprove any issuance of long-term debt.[264] She later learned that the Commission does not require such preapproval.[265]

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[259] SPS Ex. 39, Schell rebuttal at 12.

[260] SPS Ex. 39, Schell rebuttal at 12.

[261] Tr. at 548.

[262] Tr. at 494.

[263] Tr. at 497.

[264] *See* DOE Ex. 1, Reno direct at 10; Tr. at 495-496.

[265] Tr. at 496.

3. ALJs' Recommendation

Turning first to Ms. Reno's recommendation, the ALJs were not persuaded that SPS's proposed capital structure should be changed to reflect short-term debt. As Ms. Schell indicated, SPS does not finance its rate base investment with short-term debt so it should not be included in SPS's capital structure. Although Ms. Reno thought her use of SPS's short-term debt at the end of 2014 ($83 million) was a reasonable average from SPS's high of $241 million that year, the previous year's average short-term debt was only $32 million. Moreover, Ms. Reno did not use the Test Year average (half of 2013 and 2014), which would have resulted in a lower average amount.[266] Her explanation that she was using information that investors commonly rely upon was unpersuasive and failed to support her recommendation.

As to Mr. Gorman's recommendation, the ALJs are not persuaded that SPS's proposed capital structure is unreasonable. For the following reasons, the ALJs are convinced that SPS's proposed capital structure should be adopted:

- While SPS's 53.97% equity ratio is higher than the average common equity ratios for vertically integrated utilities from 2009 to 2015, it is well within the range of authorized common equity ratios.[267]
- Mr. Gorman's recommended 50% common equity ratio was based on the capital structures of holding companies, not operating companies.[268]
- SPS has a high rate of projected capital expenditures to net plant.[269]
- The Commission generally uses a vertically-integrated utility's actual capital structure.[270]

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266 *See* DOE Ex. 1, Reno direct at Att. MLR-2 at 3; Tr. 499-501.

267 SPS Ex. 40, Hevert rebuttal at 134.

268 SPS Ex. 40, Hevert rebuttal at 133.

269 SPS Ex. 39, Schell rebuttal at 14.

270 Tr. at 1,151.

- Staff witness Ms. Winker found SPS's proposed capital structure reasonable.[271]

Accordingly, the ALJs recommend use of SPS's proposed capital structure of 46.03% long-term debt and 53.97% common equity.

E. Overall Rate of Return

Based on the discussions set forth above, the ALJs recommend that the Commission adopt the following overall rate of return for SPS:

Component	Cost	Weighting	Weighted Cost
Debt	5.98%	46.03%	2.75%
Equity	9.70%	53.97%	5.24%
Total		100.00%	7.99%

VIII. OPERATION & MAINTENANCE EXPENSES

Before discussing O&M expenses, it is necessary to note that Xcel Energy Services Inc. (XES) is the service company subsidiary of Xcel Energy. XES supplies a number of services to Xcel Energy subsidiaries, including SPS.[272]

A. Payroll Expense

According to Jill H. Reed, Xcel Energy's compensation structure for all non-bargaining employees (all XES employees) is based upon external market data obtained from independent third-party surveys. Using these market data, Xcel Energy identifies the compensation rate for a given skill set, based upon the compensation that competing companies are paying for employees. Data are considered from a variety of surveys, including both utility and non-utility

[271] Staff Ex. 6A, Winker direct at 34.

[272] SPS Ex. 14, Schmidt-Petree direct at 44.

companies, and Xcel Energy uses the median of the survey data to determine the appropriate salary range for a position. After XES establishes its cash compensation levels, compensation is paid through different components: base salaries, an annual incentive plan, recognition payments, and long-term incentive compensation.[273]

SPS and XES employees include linemen, accountants, human resource specialists, engineers, protection system technicians, transmission operators, welders, chemists, call center representatives, technical instructors, pricing consultants, power traders, load forecasters, fleet mechanics, reliability analysts, compliance coordinators, and environmental analysts. Ms. Reed testified that providing market-competitive compensation is necessary to attract, retain, and motivate these employees, who in turn perform the work necessary to provide quality electric service to SPS's customers. SPS's payroll also includes expenses for its own and for XES employees.[274]

AXM, OPUC, State Agencies, and Commission Staff recommend disallowances to SPS's payroll expense relating to: (1) base salary increases for bargaining and non-bargaining employees; (2) overall payroll based on number of employees; (3) SPS's annual incentive plan; and (4) an incentive plan targeted at energy traders. SPS disagrees with all recommended disallowances.

1. Salary Increases

SPS witness Ms. Blair testified that she annualized the Test Year amount of SPS and XES employee wages by taking the three-month total of employee wages from April through June 2014 and multiplying it by four to arrive at an annual amount of employee wage expense as of the end of the Test Year. She chose that three-month period because it included both the Test Year bargaining employee wage increase, which occurred in November 2013, and the Test Year non-bargaining

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[273] SPS Ex. 29, Reed direct at 14-15. SPS is not requesting recovery of long-term incentive compensation costs.

[274] SPS Ex. 29, Reed direct at 16.

employee wage increase, which occurred in March 2014. The annualized adjustments increased labor costs by $5,088,752 (total company).[275]

Ms. Blair also made a PTYA for wage increases that SPS and XES employees will receive between the end of the Test Year and the date on which the rates set in this case take effect. According to Ms. Blair, bargaining employees likely will receive a wage increase as a result of labor contract negotiations and arbitration; therefore, SPS budgeted for a 3% wage increase, effective November 2014. As stated above, all XES employees are non-bargaining employees, and they received a 3% wage increase on March 15, 2015. Ms. Blair testified that these wage adjustments are known and measurable. They increased labor costs by $3,140,852 (total company).[276]

At the hearing, SPS witness Ms. Reed confirmed that SPS and the International Brotherhood of Electrical Workers Local Union 602 had not reached an agreement on a wage increase.[277] However, Ms. Reed testified that an agreement will be finalized and most certainly will include an annual base wage increase for the bargaining employees. She also stated that it is common for such an agreement, once finalized, to include retroactive wage increases.[278]

Both Mr. Carver (on behalf of AXM) and Ms. Ramas (on behalf of OPUC) took issue with Ms. Blair's PTYAs. They testified that wage increases for bargaining unit employees should be disallowed because the collective bargaining agreement between SPS and the bargaining employees is not final and fails to meet the standards for known and measurable changes. Both witnesses stated that, even if the 3% increase is "budgeted" by SPS, it is not known and measurable. [279]

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[275] SPS Ex. 37, Blair direct at 44-45.

[276] SPS Ex. 37, Blair direct at 45-46.

[277] Tr. at 704-705.

[278] SPS Ex. 25, Reed rebuttal at 25.

[279] AXM Ex. 5, Carter direct at 27-28; OPUC Ex. 1, Ramas direct at 19, DR-3, Sch. 2.

Ms. Ramas recommended the removal of $2,203,733 in labor expenses (total company), a payroll tax expense reduction of $157,126, and a reduction to 401K expenses in the amount of $49,918. Her adjustment removes the projected wage increases for the union employees.[280] Mr. Carver also recommended removal of the known 3.0% wage increase for the non-bargaining employees, which was effective on March 15, 2015. He testified this was an impermissible PTYA.[281]

The ALJs concur with Ms. Ramas and Mr. Carter that the non-finalized agreement for bargaining employees is not known and measurable. Although an agreement and wage increase with the bargaining employees is likely, the amount is not known and measurable. Thus, Ms. Ramas's recommendations should be adopted. However, the ALJs decline to adopt Mr. Carver's disallowance for the payroll increase for the non-bargaining employees. SPS's adjustment for the wage increase in effect on March 15, 2015, does meet the known and measurable test. Accordingly, those costs should be included in SPS's O&M costs.

2. Overall Payroll Expense

Staff witness Ms. Givens recommended an overall adjustment to SPS's payroll expense to reflect the decrease in the number of employees in the six months following the Test Year. Ms. Givens noted that the number of employees had decreased by 31 for SPS and 65 for XES from the end of the Test Year to December 31, 2014. She also stated that SPS did not explain the downward trend. Using the December 2014 numbers, Ms. Givens calculated a downward adjustment of $1,947,999 for SPS and $760,572 for XES.[282]

SPS witness Ms. Reed objected to Ms. Givens's recommendation. While she agreed it is objectively reasonable to use more up-to-date numbers, she noted that, as of May 31, 2015, the number of both SPS and XES employees had risen. The total numbers for June and

280 OPUC Ex. 1, Ramas direct at 19.

281 AXM Ex. 5, Carter direct at 27.

282 Staff Ex. 5A, Givens direct at 12-13.

December 2014 (which Ms. Givens had relied upon for her adjustment) were 4,841 and 4,745, respectively.[283] Ms. Reed also noted that the numbers of employees have increased beyond the June 2014 numbers. She testified that this pattern illustrates Xcel Energy's attrition rate, although it tries to remain competitive. In her opinion, the most recent numbers demonstrate that the Test Year level is representative of, if not lower than, the actual headcount experienced as of May 2015.[284]

The ALJs do not recommend a change to SPS's Test Year payroll expense based on a decrease in the number of employees. SPS has shown that the number of employees fluctuates and has increased since Ms. Givens made her recommendation.

3. Incentive Compensation

SPS requests recovery of several incentive compensation plans, which include expenses directly incurred by SPS and expenses allocated to SPS by XES. SPS's compensation plans—the Annual Incentive Plan (AIP), Xcel Wholesale Energy Marketing and Trading Supplemental Incentive Plan (SIP), and Spot On Award Recognition Program (Spot On)—and the contested issues relating to those plans are set out below.

a. Annual Incentive Plan

Ms. Reed testified that companies can provide cash compensation to employees either solely through base salary or through a combination of base salary and incentive compensation. Xcel Energy has chosen to have incentive compensation be a part of the employee's total compensation. According to Ms. Reed, it is only with the inclusion of this incentive compensation—the AIP—that Xcel Energy's compensation levels are competitive with other companies. SPS commissioned a study, the 2014 Towers Watson Compensation Study (Towers Watson Study), which indicated that 100% of energy companies maintain an annual incentive

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283 SPS Ex. 48, Reed rebuttal at 30-31.

284 SPS Ex. 48, Reed rebuttal at 31.

plan.[285] SPS contends that using incentive compensation: (1) provides incentives for employee performance; and (2) saves costs because incentive compensation is not a fixed, permanent cost. SPS recognizes that the Commission has disallowed incentive compensation expense associated with financial-based measures because they benefit shareholders, and not necessarily ratepayers.[286]

SPS contends that it removed all AIP expense associated with financial measures. Witnesses for AXM and OPUC disagreed and recommended removal of additional costs. Staff suggested a reduction to SPS's AIP costs from O&M expenses. The AIP expense and the objections to its inclusion are discussed below.

i. Background Information

Ms. Reed explained that the AIP covers exempt, non-bargaining employees in all states in which Xcel Energy operates. Each eligible employee has a set of performance objectives. The employee's target annual incentive compensation is expressed as a percentage of base salary. The percentage is determined by the employee's position within the organization and, when combined with the employee's base salary, delivers a market-competitive level of total cash compensation. The program uses the earnings per share of Xcel Energy as an affordability trigger for AIP payments. If the overall affordability trigger for payment is not met, the program does not pay any incentive compensation.[287]

The AIP is extensive and complicated. As mentioned above, if the overall affordability trigger is not met, no incentive compensation is paid. Ms. Reed explained that the amount of

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[285] The Towers Watson Study compared Xcel Energy's level of compensation to the median and average levels of compensation paid by the comparison groups. SPS Ex. 29, Reed direct at 43-44.

[286] SPS initial brief (RR) at 164, *citing Application of Oncor Electric Delivery Company for Authority to Change Rates*, Docket No. 35717, Order on Rehearing at FF 92 (Nov. 30, 2009). OPUC, in its initial brief (RR) at 37, also cited to a similar finding in Docket No. 39896, Order on Rehearing at FF 129.

[287] SPS Ex. 29, Reed direct at 26.

AIP an employee earns is dependent upon the achievement of the Corporate, Business Area, and Individual AIP performance goals:[288]

Performance Component	Types of Goals within Component	Purpose of Goals within Component
Individual	The individual component is based on the individual performance results of specific goals identified by the employee and his or her manager.	Goals are tied specifically to the employee's job functions and competencies and are developed in alignment with business area and corporate objectives.
Business Area	The business area component consists of goals and key performance indicators specific to the business area in which the employee works.	Goals are typically comprised of measures related to operational performance and are aligned to the corporate scorecard goals and priorities.
Corporate	The corporate component consists of goals and key performance indicators focused on operational, environmental, and safety measures.	Goals represent customer and employee interests.

The three components are not equally important, rather they are weighted based upon the employee's position and level of responsibility. For example, the weighting for non-supervisory employees focuses on the Individual and Business Area goals tied to customer satisfaction, safety, and reliability, and the weighting is specific to each job description. For example, a certain engineer's weighting may be 75% Individual, 15% Business Area, and 10% Corporate, while a different engineer may have a 50%, 30%, 20% weighting. In contrast, the weighting for more senior level positions focuses on Corporate goals. An actual AIP payment to an employee may exceed or fall below the target amount depending upon the employee's actual performance. The maximum payout is 150% of the target amount based on exceptional performance, and the minimum payout is 50% of the target. Performance below the 50% level results in no incentive compensation.[289]

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[288] SPS Ex. 29, Reed direct at 26-27.

[289] SPS Ex. 29, Reed direct at 27-28.

SPS witness Ms. Reed testified that SPS took steps to mitigate AIP costs. In 2011, non-exempt, non-bargaining employees who previously were included in the AIP at a 6% target payout percentage are no longer eligible. To ensure that non-exempt employees continued to be paid at market levels, their base wages were increased up to 3%. Xcel Energy also made other cost-saving changes to the design of the AIP program. Employees hired on or after October 1 of a program year are no longer eligible for that year's AIP because they will not have been in the job long enough. Another change is that incentive awards are prorated for employee job movement if it results in a change in incentive opportunity. Xcel Energy also added a provision that employees must be employed with Xcel Energy on the actual date the AIP is paid, meaning that employees who voluntarily leave the company will not receive an award if they leave before the payment date. Finally, Xcel Energy eliminated all incentive pay (not just the amount linked to individual performance) for any employee who was not performing at a successful level.[290]

SPS requests $5,202,078 (total company) of AIP expenses. This amount represents six months of target level expenses for the 2013 AIP year (July–December 2013) and six months of target level expenses for the 2014 AIP year (January–June 2014). SPS notes that AIP payments may exceed the target amount, as they did in 2013, when certain goals were exceeded. SPS is not, however, requesting recovery of the portion of AIP expense that exceeded the target level, and it adjusted the Test Year revenue requirement to remove the dollar amount of annual incentive compensation expense above the target level of expense, reducing O&M expenses by $1,302,415 (total company).[291]

Because the Commission has previously excluded incentive pay related to financial goals, Ms. Reed reviewed the Corporate and Business Area AIP scorecards for 2013 and 2014 to identify and remove costs associated with financial-based components. For example, she removed costs associated with the O&M growth management key performance indicator for 2014. She also removed the percentage of costs associated with financial-based goals in nine

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[290] SPS Ex. 29, Reed direct at 37.

[291] SPS Ex. 29, Reed direct at 36-37.

business areas. These adjustments decreased AIP costs by $959,219 (total company).[292] Ms. Reed calculated the operational- and financial-based incentive percentages of the target level incentive amounts for both SPS and XES:[293]

SPS

Year	Operational	Financial
2013	94.0%	6.0%
2014	88.8%	11.2%

XES

Year	Operational	Financial
2013	95.0%	5.0%
2014	82.1%	17.9%

Ms. Reed also testified that, even with providing market-competitive compensation, SPS and XES are experiencing a relatively high level of attrition. She believes that the attrition is due to: (1) the market's need for the specific skills and training; (2) growth in the oil and gas industries; (3) the overall improvement of the economy; and (4) work force retirements. SPS projects that approximately 50% of Xcel Energy's (which includes both SPS and XES) current workforce will retire in the next 10 years. Attrition rates for the two companies are found below:[294]

Attrition Rates

	2010	2011	2012	2013	2014 (through September 30)	Projected 2014
SPS	6.5%	8.4%	5.8%	7.5%	5.6%	6.8%
XES	6.9%	6.5%	7.8%	9.8%	12.2%	9.8%

292 SPS Ex. 29, Reed direct at 33-36, 38-39.

293 SPS Ex. 29, Reed direct at 38.

294 SPS Ex. 29, Reed direct at 16-17.

ii. AXM and OPUC Recommended Adjustment

AXM witness Mr. Carver proposed removal of Test Year expenses related to the AIP. AXM argues that the Commission should only permit recovery of the cost of incentive plan metrics reasonably identifiable with customer service, employee safety, cost reduction, individual employee performance, or operational achievements or efficiencies. Mr. Carver testified that, when Xcel Energy restructured the AIP in 2012, the entire incentive plan was shifted from a mix of financial and non-financial metrics to a financial-based plan that has a pre-condition—the earnings-per-share affordability trigger, which must be reached before any employee is paid. According to Mr. Carver, the performance of each employee only determines that employee's level of participation. A payout and the amount of payout are determined by the consolidated earnings per share. Thus, Mr. Carver concludes that the entire AIP expense is financially-based.[295]

OPUC argues that SPS's removal of 17.9% of XES and 11.2% of SPS's AIP expenses (which SPS removed because it determined these amounts were financially-based) is inadequate. According to Ms. Ramas, the main driver of the plan is achieving a minimum earning per share for Xcel Energy's shareholders. She noted the earnings-per-share amount has increased every year of the program:[296]

Year	EPS Requirement	Actual EPS
2009	$ 1.45	$ 1.50
2010	$ 1.55	$ 1.62
2011	$ 1.65	$ 1.72
2012	$ 1.75	$ 1.82
2013	$ 1.85	$ 1.95
2014	$ 1.90	$ 2.03

295 AXM Ex. 5, Carver direct at 34.

296 OPUC Ex. 1, Ramas direct at 23-24.

Ms. Ramas further suggested that employees are aware that they may not receive compensation unless the trigger is met, which shifts their focus to ensure the financial requirement is met. She concluded that the AIP benefits shareholders and is financial-based incentive compensation. Accordingly, she recommended a 50/50 split between ratepayers and shareholders of the AIP costs before consideration of the individual components of the AIP goals. She then recommended that the 17.9% XES factor and the 11.2% SPS factor be applied to the remaining 50% of the incentive costs.[297]

SPS argues that Mr. Carver and Ms. Ramas ignore the design of the AIP and the operational-based measures. Instead, they concentrate solely on the earnings-per-share affordability trigger. SPS witness Ms. Reed testified that certain goals are directly connected to operations and benefit customers. For instance, she noted the following goals:[298]

- *Operational Excellence*. Relates to the System Average Interruption Duration Index and the Unplanned Outage Rate, which measure the average annual duration of sustained interruptions and percentage of time when generating plants are not available due to unplanned outages, respectively.
- *Value to Customers*. Based upon the public safety index, measuring response time to calls for electric service.
- *Employee Safety and Engagement*. Relates to the recordable incident rate to the Occupational Safety and Health Administration.

Ms. Reed reiterated that the design of the AIP requires performance of operational-based measures and benefits customers. She disagreed that the focus of employees is shifted to the earnings per share as opposed to an operational-based performance measure, and relied upon her management experience at SPS. She testified that the employees she has managed over the years are generally focused on their individual performance and goals, not the affordability trigger.

[297] OPUC Ex. 1, Ramas direct at 24-25. These factors are based on the percentages of financial-based goals, which are found in the tables provided by Ms. Reed and noted above in the PFD.

[298] SPS Ex. 48, Reed rebuttal at 16.

Ms. Reed also testified that, without the AIP portion of compensation, SPS's and XES's total case compensation would be below the market rate.[299]

iii. Staff Recommended Adjustment

Staff witness Ms. Givens recommended a downward adjustment of $444,899 to remove the portion of compensation that exceeds 25% of an individual's base salary. This adjustment applies to SPS employees categorized as Executives (one employee) and XES employees categorized as Grade X, Business Area Vice President, and Executives (2, 21, and 10 employees respectively). Ms. Givens was concerned that the AIP was excessive for these employees. For example, the XES executives eligible for the AIP during the Test Year received an award averaging $249,363. She indicated that the AIP can be a reasonable salary supplement but some control must be maintained. Thus, she recommended disallowance of any amount over 25% of base salary.[300]

Ms. Givens testified that other XES jurisdictions include a cap on incentive compensation. For instance, Minnesota limits payouts with a 25% cap; North Dakota limits payouts with a 15% to 25% cap; South Dakota limits with a 25% cap; and Wisconsin allows only 50% recovery. In her opinion, it is reasonable to level the playing field for Texas ratepayers by placing a cap on SPS's ability to recover excessive AIP payments.[301] Staff argues that annual incentive compensation caps in other jurisdictions provide guidance as to reasonableness. Based on those caps, Staff contends that Ms. Givens's proposed adjustment is reasonable.

SPS witness Ms. Reed disagreed. She noted that Xcel Energy applies a comprehensive process to ensure cash compensation is comparable to the market. She cited the Towers Watson Study for further support that these higher-salaried employees are paid amounts comparable to the market. She also noted that the facts and circumstances in different rate cases in different

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299 SPS Ex. 48, Reed rebuttal at 13, 22; Tr. at 703.

300 Staff Ex. 5A, Givens direct at 18-19.

301 Staff Ex. 5A, Givens direct at 20-21.

operating companies' jurisdictions should not apply here, particularly since there is no evidence that the incentive compensation is excessive when compared to the market. Ms. Reed pointed out that SPS has already removed AIP expense above the target level.[302]

iv. ALJs' Analysis

As SPS acknowledged, the Commission has determined that Texas ratepayers should not be responsible for an incentive plan that is related to financial metrics unless Texas ratepayers benefit from the achievement of incentive targets. The question is whether SPS proved it properly excluded the portions of the AIP that relate to financial metrics (OPUC suggests they did not) or whether (as AXM contends) the entire plan is designed to reward XES and SPS employees for achieving financially-based goals.

The ALJs are persuaded that SPS adequately excluded the portion of the AIP related to financial metrics. The ALJs find that the earnings-per-share trigger is indicative of sound fiscal policy: if Xcel Energy fails to meet its specific goal, the AIP is not paid. Although the AIP trigger has a financial component, an employee must demonstrate that he or she is effective at the employee's specific performance in order to receive the incentive compensation. The ALJs found Ms. Reed's testimony convincing that employees are focused on whether they meet their own specific performance goals, not on the affordability trigger, which they cannot individually affect. An employee who fails to meet his or her specific performance goal will not receive the incentive pay regardless of the affordability trigger.

SPS also put forth evidence that it is necessary to pay employees compensation that is market-competitive. The AIP is combined with employee base pay and, except for Staff's objections to the excessive amounts of certain employees' AIP, there was no evidence that overall base pay plus the AIP was excessive when compared to the Towers Watson Study. In fact, the study indicated that without the AIP, cash compensation was no longer

[302] SPS Ex. 48, Reed rebuttal at 32-34.

market-competitive.[303] The ALJs find sufficient evidence that a portion of the AIP expenses that SPS seeks to recover includes incentives for non-financial objectives and properly rewards employees for achieving increased productivity, which benefits Texas ratepayers.

Turning to Staff's recommendation, the ALJs find it reasonable to adjust the amount of AIP which exceeds 25% of an individual's base salary. The ALJs acknowledge that the Towers Watson Study provided overall support for SPS's and XES's cash and incentive compensation. However, as Ms. Givens testified, other jurisdictions contain salary caps and the amounts of incentive compensation are, on their face, excessive. The ALJs gave weight to Ms. Givens's experience on this issue and recommend an adjustment of $444,899 to the appropriate FERC account as well as an adjustment to remove the Medicare portion of payroll taxes in FERC Account 408 (an adjustment of $6,451).[304]

b. Supplemental Incentive Plan

Ms. Reed testified that the Xcel Energy SIP is designed to provide eligible employees who work in wholesale energy trading activities with competitive compensation, consistent with compensation practices in the wholesale energy trading sector. The program is a supplement to the AIP and is part of the total cash compensation offered to Xcel Energy wholesale energy trading employees. The incentives are based on the wholesale energy trading profit margins; a large percentage of these margins (55%) is shared with customers through the fuel factor. SPS requests $368,292 (total company) for these expenses. According to Ms. Reed, the SIP creates an incentive for the eligible wholesale energy trading employees, which in turn increases the amount of margins shared with customers. Thus, the benefits for customers are immediate and directly flow from the SIP.[305]

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303 SPS Ex. 29A, Towers Watson Study (confidential) at C-11, C-12.

304 *See* Staff Ex. 5A, Givens direct at 20-21, Att. AG-8 at 93-94.

305 SPS Ex. 29, Reed direct at 41; SPS Ex. 48, Reed rebuttal at 35.

Staff witness Ms. Givens recommends the removal of the SIP incentive from payroll because it is a financially-based incentive program. Moreover, she noted that SPS currently includes $1,004,005 of Test Year costs associated with the proprietary trading function in its revenue requirement, and these costs are in addition to the SIP costs. Plus, employees that are eligible for SIP are also eligible for the AIP. Ms. Givens recommended removal of $368,292 related to the SIP and a corresponding adjustment of 7.65% to payroll taxes, which results in a payroll tax adjustment (decrease) of $28,174.[306]

Again, the ALJs are persuaded by the testimony of Ms. Givens that the additional incentive for wholesale energy traders is not reasonably necessary to provide electric service. This is because the SIP provides an incentive over and above the AIP.[307] Moreover, although both shareholders and ratepayers benefit from higher profit margins gained from energy trades, 45% of the profit margins is allocated to shareholders. The ALJs recommend adoption of Ms. Givens's adjustments to remove these costs from SPS's payroll.

c. Spot On Award Recognition Program

Ms. Reed explained that, in 2011, Xcel Energy removed non-exempt, non-bargaining employees (*i.e.*, the hourly employees such as administrative assistants, clerical staff, and call center staff) from participation in the AIP. In connection with that change, Xcel Energy implemented Spot On, which allows managers to reward non-exempt, non-bargaining employees for outstanding performance close to the time when the employee has made the contribution. SPS requests $80,138 (total company) for Spot On.[308]

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[306] Staff Ex. 5A, Givens direct at 22-23; Staff Ex. 5C, Givens (confidential) at 22-23. The ALJs find further support for Ms. Givens's recommendation in the confidential portion of her testimony. Ms. Givens was also concerned with how the program operates and its variability from year to year.

[307] The Towers Watson Study did not compare the additional SIP incentive; it was limited to the AIP. *See* SPS Ex. 29A, Towers Watson Study (confidential).

[308] SPS Ex. 29, Reed direct at 42.

No party took issue with SPS's inclusion of Spot On expenses. Accordingly, they should be included in O&M.

B. Pension and Related Benefits

PURA § 36.065(a) provides that the Commission "shall include in the rates of an electric utility expenses for pension and other postemployment benefits, as determined by actuarial or other similar studies in accordance with generally accepted accounting principles, in an amount the [Commission] finds reasonable." SPS witness Mr. Schrubbe testified that, in addition to cash compensation, SPS offers the following non-cash benefits to its employees: (1) pension and other post-employment and retirement benefits;[309] (2) active health and welfare benefits, which include medical, dental, pharmaceutical, vision, life insurance, and other miscellaneous benefits; (3) workers' compensation benefits, including both self-insured and third-party-insured benefits; and (4) other types of benefits, including a 401(k) defined contribution plan and certain types of deferred compensation.[310] SPS is seeking recovery of the following expenses:[311]

Total Company Pension and Benefits (in $)			
Benefit	**Test Year (12 months ended June 2014)**	**Known and Measurable Adjustment**	**Adjusted Test Year**
Qualified Pension	16,202,277		16,202,277
Nonqualified Pension	558,068		558,068
FAS 106 Retiree Medical	250,653		250,653
FAS 112 Long-Term Disability (Self-Insured)	37,835		37,835

309 Pension and retirement benefits include a pension plan, pension restoration benefit, retiree medical plan, and long-term disability benefits. SPS Ex. 30, Schrubbe direct at 12.

310 SPS Ex. 30, Schrubbe direct at 12.

311 SPS Ex. 30, Schrubbe direct at 13.

Total Company Pension and Benefits (in $)			
Benefit	**Test Year (12 months ended June 2014)**	**Known and Measurable Adjustment**	**Adjusted Test Year**
Active Health Care[312]	13,684,322	670,602	14,354,924
Long-Term Disability (Third-Party-Insured)	576,777		576,777
Life Insurance	144,593		144,593
Miscellaneous Benefit Programs and Costs	635,854		635,854
401(k) Match	2,559,979	108,166	2,668,145
Miscellaneous Retirement-Related Costs	243,704		243,704
Workers Compensation (Self-Insured)	(271,725)	271,725	0
Workers Compensation (Third-Party-Insured)	1,147,796		1,147,796
Total Pension and Benefits Expense	**35,770,133**	**1,050,493**	**36,820,626**[313]

For the most part, the above expenses are not contested. Issues raised by Staff and Intervenors are discussed below.

1. Active Health Care and Welfare Expense

a. Active Health Care

SPS witness Mr. Schrubbe stated that SPS's Test Year active health care expense was $13,814,106 (total company).[314] SPS also requested an adjustment to increase that amount by

312 The per book amount for active health care in the cost of service is $13,212,986. Mr. Schrubbe indicated that this amount is an estimate and should be adjusted to reflect health care claims that were incurred near the end of the Test Year but not reported until after the Test Year. Adding the incurred-but-not-reported amount, which is $471,336, to the per book amount creates an actual Test Year amount of $13,684,322. The $1,141,938 adjustment to the per book amount in the cost of service is a combination of the incurred-but-not-reported adjustment and the $607,602 known and measurable adjustment. SPS Ex. 30, Schrubbe direct at 13.

313 SPS is also requesting recovery of $3,583,510 of deferred pension and other OPEB, which is discussed below in Section VIII.C.

314 In his direct testimony, Mr. Schrubbe listed the amount as $13,684,322; however, this amount was incorrect. SPS Ex. 49, Schrubbe rebuttal at 56.

$540,820 (total company) to reflect a 7% annual increase in active health care costs projected by SPS's external actuaries, Towers Watson, and by an independent consultant, PricewaterhouseCoopers.[315] However, after AXM and Staff took issue with SPS's proposed adjustment, SPS proposed using its actual amount of 2014 active health and welfare expenses, which was $14,117,064.[316]

AXM witness Mr. Carver testified that SPS's adjusted Test Year expense was well above historical levels. He recommended disallowance of SPS's entire upwards adjustment, finding that SPS had not demonstrated that the 7% adjustment was necessary or warranted.[317] AXM continues to recommend that SPS's PTYA be denied because SPS failed to provide detailed evidence that a higher number is more appropriate or that the health care expense should be based on calendar 2014 instead of Test Year amounts.

SPS argues that the adjustment should be allowed because: (1) the calendar year 2014 actual amount of active health care expense is similar to the adjusted Test Year amount of active health care expense; and (2) using the actual amount of calendar year 2014 active health care expense is consistent with Mr. Carver's recommendation that the Commission use the actual 2014 amounts for qualified pension expense and retiree medical expense (discussed below). According to SPS, the use of actual calendar year 2014 amounts is appropriate for qualified pension expense and retiree medical expense and also appropriate for active health care expense.

The ALJs recommend the use of SPS's actual amount of 2014 active health care expense, which was $14,117,064 (total company). SPS proffered sufficient evidence that medical costs were rising, although its initial adjustment was too high. The use of actual health care expense provides more certainty. Adopting SPS's rebuttal proposal to use actual 2014 calendar year active health care expense amounts will result in a disallowance of $237,859 (total company) from SPS's initial requested amount of active health care expense.

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[315] SPS Ex. 30, Schrubbe direct at 29-31.

[316] SPS Ex. 49, Schrubbe rebuttal at 56-57.

[317] AXM Ex. 5, Carver direct at 44-45.

Staff witness Ms. Givens proposed that SPS's active health care expense be reduced by approximately $350,000 (total company) to account for the declining number of SPS and XES employees. Because the ALJs decline to adopt Ms. Givens's adjustment, it would be inappropriate to reduce active health care expense. The ALJs conclude that SPS's active health care expenses should be reduced by only $237,859.

b. Other Types of Active Health and Welfare Expenses

In addition to the active health care expense, SPS requests recovery of the following amounts of active health and welfare expenses:

- $576,777 (total company) for long-term, third-party-insured disability coverage;
- $144,593 (total company) in life insurance costs; and
- $635,854 (total company) for miscellaneous benefit programs.

SPS presented testimony that these costs are reasonable and necessary for SPS to attract and retain qualified employees. No party has challenged the amounts, reasonableness, or necessity of the costs. Therefore, the ALJs recommend that they be included in the cost of service.

2. Qualified Pension

Staff witness Ms. Givens explained that SPS offers a defined benefit qualified pension plan upon retirement. There are two plans, and the eligible employee's hiring date determines which one applies. Ms. Givens stated that SPS uses the FAS 87 accounting standard to account for both plans. Towers Watson provides the amount that Xcel Energy needs to expense each year.[318] SPS initially requested $16,202,277 (total company) of qualified pension expense to be included in the cost of service. SPS calculated the Test Year amount by taking the sum of:

[318] Staff Ex. 5A, Givens direct at 26; SPS Ex. 30, Schrubbe direct at 12.

(1) half of the actuarially determined qualified pension expense for calendar year 2013, and (2) half of the actuarially determined qualified pension expense for calendar year 2014.[319]

AXM, OPUC, and Staff urge the Commission to make known and measurable changes to SPS's requested amount. AXM witness Mr. Carver recommended that the Test Year amount be adjusted to recognize a full year, not just six months, of an actuarial study by Towers Watson. His proposed adjustment would reduce the amount of qualified pension expense by $1,894,131 (total company). Mr. Carver testified that the adjustment is appropriate because: (1) the results of the 2014 Towers Watson actuarial study and FAS 106 related to 2014 operations were known and measurable; (2) it is appropriate to recognize these changes to be consistent with other adjustments; and (3) the 2015 study included other updates impacting pension costs, and SPS has not yet determined their impact.[320]

OPUC and Staff witnesses also proposed a known and measurable adjustment to the Test Year qualified pension expense, but they ask the Commission to use the more recent actuarial report, calendar year 2015. Substituting the 2015 amount for the Test Year amount would reduce qualified pension cost by $1,107,220 (total company).[321]

SPS witness Mr. Schrubbe agrees that it would be reasonable to use either the calendar year 2014 or 2015 actuarial report to establish the amount of qualified pension expense to be included in the cost of service. But he suggested that the 2014 actuarial report is a closer match

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[319] SPS Ex. 37, Blair direct at 61.

[320] AXM Ex. 5, Carver direct at 48.

[321] OPUC Ex. 1, Ramas direct at 28-29; Staff Ex. 5A, Givens direct at 27-28.

with the Test Year. He also noted that the 2015 actuarial report verified that the increases attributable to the 2014 mortality table update have been offset to some extent by other factors.[322]

The ALJs recommend the use of the 2014 actuarial report to establish the amount of qualified pension expense. While the 2015 report is more recent, the ALJs concur with Mr. Carver that the 2014 report has the possible benefit of matching other adjustments in this rate case. Thus, the ALJs would reduce the amount of qualified pension O&M expense by $1,894,131 (total company).

3. Non-Qualified Pension (and Other Post-Retirement Benefits)

In direct testimony, SPS requested recovery of $558,068 (total company) for non-qualified pension expense. In rebuttal testimony, SPS decided not to pursue recovery of the non-qualified pension expense and therefore withdrew its request to include the $558,068 in the cost of service. Accordingly, non-qualified pension expense is no longer an issue in this case.

4. FAS 106 Retiree Medical Costs

Concerning SPS's requested retiree medical costs, the contested issue is the same issue concerning qualified pension expense, discussed above. AXM, Staff, and OPUC suggest that SPS update its expenses based on newer actuarial studies.

SPS initially requested recovery of $250,653 (total company) for retiree medical expense, calculated under FAS 106. As with the qualified pension expense, SPS calculated the Test Year

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[322] SPS Ex. 49, Schrubbe rebuttal at 52. SPS agrees that it would be reasonable to use the calendar year 2014 actuarial report to establish the amount of qualified pension expense to be included in the cost of service. Mr. Schrubbe indicated that, when SPS filed its initial application, it was unclear whether updated mortality tables issued by the Society of Actuaries in 2014 would cause the qualified pension expense to rise significantly in 2015. Therefore, SPS did not seek to replace the Test Year amounts with the calendar year 2014 amounts. SPS Ex. 30, Schrubbe direct at 22-23. SPS's external actuaries subsequently concluded, however, that any pension cost increases resulting from the new mortality tables are likely to be largely offset by elements of annual pension cost that are declining. As there is more certainty with two actuarial studies, SPS finds it appropriate to include the calendar year 2014 qualified pension amount in the cost of service. SPS initial brief (RR) at 177.

amount of these costs by using half of the 2013 actuarially determined FAS 106 expense and half of the 2014 actuarially determined FAS 106 expense.[323] SPS notes that no party challenges its right to recover the FAS 106 expenses.

However, as for the qualified pension expense, AXM witness Mr. Carver recommended a known and measurable adjustment to use the amount of FAS 106 retiree medical expense found in SPS's 2014 actuarial report, which is $173,864 (total company).[324] Staff witness Ms. Givens and OPUC witness Ms. Ramas also proposed a known and measurable adjustment to retiree medical expense, but similar to qualified pension expense, they recommended that the Commission include in the cost of service the FAS 106 expense from SPS's 2015 actuarial report.[325]

Similar to its position on qualified pension expense, SPS does not object to the proposals to replace the initially requested Test Year amount of retiree medical expense with the actuarially determined retiree medical expense for 2014 or 2015.[326] The ALJs recommend the use of the 2014 actuarial amount for the same reasons stated above. Accordingly, the ALJs recommend adoption of the adjustment proposed by Mr. Carver, $173,864, which SPS used in its proposed rebuttal cost of service.

5. Stock Equivalent Plan

Xcel Energy has a Stock Equivalent Plan that it provides to non-employee members of the Xcel Energy Board of Directors. Xcel Energy, a Minnesota corporation, is required to have a board of directors pursuant to Minnesota state law.[327] SPS contends the Stock Equivalent Plan is

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[323] SPS Ex. 30, Schrubbe direct at 25.

[324] AXM Ex. 5, Carver direct at 47-48, Att. SSC-3 at C-19.

[325] OPUC Ex. 1, Ramas direct at 44; Staff Ex. 5A, Givens direct at 26-27.

[326] SPS initial brief (RR) at 180.

[327] SPS Ex. 48, Reed rebuttal at 28. Ms. Reed cites to Section 302A.201, Subd. 1, Minnesota Statutes.

market-competitive compensation that is a necessary expense and that paying compensation to the Board of Directors for the work they perform is reasonable.

SPS also argues that the amount of compensation is reasonable. Ms. Reed testified that Xcel Energy establishes the Board of Directors's compensation by using market data for the boards of directors for 23 other utilities. The market assessment is performed by an external independent consulting firm, Meridian Compensation Partners. The compensation is provided to Xcel Energy's Board of Directors in two components: (1) a retainer, which the director can choose to have paid as cash, deferred stock equivalent units, or a combination of the two; and (2) the Stock Equivalent Plan. A portion of the Stock Equivalent Plan is allocated to SPS, as well as the other Xcel Energy Operating Companies.[328]

For the Test Year, the total XES Stock Equivalent Plan payment was $1,350,000, with $163,701 or 12.14% allocated to SPS. OPUC witness Ms. Ramas recommended that these costs be excluded from O&M expenses because they focus on shareholder interests.[329] OPUC contends the plan is a discretionary benefit and redundant of other benefits board members receive. Further, OPUC contends that these costs are similar to financial-based incentive compensation and non-qualified post-retirement benefits, which should be disallowed because the benefits of these expenses flow through to shareholders.

SPS responds by noting that no party or record evidence refutes that: (1) having the Board of Directors is a requirement under Minnesota law; (2) the compensation for the Board of Directors is necessary; and (3) the Stock Equivalent Plan is a reasonable component of compensation that is consistent with compensation best practices.

The Commission's cost of service rule provides that only expenses that are reasonable and necessary to provide service to the public are eligible to be included in allowable

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[328] SPS Ex. 48, Reed rebuttal at 28-29.

[329] OPUC Ex. 1, Ramas direct at 32-33.

expenses.[330] An allowable O&M expense is one that an electric utility "incurred in furnishing normal electric utility service and in maintaining electric utility plant used by and useful to the electric utility in providing such service to the public."[331] The ALJs are not persuaded that the Xcel Energy Stock Equivalent Plan is necessary to the cost of providing electric service. Accordingly, the ALJs concur with OPUC that Stock Equivalent Plan expenses should be removed from SPS's O&M expenses.

6. FAS 112 Costs

SPS requests recovery of $37,835 (total company) in self-insured workers' compensation benefits calculated under FAS 112. No party took issue with either the request to include the FAS 112 costs in the cost of service or the Test Year amount of these costs. Thus, SPS's cost of service should include $37,835 (total company) of FAS 112 costs.

7. Executive Perquisites

SPS initially requested $3,565 (total company) of O&M expense for benefits to Xcel Energy executives, including financial counseling and physical examinations. Staff recommends that this expense be removed from the cost of service.[332] Although SPS believes that the benefits are reasonable, market-competitive benefits, it has removed the amount from its requested cost of service.

8. Moving and Relocation Expenses

SPS provides employees with moving and relocation expenses in order to be competitive and attract employees. SPS requests $634,765 in moving allowances and relocation fees for XES and SPS employees. Staff witness Ms. Givens recommended a downward adjustment. She

330 16 TAC § 25.231(b).

331 16 TAC § 25.231(b)(1)(A).

332 SPS Ex. 48, Reed rebuttal at 40.

indicated that SPS already offers a competitive compensation package and the amount requested was above moving allowances and relocation fees incurred by other vertically integrated electric utilities in Texas. In fact, Ms. Givens found that expenses for SPS increased significantly over time (from December 31, 2007, to the Test Year ending June 30, 2014) and are the highest for any similarly situated Texas utility. She also noted that SPS's calendar year 2013 and 2014 expenses were less than the Test Year's:[333]

Moving and Relocation Expenses

	2013	2014	Test Year
SPS	$450,703	$362,093	$397,716
XES	$172,784	$207,922	$237,049
Total	$623,487	$570,015	$634,765

Ms. Givens suggested a moving expense of $436,723, to align SPS with other similarly situated electric utilities (Test Year request $634,765 - $198,042 = $436,723).[334]

SPS takes issue with Ms. Givens's recommendation because it was based on the amount of expense that the Commission approved for ETI in a rate case with a 2011 test year.[335] SPS contends that Ms. Givens failed to justify any disallowance of moving and relocation expense. However, SPS argues that, if a disallowance should be implemented, the Commission should reject Ms. Givens's use of ETI's costs as the basis for the $198,042 disallowance she recommends. Instead, the Commission should look at SPS's actual moving and relocation expense incurred during calendar years 2013 and 2014, which were $623,487 and $570,015, respectively. SPS witness Ms. Reed testified that the average amount for the two years was $596,751. If the Commission believes an adjustment is needed, SPS recommends that it be

[333] Staff Ex. 5A, Givens direct at 23-25, 106-107.

[334] Staff Ex. 5A, Givens direct at 24.

[335] Docket No. 39896, Order on Rehearing.

allowed to include $596,751 in cost of service, or a reduction of $37,984 from the Test Year amount.[336]

The ALJs agree with Staff that SPS's moving and relocation expenses are high when compared to other reasonably situated utilities, even after taking into account that Staff's comparisons go back a few years. But Ms. Givens's suggested disallowance simply uses an amount from ETI's rate case, with no comparison to SPS (for instance, a comparison based on the number of employees). Therefore, the ALJs agree with SPS that basing an adjustment on the two years of SPS actual expense is more reasonable than using the costs ETI incurred in its 2011 test year. Accordingly, the ALJs recommend a disallowance of $37,984 from SPS's Test Year amount of moving and relocation expenses.

C. Deferred Pension and Other Post-Employment Benefits Expense

PURA § 36.065(b) allows a utility to establish a reserve account to record the difference between the annual amount of pension and OPEB expense approved in the utility's last general rate case, and the annual amount of pension and OPEB expense that the utility actually incurs. If the amount of pension and OPEB expense in the utility's approved rates is greater than the actual expense, the utility will have a surplus in its reserve account. If the amount of pension and OPEB expense in the utility's approved rates is less than the actual expense, the utility will have a shortage in its reserve account.[337]

PURA § 36.065(d) states that if a reserve account for pension and OPEB expense is established, the Commission, at a subsequent general rate proceeding shall:

(1) review the amounts recorded to the reserve account to determine whether the amounts are reasonable expenses;

336 SPS Ex. 48, Reed rebuttal at 38.

337 PURA § 36.065(b), (c).

(2) determine whether the reserve account has a surplus or shortage under PURA § 36.065(c); and

(3) subtract any surplus from or add any shortage to the electric utility's rate base with the surplus or shortage amortized over a reasonable time.[338]

In SPS's last base rate case, Docket No. 42004, the parties entered into a non-unanimous stipulation, which the Commission approved.[339] One of the provisions of the Commission's order addresses the recovery of the pension and OPEB tracker amount that had accrued by May 31, 2014:

> Recovery of the deferred pension and OPEB tracker amounts of $6,690,007 are included in the base rate increase reflected in Section I of this Stipulation and will be amortized over a three-year period beginning on June 1, 2014. These amounts consist of $3,468,975 deferred in 2013 and $196,032 deferred in 2014, plus $3,025,000 of unamortized pension and OPEB amounts (the balance as of May 31, 2014) from Docket No. 40824 (Finding of Fact No. 19.b.). If SPS files for rate relief before the end of the three-year amortization period, it may include any unamortized pension and OPEB balances in its request for relief.[340]

Based on the parties' agreement in Docket No. 42004 and subsequent events, SPS is requesting recovery in this case of $3,583,510 of deferred pension and OPEB benefits for the Texas retail jurisdiction. SPS witness Mr. Schrubbe testified that cost is composed of two pieces. The first piece represents the unamortized balance of the pension and OPEB amounts deferred through July 1, 2015, which is $4,274,171. That amount reflects accruals in excess of the agreed-upon baselines set in Docket Nos. 38147, 40824, and 42004. The second piece represents the total deferrals for June through December of 2014, which add to $(690,662). The negative amount reflects accruals of additional expense in order to reflect expense at the baseline set in Docket No. 42004. SPS witness Ms. Blair included $3,583,510 of deferred pension and

[338] PURA § 36.054(d).

[339] Docket No. 42004, Order.

[340] Docket No. 42004, Order FF 24.

OPEB ($4,274,171 + $(690,662) = $3,585,510) under FERC Account 92603. SPS is proposing a one-year amortization of that amount.[341]

SPS notes that no party has taken issue with the amount of the pension and OPEB tracker. However, AXM witness Mr. Carter recommended that the deferred pension and OPEB balance be amortized over a two-year period, and OPUC witness Ms. Ramas proposed a three-year amortization period. Both witnesses suggested that a longer period is appropriate because: (1) there is a large amount of deferred expense; (2) it is uncertain how long the rates set in this case will remain in effect; (3) a longer period would mitigate the rate impact on customers; and (4) a one-year amortization period may allow SPS to over-recover its costs.[342] AXM notes that the two-year amortization proposed by Mr. Carver is a continuation of the three-year amortization that the parties, including SPS, agreed to in Docket No. 42004.

SPS argues that its witness, Mr. Evans, testified that SPS expects to file another base rate case within a year. According to Mr. Evans, extending the amortization period from prior cases to longer than one year could cause overlapping amortizations and push too many costs into the future.[343] Thus, SPS argues that the Commission should approve SPS's proposed one-year amortization. However, if the Commission decides to extend the amortization of the deferred pension and OPEB costs past one year, SPS requests that it be allowed to include the balance in rate base. SPS notes that Ms. Ramas agreed that rate base treatment would be appropriate if the Commission approves her amortization proposal.[344]

The ALJs recommend a two-year period, as proposed by Mr. Carver. There is no certainty when SPS will file another rate case. The ALJs find that a two-year amortization period appropriate given the evidence on that point. Further, because the ALJs are

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341 SPS Ex. 30, Schrubbe direct at 42.

342 OPUC Ex. 1, Ramas direct at 33-34; AXM Ex. 5, Carver direct at 23-24.

343 SPS Ex. 38, Evans rebuttal at 61.

344 OPUC Ex. 1, Ramas direct at 34-35.

recommending a two-year amortization for the deferred pension and OPEB costs, SPS should be allowed to include the associated regulatory asset in rate base.

D. Depreciation Expense

Depreciation is a system of accounting that distributes the cost of assets, less their net salvage value, over the assets' estimated useful life.[345] In rate-setting, depreciation is calculated to match expense (including retirement cost) with revenue over the life of a utility's assets, so that current and future customers who use the assets each pay their pro rata share for the investment.

Groups of utility assets are categorized by FERC account. When assets are retired, the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve. Each asset group's annual depreciation expense is computed by dividing original cost less allocated depreciation reserve and less the estimated net salvage value by the average remaining life. The resulting annual accrual amounts of all depreciable property within a function are totaled, and the total is divided by the original cost of all functional depreciable property to determine the depreciation rate.

Typically, individual assets within a group do not have identical lives or investment amounts. The group's average life is determined by comparing actual experience against survivor curves.[346] Based on review of historical data, current conditions, and future trends, a depreciation analyst selects an account's average service life and retirement dispersion pattern (dispersion curve) that identifies a pattern of retirements over a complete life cycle of an account. Like the witnesses, in this PFD the ALJs use [average service life] [dispersion curve] as a short reference to such a life-curve combination. For example, a combination of a service life of 70 years and an R4 dispersion curve is described as 70R4.[347]

345 An asset's net salvage value is its gross salvage value less the cost of removal, and may be positive or negative.

346 A survivor curve represents the percentage of property remaining in service at various age intervals.

347 These concepts are explained much more fully in SPS Ex. 13, Watson direct, Att. DAW-RR-2 at 6-15.

SPS's depreciation rates were last revised in 2009, based on a settlement (Docket No. 35763).[348] SPS's depreciation rates were unchanged in three subsequent cases based on settlements (Docket Nos. 38147, 40824, and 42004), and its previous depreciation rates were also set based on a settlement (Docket No. 32766).[349]

SPS's Application includes a Book Depreciation Accrual Rate Study at June 30, 2014 (Depreciation Study), which was conducted by Dane A. Watson with Alliance Consulting Group.[350] As described by Mr. Watson, the study included review of historical data and interviews with SPS personnel responsible for installation, operation, and removal of the assets. The study used two types of analysis: actuarial analysis (for accounts with a sufficient number of transaction years available to model), and Simulated Plant Record analysis (for mass distribution accounts without a vintage transaction history).[351]

Based on the Depreciation Study, SPS proposed depreciation rates that would increase depreciation expense by $25,973,159 (total company), as shown below:[352]

DEPRECIATION EXPENSE CHANGE (total company)	
Steam Production	$19,089,860
Other Production	$1,189,706
Transmission	$1,167,345
Distribution	$1,628,961
General	$2,897,287
Total Increase	**$25,973,159**

348 SPS Ex. 11, Perkett direct at 17, *citing Application of Southwestern Public Service Company for Authority to Change Rates, to Reconcile Fuel and Purchased Power Costs for 2006 and 2007, and to Provide a Credit for Fuel Cost Savings*, Docket No. 35763, Order (June 1, 2009).

349 Staff Ex. 4, Rich direct at 5.

350 SPS Ex. 13, Watson direct, Att. DAW-RR-2.

351 SPS Ex. 13, Watson direct at 16, 27, Att. DAW-RR-2.

352 SPS Ex. 11, Perkett direct at 21. Steam Production refers to assets used to generate electricity at SPS's gas- and coal-fired power plants; Other Production refers to assets at SPS's combustion turbine facilities. SPS Ex. 13, Watson direct at 16-17. SPS also proposed a change in amortization rates that would produce a net increase of $32,072 (total company). SPS Ex. 11, Perkett direct at 21.

As discussed below, TIEC and AXM contest SPS's proposed net salvage value for Production Plant, and in addition AXM contests SPS's proposed average service life or net salvage value for certain Transmission, Distribution, and General Plant accounts.[353] Regarding the disputed issues, the parties' proposals and the ALJs' recommendations are summarized below:

	SPS	AXM	ALJs
PRODUCTION & RELATED GENERAL PLANT			
Net salvage value	Negative 5% **(Staff agrees)**	Positive 5% **(TIEC agrees)**	Negative 2%
TRANSMISSION & RELATED GENERAL PLANT			
Land Rights (Account 350.2)			
Average service life	80R4	100R4	80R4
Transmission Substation Equipment (Account 353)			
Average service life	57R2.5	62R2	57R2.5
Net salvage value	Negative 20%	Negative 10%	Negative 20%
Transmission Poles & Fixtures (Account 355)			
Average service life	53R2.5	62R2	53R2.5
Net salvage value	Negative 60%	Negative 35%	Negative 35%
Order study	Opposes	Supports	Do not order study
Transmission Overhead Conductors & Devices (Account 356)			
Average service life	47R2	55S0.5	47R2
DISTRIBUTION & RELATED GENERAL PLANT			
Distribution Overhead Conductors & Devices (Account 365)			
Average service life	47R0.5	50R0.5	47R0.5
Distribution Line Transformers (Account 368)			
Average service life	45R1	48R0.5	45R1
Distribution Services (Account 369)			
Average service life	47R1.5	51R1	47R1.5

353 AXM witness Mr. Pous calculated that his recommendations would reduce SPS's total depreciation expense by $25.5 million. AXM Ex. 3, Pous direct at 4. SPS contests the accuracy of his calculations and asks that, if the Commission adopts any of Mr. Pous's proposals, SPS (through Mr. Watson's firm) be allowed an opportunity to calculate the impact on total depreciation expense. SPS Ex. 44, Watson rebuttal at 9-10.

GENERAL PLANT			
Miscellaneous Intangible Plant (Account 303)			
Routine Software			
Average service life	5 years	6 years	5 years
Large Software Systems			
Average service life	10 years	15 years	10 years
Order software study	Opposes	Proposes	Do not order study
Software fully amortized on or before Test Year end (June 30, 2014)	Include in rate base	Remove from rate base	Remove from rate base
Computer Equipment (Account 391.004)			
Average service life	5SQ	6SQ	5SQ
General Plant Structures & Improvements (Account 390)			
Net salvage value	Negative 10%	Positive 15%	Negative 10%
Transportation Equipment—Light Trucks/Heavy Trucks (Accounts 392.02/392.04)			
Average service life	10SQ/12SQ	12SQ/14SQ	12SQ/14SQ
Net salvage value	Positive 7%/6%	Positive 15%	Positive 7%/6%
Communication Equipment (Account 397)			
Average service life	15SQ	20SQ	15SQ

1. Production and Related General Plant

For these accounts, the only disputed issue involves SPS's proposed net salvage value for Production Plant, which TIEC and AXM vigorously oppose. SPS proposes that the existing net salvage value of positive 5% (which was set based on a settlement) be changed to negative 5%; Staff agrees with SPS; and TIEC and AXM recommend positive 5%. For reasons discussed below, the ALJs recommend negative 2%.

To support its proposed net salvage value for Production Plant, SPS presented a Production Dismantling Cost Study (Dismantling Cost Study), which was performed by Francis W. Seymore of TLG Services, Inc. (TLG).[354] The study estimated that dismantling SPS's 27 fossil-fuel generating units (fossil plants), located on 10 sites, would cost \$161.6 million in 2014. That equates to an overall net salvage value of negative 8%.[355] Despite that result, SPS proposes negative 5%, to comport with net salvage values for Production Plant

[354] SPS Ex. 12, Seymore direct, Att. FWS-RR-1.

[355] SPS Ex. 11, Perkett direct at 23.

the Commission has approved for other utilities.[356] SPS also presented evidence about the historical cost of dismantling SPS's and its affiliates' plants. TIEC and AXM challenge the reliability of the Dismantling Cost Study, SPS's assertions about the historical cost data, and SPS's and Staff's arguments about past Commission cases. Those issues are discussed below.

a. Dismantling Cost Study

SPS argues that the Dismantling Cost Study provides credible support for SPS's proposed net salvage value of negative 5%. TIEC and AXM disagree, arguing that:

- SPS witness Mr. Seymore and his consulting firm, TLG, lack the experience to properly estimate the cost to dismantle fossil plants, and TIEC witness Herbert Duane, Jr., is more qualified in that regard;
- The Dismantling Cost Study used a model that Mr. Seymore developed 30 years ago to estimate the cost of dismantling nuclear-fuel power plants (nuclear plants), not a fossil-plant fleet like that of SPS; and
- The Dismantling Cost Study made assumptions that inflate its cost estimates.

SPS objects that AXM and TIEC did not present an alternative study that could be used to estimate the dismantling cost for SPS's fleet. TIEC and AXM respond that SPS is trying to shift the burden of proof, and that SPS also did not propose using the negative 8% net salvage value indicated by the Dismantling Cost Study. For reasons discussed below, the ALJs conclude that the Dismantling Cost Study was not shown to be sufficiently reliable to prove that the net salvage value is negative 8%, as the study indicated, or even negative 5%, as SPS is proposing in this case.

356 SPS Ex. 13, Watson direct at 14.

i. Credentials to Estimate Fossil Plant Dismantling Costs

Mr. Seymore agreed that most of his experience involves dismantling nuclear plants rather than fossil plants and that he has never been on site or prepared specifications for dismantling a fossil plant.[357] He testified that, when preparing dismantling cost studies, there are many similarities between nuclear plants and fossil plants, but he acknowledged that there are major differences and many more opportunities for problems to arise in dismantling nuclear plants compared to fossil plants.[358] In discovery, SPS identified four fossil plants for which TLG had prepared dismantling bid specifications, assisted in selecting the demolition contractor, or prepared a bid for complete dismantling of the plant, with the most recent such work occurring in the 1990s.[359] Mr. Seymore testified that TLG relies on field experience from nuclear decommissioning to prepare fossil plant studies.[360]

TIEC witness Mr. Duane has developed demolition cost estimates for numerous fossil plants and has been the demolition contractor for actual fossil plant demolition. He has been involved in hundreds of demolition projects over the last 40 years, including two fossil plants within the last 10 years.[361]

The ALJs conclude that the evidence, including Mr. Seymore's credentials,[362] supports TIEC's contention that Mr. Seymore and TLG have far more experience relating to dismantling nuclear plants than fossil plants.

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[357] Tr. at 221.

[358] SPS Ex. 12, Seymore direct at 9-11.

[359] TIEC Ex. 5, Duane direct, Exh. HD-2 at 64-65, 68 (SPS RFI responses).

[360] SPS Ex. 12, Seymore direct at 9-10.

[361] TIEC Ex. 5, Duane direct at 5; SPS Ex. 46, Davidson rebuttal, Exh. AJD-RR-R3 at 1 (TIEC RFI response).

[362] *See* SPS Ex. 12, Seymore direct at 4-9.

ii. Use of a Model Developed 30 Years Ago for Nuclear Plants

The Dismantling Cost Study used the DECCER cost model, which is based on a document entitled "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates" (Nuclear Decommissioning Guidelines), which Mr. Seymore developed more than 30 years ago for use in demolishing nuclear plants.[363] Mr. Duane stated that:

> the DECCER cost model, which was designed and implemented by Mr. Seymore, is not based on experience in the actual bidding and demolition of fossil fuel plants. Instead, it is based on untested, unsupported and undocumented theoretical assumptions related to nuclear plants. Whatever the value of using a theoretical approach might be in connection with nuclear plants, a theoretical approach is not appropriate for fossil fuel plants, because there is real world information available based on hundreds of actual demolitions.[364]

The Dismantling Cost Study described its methodology, assumptions, and SPS generation-station-specific adjustments. Mr. Seymore testified that the DECCER model has been adapted for use with fossil plants and that, for the Dismantling Cost Study, the inputs to the model were SPS-based and appropriate for use in the context of dismantling fossil plants.[365]

The ALJs find that Mr. Seymore provided only conclusory evidence that the DECCER model itself has been adapted to be suitable for fossil plants. Concerns about some of the Dismantling Cost Study's specific assumptions and inputs are discussed below. After considering all of the evidence relating to the study, the ALJs find that the above concern expressed by Mr. Duane has sufficient validity to warrant discounting the reliability of the Dismantling Cost Study's cost estimates.

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[363] SPS Ex. 12, Seymore direct at 4; Tr. at 222-223.

[364] TIEC Ex. 5, Duane direct at 13.

[365] SPS Ex. 12, Seymore direct at 20, Att. FWS-RR-1 at 22-23, 22-29; Tr. at 221, 223.

iii. Assumed Demolition Method

The Demolition Cost Study assumed that a controlled engineered demolition method will be used to demolish SPS's power plants.[366] Mr. Duane stated that, under that method, the plant's components are disassembled and removed by laborers before the structure is taken down. He testified that the method is not commonly used to demolish fossil plants and significantly inflates the study's estimated costs.[367] He expected SPS's plants to be demolished using a total demolition method, which he described as follows:

> (1) the asbestos would be remediated; (2) certain building materials and equipment that have resale value and could be damaged during demolition would be removed and stored in a safe area; (3) the remainder of the plant would be taken down through the use of heavy demolition equipment (*e.g.*, shears, excavators, wrecking balls) and/or explosives; and (4) finally the scrap would be picked out of the debris of the plant lying on the ground.[368]

Mr. Seymore stated that worker safety considerations support use of the controlled engineered demolition method.[369] Mr. Duane responded that workers are better protected under the total demolition method, because they work inside safety-approved cabs during the mechanical and explosion phase of demolition, rather than inside the building. He also criticized the Dismantling Cost Study's reliance on what he described as "extremely out of date" studies and publications, such as a 1989 methodology to estimate fossil plant dismantling costs.[370] He explained:

> [T]oday there are more advanced demolition technologies that allow plants to be taken down in less time and for less money. These include (1) advances in shears, grapples, skid loaders and excavators; (2) the introduction of new robotic equipment; and (3) advances in explosive technology, including shaped charges,

[366] Tr. at 223; SPS Ex. 12, Seymore direct at 14.

[367] Tr. at 223-224; TIEC Ex. 5, Duane direct at 8-9.

[368] TIEC Ex. 5, Duane direct at 8-9.

[369] SPS Ex. 12, Seymore direct at 14.

[370] TIEC Ex. 5, Duane direct at 11-12.

explosive detonating cord, and new timing equipment for the sequencing of explosives.[371]

Mr. Seymore testified that the controlled engineered demolition methodology was used for all of SPS's and its affiliates' fossil plants that have been dismantled in the past 10 years.[372] SPS witness Alan J. Davidson stated that in the past, SPS and its affiliates have used a controlled engineered demolition method, which he said SPS and TLG define as not precluding the use of heavy mechanical equipment.[373] He commented: "My experience has been that the contractors involved in demolitions to date for SPS and other Xcel Energy plants prefer the controlled demolition method to maximize salvage of the scrap from the process."[374]

TIEC argues that SPS's Tucumcari and Celanese plants were demolished using heavy equipment, including shears,[375] and within the last 10 years at least one power plant owned by SPS or an affiliate was demolished using a wrecking ball.[376] Mr. Davidson testified that those plants were not representative of SPS's fleet. The Celanese plant was a cogeneration unit that lacked typical power plant components (such as boilers, condenser, feed water heaters, and cooling towers) and the Tucumcari plant was an approximately 18-MW, nine-unit site with very old diesel generators.[377] The ALJs agree that those plants are not representative of SPS's fossil fleet.

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371 TIEC Ex. 5, Duane direct at 12.

372 SPS Ex. 43, Seymore rebuttal at 12-13.

373 SPS Ex. 46, Davidson rebuttal at 11.

374 SPS Ex. 46, Davidson rebuttal at 13. Mr. Duane disagreed, stating that a contractor would use the controlled engineered demolition method only if it was trying to extract plant equipment for resale. TIEC Ex. 5, Duane direct at 9, 15.

375 TIEC Ex. 41 at 1686, 1805; Tr. at 230-231; TIEC Ex. 5, Duane direct, Exh. HD-3 at 73, 83.

376 Tr. at 631-632; TIEC Ex. 52 (SPS RFI response).

377 SPS Ex. 46, Davidson rebuttal at 7-8.

Mr. Seymore acknowledged that his study does not assume the use of explosive techniques, wrecking balls, or shears.[378] He testified:

> Q: Have you changed your study in light of the fact that SPS has used shears to demolish power plants?
>
> A We're currently in the process of trying to acquire the data to bring it into the models for shears. We have revised other unit cost factors for using hydraulic demolition hammer, but not finding as much public data available on the shears, so that's in process. But, no, it is not in this estimate.
>
> Q Okay. So when you filed this estimate, you didn't ask SPS how they had been demolishing their power plants?
>
> A. No.[379]

Mr. Seymore's testimony quoted above raises concern as to how critically SPS and TLG investigated the suitability of the study's model, assumptions, and data to estimate the cost of dismantling SPS's fossil plants. Regarding this specific issue, however, SPS demonstrated that over the last 10 years, SPS and its affiliates have used the controlled engineered method to demolish their plants, with exceptions limited to plants not representative of SPS's fossil fleet. Given that evidence, the ALJs find unconvincing Mr. Duane's opinion that the controlled engineered demolition method is not commonly used for fossil plants. The ALJs find that the assumption in the Dismantling Cost Study that the controlled engineered method will be used to demolish SPS's fossil fleet is reasonable.

iv. Assumption that No Plant Equipment Will Be Reused or Resold

The Dismantling Cost Study included a credit for the scrap value of materials generated in dismantling but assumed that no equipment in SPS's plants will be reused or resold except for

[378] Tr. at 224-226; *see also* TIEC Ex. 37 (SPS RFI response); SPS Ex. 43, Seymore rebuttal at 7-8.

[379] Tr. at 233-234.

scrap.[380] Mr. Seymore explained that the plants will be at the end of their useful life, but acknowledged that SPS sometimes replaces equipment during a plant's life. He did not estimate the value of equipment that will be in SPS's plants when they are shut down.[381]

Mr. Duane testified that "there is an active market for used plant equipment including turbines, precipitators, boilers, valves, conveyers, conveyor belts, electrical equipment, pumps, tanks, lighting, and steel grating."[382] Citing his "personal experience selling millions of dollars worth of such used equipment," Mr. Duane stated that "(s)ales of these items from SPS plants could provide tens of millions of dollars in value."[383] As discussed later, in the PFD section regarding SPS's historical dismantling costs, SPS witness Mr. Davidson testified that SPS has tried to reuse or resell equipment, and has done so in some instances, but that those instances are atypical and SPS does not expect to realize much value from those efforts when dismantling its current fossil fleet. The ALJs found Mr. Davidson to be a credible witness on those points. The ALJs found Mr. Duane's statement that SPS could realize tens of millions of dollars from reusing or reselling plant equipment to be conclusory and speculative.

The ALJs agree with Mr. Duane, however, that Mr. Seymore should have contacted well-known dealers or asset recovery firms to determine the market for SPS's equipment or otherwise more actively investigated that issue.[384] The ALJs find that the Dismantling Cost Study's assumption that the plant equipment has a value of zero results in overstated cost estimates.

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380 SPS Ex. 12, Seymore direct at 14; Tr. at 238.

381 Tr. at 238-239, 241.

382 TIEC Ex. 5, Duane direct at 19. Mr. Pous testified similarly. AXM Ex. 3, Pous direct at 14.

383 TIEC Ex. 5, Duane direct at 19.

384 TIEC Ex. 5, Duane direct at 19.

v. Assumption that No Structures or Sites Will Be Reused

The Dismantling Cost Study assumed that no structures, foundations, parking lots, or roads at SPS's plant sites will be reused or allowed to stay in place and that instead each site will be returned to its natural condition, including removing all structures to three feet below grade.[385] Mr. Seymore acknowledged that roads and parking lots might be allowed to stay in place and that "any structure that's capable of holding itself up could probably be reused."[386] TIEC notes that, although parts of SPS's Riverside plant were demolished many years ago, the site has been reused for a new combined cycle installation.[387] In 2010, Mr. Seymore estimated the cost of demolishing that plant at over $29 million, but the actual demolition cost was $8.5 million.[388] SPS witness Mr. Davidson considered the Riverside plant situation to be atypical and said that additional demolition work will need to be performed there. He acknowledged, however, that SPS does not currently plan to demolish the remaining facilities.[389]

Mr. Seymore testified: "At the end of dismantling activities, the plant site will be in a condition such that the land will be available for an alternative use."[390] AXM witness Mr. Pous argued that if ratepayers are asked to pay for complete remediation of land so the sites can be sold for a different use, those costs should be offset by the value created.[391] SPS witness Lisa H. Perkett testified that depreciation rates are set to recover removal costs for equipment and buildings and, because land is not depreciated, it was properly excluded from the depreciation analysis.[392] Mr. Duane opined that savings from selling land after a plant has been demolished could possibly far exceed the cost of the demolition.[393] Ms. Perkett responded that

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385 Tr. at 239-240; SPS Ex. 12, Seymore direct, Att. FWS-RR-1 at 13.

386 Tr. at 239-240.

387 SPS Ex. 46, Davidson rebuttal at 9-10.

388 TIEC Ex. 5, Duane direct, Exh. HD-2 at 52-53 (SPS RFI response).

389 SPS Ex. 46, Davidson rebuttal at 8-10.

390 SPS Ex. 12, Seymore direct at 15.

391 AXM Ex. 3, Pous direct at 12, 17.

392 SPS Ex. 42, Perkett rebuttal at 12.

393 TIEC Ex. 5, Duane direct at 21.

including land in the analysis would be "extremely unlikely" to change the results, because the study's cost estimate contemplates restoring the land only to industrial use and SPS's plants are located on land with limited, if any resale value.[394] Mr. Seymore explained that the SPS plant sites are not close to any major metropolitan area, tourist attraction, or navigable waterway.[395]

SPS did not prove that the Dismantling Cost Study's assumptions that (1) all plant sites will be remediated to the land's natural state, (2) no structures, foundations, parking lots, or roads will be reused or allowed to stay in place, and (3) no value should be assigned to the remediated land, are reasonable. The ALJs find that those assumptions inflate the study's cost estimates. The ALJs find credible, however, SPS's testimony indicating that the land values would be typical for sites in the region that are suitable for industrial use and not near major metropolitan areas or navigable waterways.

vi. Overtime Assumption

Mr. Seymore assumed that the demolition work would be performed on a 50-hour work week, necessitating overtime pay.[396] Mr. Duane considered that assumption to be "extremely unusual and costly."[397] The last actual demolition bidding instructions TLG created, for LCRA's Comal power plant, stated: "Owner expects the Contract to be performed during normal 40-hour work weeks. If Contractor wishes to work overtime or multiple shifts, Contractor and Owner shall confer and agree on the scheduling to coordinate with Owner's other activities . . . ."[398] Mr. Seymore opined that some SPS plants are "in the middle of nowhere" and that laborers will not work there without a guaranteed 50-hour work week.[399] Finding Mr. Seymore's unsupported opinion on that point to be unconvincing, the ALJs conclude that SPS did not prove the

[394] SPS Ex. 42, Perkett rebuttal at 12.

[395] SPS Ex. 43, Seymore rebuttal at 21.

[396] SPS Ex. 12, Seymore direct, Att. FWS-RR-1 at 26; Tr. at 235.

[397] TIEC Ex. 5, Duane direct at 16.

[398] TIEC Ex. 42 at 19.

[399] Tr. at 246.

reasonableness of the Dismantling Cost Study's assumption that all dismantling at SPS's plants will be performed on a 50-hour work week. The ALJs find that in consequence, the study's dismantling cost estimates are inflated.

vii. Contingency Assumption

Mr. Seymore testified that, while at TLG in 1986, he was a major contributor to the Nuclear Decommissioning Guidelines.[400] Regarding the contingency assumed in the Dismantling Cost Study, he explained:

> Consistent with the guidance provided by both R. S. Means and the Guidelines, a 15% contingency value was applied to all cost elements, with the exception of asbestos remediation. Since the regulatory requirements imposed on asbestos remediation efforts are similar to those working in a radioactively contaminated environment, and the Guidelines suggest a 25% contingency for the removal of radioactively contaminated systems, a 25% contingency was applied to asbestos removal activities.[401]

Mr. Duane opined that nuclear plant decommissioning in the 1980s, when the Nuclear Decommissioning Guidelines were developed, presented more uncertainties than does asbestos removal in fossil plants now. In his experience, an appropriate general contingency is 6% to 7%, and 12% for asbestos removal.[402] Mr. Pous noted that in recent years, the Commission has capped the contingency for nuclear plant decommissioning at 10%.[403] Mr. Seymore responded that TLG believes the Commission's 10% contingency for nuclear plants is not based upon any analysis of the uncertainties involved and is insufficient to recover costs. He also cited the Commission's approval of a 15% contingency in Docket No. 40443, involving fossil plants owned by SWEPCO.[404]

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[400] SPS Ex. 12, Seymore direct at 8.

[401] SPS Ex. 12, Seymore direct at 23.

[402] TIEC Ex. 5, Duane direct at 22-23.

[403] AXM Ex. 3, Pous Direct at 13.

[404] SPS Ex. 43, Seymore rebuttal at 24; Docket No. 40443, Order on Rehearing, FF 193; Docket No. 40443, PFD at 185.

The evidence presented in Docket No. 40443 is not before the ALJs. The ALJs find Mr. Seymore's reasons for using the Dismantling Cost Study's contingencies to be unpersuasive. As he acknowledged, "(t)here are many more opportunities for problems to arise in nuclear plant decommissioning than in fossil plants" and "(t)here are fewer potential hazards for the worker and . . . the potential for problems is lower."[405] Mr. Duane's testimony on this issue was more credible than that of Mr. Seymore. The ALJs conclude that the Dismantling Cost Study used contingencies that inflated its estimates of the cost of dismantling SPS's fossil plants.

viii. Accuracy of TLG's Past Cost Estimates

Regarding power plants owned by SPS or its affiliates, Mr. Duane noted that, in his 2010 study, Mr. Seymore estimated a total cost to dismantle the Celanese, Riverview, Tucumcari, and Riverside plants at $36,596,644, but the actual total cost was $10,016,612.[406] Mr. Davidson responded that those plants are atypical. The Celanese plant was a cogeneration unit and because the chemical site was shut down, the chemical plant owner paid SPS an early termination penalty. The Tucumcari plant was an approximately 18 MW, nine-unit site. For the Riverview plant, more limited abatement was required than expected; dismantlement savings were realized when SPS re-used the combustion turbine in its Quay County plant; and only part of the plant was dismantled because the existing site was used for a new combined cycle installation. In Mr. Davidson's opinion, with the possible exceptions of Carlsbad and Quay County, the SPS plants included in the Dismantling Cost Study are more akin to the Cherokee 1 and 2 and Cameo plants, for which TLG's estimates from prior studies have been close to the actual dismantling costs.[407] TIEC responds that Mr. Seymore's 2011 estimate to dismantle the Cameo plant, which was performed one year after retirement, overstated the actual costs by less than $700,000, but his 2007 estimate exceeded the actual costs by nearly $19 million.[408]

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405 SPS Ex. 12, Seymore direct at 11; SPS Ex. 43, Seymore rebuttal at 11, 24.

406 TIEC Ex. 5, Duane direct, Exh. HD-2 at 52-53.

407 SPS Ex. 46, Davidson rebuttal at 7-10.

408 TIEC Ex. 5, Duane direct, Exh. HD-2 at 52-53; TIEC Ex. 56 at 7 (SPS RFI response).

The ALJs conclude that, regarding now-dismantled plants of SPS and its affiliates, TLG's dismantling cost estimates have tended to exceed the actual costs, in some instances by a small amount but in other instances by a large amount.

Mr. Seymore testified that his study was not meant as a dismantling plan but as a reasonable estimate of costs that will be incurred at final shutdown of the plants, in order to establish a funding basis long before those costs are incurred.[409] The ALJs agree, but the suitability of the Dismantling Cost Study's model and assumptions for SPS's fossil plants is directly related to the reasonableness of its cost estimates. The evidence shows that, for several reasons, the Dismantling Cost Study produced inflated cost estimates. Considering all of the evidence, the ALJs find that the Dismantling Cost Study was not proven to be sufficiently reliable to prove that SPS's net salvage value is negative 8%, as the Dismantling Cost Study estimated, or negative 5%, as SPS proposes.

b. Historical Dismantling Costs

Mr. Davidson testified that: (1) his duties included reviewing dismantling bids and contracts and monitoring the project managers responsible for dismantling SPS's retired generation units; (2) he was generally familiar with Xcel Energy's generation units and dismantling projects; and (3) he was knowledgeable about the estimated and actual costs of dismantling retired SPS and Xcel Energy generation units.[410] He discussed the following table showing the actual prices of selected dismantling bids for those plants:[411]

Utility	Generating Unit	Year Retired	Actual Price of Selected Dismantling Bid
SPS	Celanese	2012	$47,724**
SPS	Riverview	2012	$1,131,839
SPS	Tucumcari	2011	$297,129
NSPM	Riverside	2009	$8,539,920

409 SPS Ex. 12, Seymore direct, Att. FWS-RR-1 at 9; SPS Ex. 43, Seymore rebuttal at 8-9.

410 SPS Ex. 46, Davidson rebuttal at 6.

411 TIEC Ex. 5, Duane direct, Exh. HD-2 at 52-53 (SPS RFI response).

Utility	Generating Unit	Year Retired	Actual Price of Selected Dismantling Bid
NSPM	Minnesota Valley	2013	$3,511,454*
PSCo	Cherokee 1	2014	$8,365,422
PSCo	Cherokee 2	2014	$9,901,695
PSCo	Cameo	2010	$16,822,433

* Only abatement has been worked on to date

** Includes a credit of $449,813 for early retirement of chemical plant

He testified that of the plants listed above, Cherokee 1 and 2 and Cameo are medium-sized, traditional fossil plants that are the most representative of SPS's fossil fleet (except for SPS's Carlsbad and Quay County units). Noting that the table demonstrates that all instances of dismantling SPS and Xcel Energy generation units involved significant dismantling costs, he concluded that SPS should expect to expend significant funds in dismantling its retired generation plants.[412]

Mr. Davidson testified that in his experience, the sale of scrap is generally handled by applying an agreed-upon, scrap-credit dollar amount that is incorporated into the contract price for dismantling the plant. Historically, the scrap credits SPS and Xcel Energy have been able to obtain have been small compared to the overall dismantling costs. For example, the initial bid price for the successful contractor for dismantling Cherokee Units 1 and 2 was $11,133,934, which included a $1,520,529 scrap credit. Mr. Davidson was not aware of any demolition contractors paying for the demolition rights for SPS and Xcel Energy plants.[413]

Mr. Davidson said that examples in which SPS or its affiliates have found equipment that could be resold or reused at other plants are atypical. Those examples include: (1) moving a combustion turbine from the Riverview plant to the Quay County plant; (2) retrofitting and reusing a steam turbine from NSPM's original Riverside facility; (3) moving a "very small unit" used for black starts from the Tucumcari plant to the Quay County plant; and (4) selling a gas

[412] SPS Ex. 46, Davidson rebuttal at 7-12.

[413] SPS Ex. 46, Davidson rebuttal at 13-14.

turbine from the Phillips 66 cogeneration facility.[414] He commented: "We have an investment recovery group that does spend time after a plant is retired if it's been there a long time. They do try to market the equipment. So we have put it up there for sale. We've just had very little success in anybody buying it."[415] According to Mr. Davidson, in the few instances in which SPS has sold equipment, or otherwise realized equipment salvage value, from its retired power plants, the total dollar amount of salvage value that has been realized, compared to the plant amount retired, has been insignificant.[416] He explained:

> Given the technological changes that have occurred in the electric generation industry, such as the growth of renewable energy and development of more efficient natural gas combined cycle power plants, coupled with increasing environmental regulations, there is simply not a viable resale market for parts from 50+ year old fossil fuel power plants.[417]

Mr. Davidson also testified that over the past 30 years, SPS has had no success in selling any of its previously retired units. Although SPS repurposed a limited amount of generation equipment from the retired Tucumcari and Riverview sites, he did not believe that any of the remaining SPS units in service now could be repurposed. SPS has no plans to repurpose any of its units. All of SPS's plants retired since 1984 have been demolished and the site leveled, except one plant that was retired in September 2013 and is scheduled for demolition in 2019.[418]

Mr. Davidson concluded that the historical cost information indicates that SPS cannot reasonably expect to make money in dismantling its plants, as a positive net salvage value implies.[419] The ALJs agree. Mr. Davidson was a credible witness on that point. In contrast, the

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414 SPS Ex. 46, Davidson rebuttal at 7-10, 14-18, Att. AJD-RR-R1, Att. AJD-RR-R2 at 1 (TIEC RFI response); Tr. at 629-630, 634-635.

415 Tr. at 634.

416 SPS Ex. 46, Davidson rebuttal at 15-18, Att. AJD-RR-R2.

417 SPS Ex. 46, Davidson rebuttal at 15.

418 SPS Ex. 46, Davidson rebuttal at 17-18.

419 SPS Ex. 46, Davidson rebuttal at 5, 12, 19.

ALJs found no reliable, applicable evidence indicating that the net salvage value for SPS's Production Plant will be positive.

For example, Mr. Pous discussed Texas utilities whose plants were not dismantled but instead were sold, resulting in positive net salvage. He acknowledged, however, that most such plants were sold to comply with deregulation requirements[420] that do not apply to SPS. Because many of the plants were probably not at the end of their useful lives, the ALJs find they were more likely to have positive net salvage value than SPS's plants will have when they are retired. TIEC cites the example of the Celanese plant, for which the demolition contractor paid SPS $19,280 for the demolition rights.[421] As Mr. Davidson discussed, however, that plant was a cogeneration unit that was retired before its useful life ended, and SPS incurred other costs to dismantle its portion of that plant.[422] Regarding other companies, Mr. Duane identified some examples of demolition contractors paying for the right to demolish power plants.[423] SPS responds that such examples are anecdotal and there is no basis to regard them as similar to SPS's fleet. Based on the evidence, the ALJs agree.

c. Past Commission Decisions

Mr. Watson testified that in Docket No. 40443, involving SWEPCO, the Commission approved net salvage values for production assets ranging between 0% and negative 22%.[424] The ALJs note that in that case, the Commission set a net salvage value based on a plant-specific

[420] AXM Ex. 3, Pous direct at 16-17.

[421] TIEC Ex. 49 at 1,998, 2,105; Tr. at 642-643.

[422] Tr. at 649; SPS Ex. 46, Davidson rebuttal at 8, 19; TIEC Ex. 5, Duane direct, Exh. HD-2 at 52-53.

[423] TIEC Ex. 5, Duane direct at 20-21.

[424] SPS Ex. 13, Watson direct at 20, n. 9 (*citing* Docket No. 40443, Order on Rehearing, FFs 193-194, and Docket No. 40443, Direct Testimony of David A. Davis, Exh. DAD-1 at 16-17).