398. The Department recommended that, due to various Department adjustments to the test year, the CWC associated with the Lead/Lag Study be adjusted or updated to reflect the adjustments made to MERC's initial request.[561]

399. MERC agreed that the Lead/Lag Study should be updated based upon final adjustments made in this docket from MERC's initial filing and accepted that the CWC result of such changes should be incorporated into final rates.[562]

400. No other party offered testimony regarding this issue.

401. The Administrative Law Judge finds that the proposed adjustment to MERC's Lead/Lag Study and resultant CWC adjustment is reasonable.

H. Gas Storage Balance Adjustment

402. MERC proposed to recover $9,211,957 of gas storage inventory in the test year.[563] MERC calculated this amount based on NYMEX data from May 15, 2015 and is equivalent to the 13-month average of the amounts for the period December 2015 to December 2016.[564]

403. The Department recommended that MERC's test year gas storage inventory be decreased by $1,153,983 to reflect the updated actual gas storage inventory as of December 31, 2015.[565]

404. MERC agreed that an update was warranted, but proposed an update based on updated NYMEX prices at the time, along with the corrections made to MERC's initial proposal and compliance filing in Docket No. G011/MR-15-748.[566] MERC provided an update to the base cost of gas in this proceeding and in Docket No. G011/MR-15-748,[567] and the updated cost of gas resulted in a reduction in the 13-month average balances for gas storage of $2,725,136.[568]

405. The Department agreed with the adjustment to gas storage inventory of $2,725,136.[569]

406. No other party offered any testimony regarding the gas storage balance.

[561] Ex. 416 at 24-25, MAS-8 (St. Pierre Direct)
[562] Ex. 45 at 38 (DeMerritt Rebuttal).
[563] Ex. 4, Vol. 3, Doc. 2 at 5 (Application).
[564] Ex. 407 at 3 (La Plante Direct).
[565] Ex. 407 at 3 (La Plante Direct).
[566] Ex. 45 at 13 (DeMerritt Rebuttal).
[567] *See* Compliance Filing – Base Cost of Gas Update (Apr. 12, 2016) (eDocket No. 20164-119985-02).
[568] Ex. 45 at 13 (DeMerritt Rebuttal).
[569] Ex. 408 at 2-3 (La Plante Surrebuttal).

407. Based on the agreement of the parties to reduce MERC's proposed gas storage balance of $9,211,957 by $2,725,136, the Administrative Law Judge finds MERC's gas storage balance should be $6,486,821 for the 2016 test year.

I. Interest Synchronization

408. Interest synchronization is used in ratemaking to determine the amount of interest expense to be used in the calculation of income tax.[570]

409. The Department recommended that MERC's test year interest synchronization be adjusted to incorporate various adjustments to the test year.[571]

410. MERC agreed the interest synchronization calculation should be updated.[572]

411. MERC and the Department are in agreement that the actual level of the interest synchronization adjustment is dependent on the final outcome of rate base and interest adjustments.[573]

412. No other party offered testimony regarding interest synchronization.

413. The Administrative Law Judge finds that MERC's interest synchronization should be adjusted and MERC should recalculate the adjustment as part of its final compliance filing to reflect final rate outcomes in this proceeding.

J. Non-Fuel O&M Expense Inflation

414. This proceeding is based on a test year of 2016 for MERC's operations. To determine its test year non-fuel O&M expense, MERC used its actual 2014 non-fuel O&M costs, and applied inflation factors for 2015 and 2016 to arrive at base O&M levels.[574] MERC then adjusted this 2016 O&M expense value for certain known and measurable changes (K&M adjustments) to arrive at its test year projected 2016 non-fuel O&M expenses.[575]

415. MERC inflated non-labor expenses by 0.864 percent in 2015 and 2.413 percent in 2016, and labor expenses by 2.60 percent in 2015 and 2.85 percent in 2016.[576]

416. The Department expressed concern with the inflation rates used for non-labor expenses and recommended that MERC use the non-labor inflation rates of 0.633 percent for 2015 and 1.680 percent for 2016 because these rates reflect more current non-labor inflation rates (October to December 2015) than those used by MERC in its

[570] Ex. 416 at 44 (St. Pierre Direct).
[571] Ex. 416 at 45, MAS-7 (St. Pierre Direct).
[572] Ex. 45 at 37 (DeMerritt Rebuttal).
[573] Ex. 45 at 37 (DeMerritt Rebuttal); Ex. 416 at 45 (St. Pierre Direct).
[574] Ex. 41 at 24 (DeMerritt Direct).
[575] Ex. 41 at 24 (DeMerritt Direct).
[576] Ex. 41 at 25 (DeMerritt Direct).

initial filing (October 2014 to February 2015).[577] The Department's adjustment for non-labor inflation reduced the test year non-fuel O&M expense by $245,850.[578]

417. The OAG discussed two concerns with respect to MERC's inflation factors. The OAG's first concern related to the use of outdated and inaccurate inflation estimates.[579] The OAG's second concern was that MERC misapplied the inflation estimates from the Energy Information Administration (EIA) source document when calculating its inflation factor.[580] The OAG recommended that MERC's non-labor inflation rate be adjusted to reflect the current data, and that MERC fix identified mistakes.[581]

418. MERC agreed with the OAG's recommendation to use the most recent inflation forecast, and that use of the EIA Consumer Price Index was incorrect.[582] MERC updated its 2015 and 2016 non-labor inflation rates accordingly, which resulted in non-labor inflation rates of 0.307 percent for 2015 and 1.104 perfect for 2016.[583] The updated inflation factors resulted in a reduction in MERC's non-fuel O&M forecast of $475,295.[584]

419. The Department also agreed with the OAG's recommendation. Both the Department and the OAG agreed with MERC's subsequent update of the non-labor inflation rates.[585]

420. No other party offered testimony on this issue.

421. The Administrative Law Judge finds the use of the updated inflation rates in determining the non-fuel O&M forecast is appropriate and reasonable.

K. Charitable Contributions

422. MERC included $34,868 of charitable contributions in the 2016 revenue requirements.[586]

423. The Department recommended a reduction in test year administrative and general expense of $17,599 based on application of the Commission's policy on charitable contributions, which provides that only 50 percent of qualified contributions are allowed as test year operating expenses.[587]

[577] Ex. 416 at 43 (St. Pierre Direct).
[578] Ex. 416 at 32 (St. Pierre Direct).
[579] Ex. 300 at 33 (Lebens Direct).
[580] Ex. 300 at 34 (Lebens Direct).
[581] Ex. 300 at 35 (Lebens Direct).
[582] Ex. 45 at 21 (DeMerritt Rebuttal).
[583] Ex. 45, SSD-R4 (DeMerritt Rebuttal).
[584] Ex. 45 at 21 (DeMerritt Rebuttal).
[585] Ex. 417 at 21 (St. Pierre Surrebuttal); Tr. Vol 1 at 169 (Lebens).
[586] Ex. 41 at 39 (DeMerritt Direct); Ex. 4, Vol. 3, Doc. 15 (Application).
[587] Ex. 407 at 11-12 (La Plante Direct).

424. MERC agreed with the Department's adjustment to reduce expenses by $17,599 for charitable contributions.[588]

425. No other party offered any testimony regarding charitable contributions.

426. The Administrative Law Judge finds MERC's charitable contributions should be reduced by $17,599 for the 2016 test year.

L. Conservation Improvement Program (CIP) Matters

427. MERC has an approved CIP on file with the Department.[589]

428. The Legislature requires utilities to make certain CIP expenditures pursuant to Minn. Stat. § 216B.241 (2016), and has established a requirement for cost recovery of the expenditures in utility rates.

429. Specifically, Minn. Stat. § 216B.16, subd. 6b, allows utilities to recover costs of relevant conservation improvements:

> Except as otherwise provided in this subdivision, all investments and expenses of a public utility . . . incurred in connection with energy conservation improvements shall be recognized and included by the commission in the determination of just and reasonable rates as if the investments were directly made or incurred by the utility in furnishing utility service.

430. MERC received Commission approval to implement a Conservation Cost Recovery Adjustment factor in order to recover the amount by which actual CIP expenditures are different from the amount recovered through the Conservation Cost Recovery Charge (CCRC) factor, which is embedded in distribution rates, plus the amount of any Commission-approved CIP financial incentive, on an annual basis.[590]

431. MERC's most recent annual filing was approved by the Commission at $0.00865 per therm, effective January 1, 2016.[591]

432. MERC's request to update its CCRC factor was approved in its last rate case with CCRC set to $0.02448 per therm.[592]

433. The Commission ordered that in future rate cases, MERC shall change the CCRC rates at the beginning of the interim rates period and again when implementing final rates.[593]

[588] Ex. 45 at 29 (DeMerritt Rebuttal).
[589] Ex. 41 at 56 (DeMerritt Direct).
[590] Ex. 41 at 57 (DeMerritt Direct).
[591] Ex. 41 at 57 (DeMerritt Direct).
[592] 2013 MERC RATE CASE ORDER at 57.
[593] 2013 MERC RATE CASE ORDER at 63.

434. Effective January 1, 2016, with interim rates, MERC implemented a CCRC of $0.02767 per therm.[594]

435. On August 1, 2014, the Deputy Commissioner of the Department issued an Order to change utility triennial filing schedules by extending utilities with 2013-2015 triennial CIP plans by one year, through calendar year 2016.[595] The Deputy Commissioner approved a spending budget of $11,280,537 for MERC on October 12, 2015.[596]

436. As part of this proceeding, MERC proposed to update its CCRC factor included in base rates to recover the 2016 CIP program expenses of $11,280,537,[597] and included an amount of $11,278,885 in the test year income statement.[598]

437. The Department asserted that the test year amount should be increased to the Deputy Commissioner's approved amount of $11,280,537 and recommended that MERC increase Amortization Expense in the test year by $1,652 for CIP expense.[599] The Department also recommended that the Commission require MERC to: (1) update its CIP tracker carrying charge based on the approved short term cost of debt; (2) make a true-up adjustment to the CIP tracker at the time of final rates and report the calculation in the final rates compliance filing; and (3) report in the Company's final rate compliance filing, the calculation of the CCRC rate based on the Commission's order regarding the level of CIP expenses divided by the approved level of sales and provide the calculation of any true-up adjustments to the CIP tracker.[600]

438. No other party offered any testimony regarding the CIP issue.

439. MERC agreed with the Department's recommendation to adjust the Amortization Expense by $1,652 to include the correct amount in the test year for CIP expense.[601] MERC did not comment on the Department's other CIP-related recommendations.[602]

440. The Administrative Law Judge finds that the Department's recommendations are reasonable. The Administrative Law Judge concludes the Amortization Expense in the test year should be increased by $1,652 for the CIP expense.

[594] Ex. 2, Vol. 1 at 6 (Application); ORDER SETTING INTERIM RATES (Nov. 30, 2015) (eDocket No. 201511-116010-01); Compliance Filing -- Interim Rate Tariffs (Dec. 10, 2015) (eDocket No. 201512-116372-01).
[595] *In the Matter of Extending the 2013-2015 CIP Triennial Plans Through 2016*, MPUC Docket No. G007, G011/CIP-12-548, ORDER (Aug. 1, 2014).
[596] *Minn. Energy Res. 2016 Nat. Gas Conservation Improvement Program Plan Extension*, MPUC Docket No. G007, G011/CIP-12-548, DECISION (Oct. 12, 2015).
[597] Ex. 41 at 57, SSD-21 (DeMerritt Direct).
[598] Ex. 4, Vol. 3, Doc. 5 at 16 (Application).
[599] Ex. 416 at 35 (St. Pierre Direct).
[600] Ex. 416 at 39 (St. Pierre Direct).
[601] Ex. 45 at 17-18 (DeMerritt Rebuttal); Ex. 417 at 26-27 (St. Pierre Surrebuttal).
[602] Ex. 45 at 17-18 (DeMerritt Rebuttal); Ex. 417 at 26-27 (St. Pierre Surrebuttal).

The Administrative Law Judge also recommends that the Commission adopt the Department's other recommendations relating to CIP.

M. Mapping Project

441. In MERC's last rate case, MERC identified its original Mapping Project, which involves developing mapping systems and data MERC's field personnel use to locate lines, manage outages, determine flow modeling, and undertake other critical infrastructure leaks.[603] To improve the quality and utilization of the mapping systems, the Mapping Project involves verifying as-built drawing and field data.[604] This information allows MERC to verify age of pipe, materials, fittings, and the like, and will support required Department of Transportation reporting.[605]

442. The next phase of the MERC Mapping Project, which will begin in 2016, involves compiling service line documentation and information into a comprehensive database. This step is the necessary prerequisite to enable MERC to map its service lines in the future and to create the capability to link the data to MERC's Geographic Information System (GIS).[606]

443. MERC's Initial Filing in this proceeding included $636,108 of Mapping Project expense for the 2016 test year.[607] This amount was included in MERC's Distribution – Other Expenses (Account 880000). Like other O&M expense, the amount was based on 2014 actual costs (here, $615,800) escalated to 2016 dollars using MERC's proposed non-labor inflation measures.[608]

444. In Direct Testimony, the Department recommended that the Mapping Project costs in the test year should be reduced from $636,108 to $150,000 because the MERC estimated $150,000 to complete the remaining Mapping Project work in 2016.[609] The Department's recommendation would reduce MERC's distribution expense by $486,108 for the Mapping Project.[610]

445. In Rebuttal Testimony, MERC provided additional information regarding remaining Mapping Project costs to support the proposed costs of $636,108 included in the test year.[611] According to MERC, the Mapping Project has two phases: the gas mains portion and the gas services portion.[612] The initial $150,000 estimate provided in MERC's

[603] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Natural Gas Serv. in Minn.*, MPUC Docket No. G011/GR-13-617, INITIAL FILING, VOL. 2 DIRECT TESTIMONY AND SCHEDULES - DEMERRITT at 18-19 (Sept. 30, 2013).
[604] Ex. 14 at 6 (Kult Rebuttal).
[605] Ex. 14 at 6 (Kult Rebuttal); *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Natural Gas Serv. in Minn.*, MPUC Docket No. G011/GR-13-617, INITIAL FILING, VOL. 2 DIRECT TESTIMONY AND SCHEDULES - DEMERRITT at 18-19 (Sept. 30, 2013).
[606] Ex. 14 at 6 (Kult Rebuttal).
[607] Ex. 14 at 6 (Kult Rebuttal).
[608] Ex. 14 at 6 (Kult Rebuttal).
[609] Ex. 416 at 35, MAS-22 (St. Pierre Direct).
[610] Ex. 416 at 35, MAS-23 (St. Pierre Direct).
[611] Ex. 14 at 7-9 (Kult Rebuttal).
[612] Ex. 14 at 8 (Kult Rebuttal).

response to DOC Information Request No. 134 referred only to the gas mains portion of the project.[613] Since calculating the initial estimate, MERC determined that additional work is required to develop the Mapping Project tool to match the functionality across its GIS, requiring external contractors to load data and improve the quality of records, which results in an increase in project cost for services to approximately $200,000.[614] MERC also projected that approximately $400,000 was needed for the gas service portion of the project (Phase II) for compiling service line documentation and information in a comprehensive database.[615]

446. The Department concluded that MERC had supported $600,000 ($200,000 for mains and $400,000 for services) for inclusion in the test year, but proposed denying the remaining $36,108 requested by MERC.[616] The Department further recommended that in MERC's next rate case, MERC be required to provide detailed information regarding the status of the Mapping Project and associated costs, including: (1) a full discussion of both phases of the Mapping Project; (2) the status of the Mapping Project; (3) the actual costs by year and the reasons for variances from forecasted amounts beginning with 2016; (4) the projected costs in the test year and how determined; (5) the actual and projected costs and how determined for the year immediately before the test year; (6) the portion of that year's costs performed by external contractors by year; and (7) any other evidence to support for MERC's Mapping Project costs.[617]

447. During the evidentiary hearing, MERC agreed with the Department's recommendation to establish a test year Mapping Project cost of $600,000 (with the downward adjustment of $36,108), and with the Department's recommended reporting requirements in MERC's initial filing in its next rate case.[618]

448. No other party offered testimony regarding the Mapping Project.

449. The Administrative Law Judge finds that a 2016 test year Mapping Project cost of $600,000 is reasonable and recommends that MERC be required to provide the Mapping Project information requested by the Department in the initial filing of its next rate case.

[613] Ex. 14 at 8 (Kult Rebuttal).
[614] Ex. 14 at 9 (Kult Rebuttal).
[615] Ex. 14 at 9 (Kult Rebuttal).
[616] Ex. 417 at 25 (St. Pierre Surrebuttal).
[617] Ex. 417 at 25 (St. Pierre Surrebuttal).
[618] Tr. Vol. 1 at 129, 133 (DeMerritt).

N. Employee Changes (K&M Adjustment)

450. MERC initially proposed a K&M increase to O&M of $88,299 inflated to 2016 levels related to nine employment positions that were either partially or fully vacated in 2014.[619]

451. The Department did not agree with MERC's proposed adjustment because it unreasonably implied that MERC would have zero vacancies or turnover in 2016.[620] The Department recommended that MERC's test year distribution expenses be reduced by $88,299 for the labor cost associated with MERC's internal job vacancies.[621]

452. The OAG also disagreed with MERC's proposed adjustment because it assumes full employment for the entire year without accounting for normal turnover. The OAG recommended that MERC remove the $90,816 vacancy adjustment from its 2016 test year in this proceeding and that MERC refrain from adding costs related to unfilled positions in future rate cases.[622]

453. MERC agreed to remove $90,816 from the test year distribution expense.[623]

454. The Department agrees the $90,816 adjustment is appropriate.[624]

455. No other party filed testimony on this issue.

456. The Administrative Law Judge finds removal of $90,816 from the test year distribution expense for the K&M adjustment for internal job vacancies is appropriate and reasonable.

O. Long-Term Incentive Plan (LTIP), Restricted Stock, and Stock Options (K&M Adjustment)

457. In MERC's 2010 rate case, costs associated with MERC's LTIP, Restricted Stock, and Stock Options were disallowed.[625] Therefore, MERC is not requesting recovery of these expenses in this case, and has decreased O&M expense by $234,504 in 2015, effectively removing those costs from the 2016 proposed test year.[626]

[619] Ex. 41 at 34, SSD-6 (DeMerritt Direct).
[620] Ex. 407 at 9 (La Plante Direct).
[621] Ex. 407 at 10 (La Plante Direct).
[622] Ex. 300 at 22-23 (Lebens Direct).
[623] Ex. 45 at 27 (DeMerritt Rebuttal).
[624] Ex. 408 at 6 (La Plante Surrebuttal).
[625] *In the Matter of the Application of Minn. Energy Resources Corp. for Auth. To Increase Rates for Natural Gas Serv. in Minn.*, MPUC Docket No. G-007, 011/GR-10-977, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 29 (July 13, 2012).
[626] Ex. 41 at 36, SSD-10 (DeMerritt Direct).

458. In response to DOC Information Request No. 152, MERC informed the Department that an additional $1,087,203 should have been removed from the 2016 test year for LTIP, Restricted Stock, and Stock Options.[627]

459. The Department recommended that the Commission require MERC to reduce the test year O&M expense by $1,087,203 to reflect the updated information relating to MERC's LTIP, Stock Options, and Restricted Stock costs.[628]

460. MERC accepted this adjustment.[629]

461. No other party filed testimony on this issue.

462. The Administrative Law Judge finds a reduction in test year expense of the LTIP, Stock Options, and Restricted Stock costs by $1,087,203 is reasonable.

P. Travel and Entertainment Expense

463. In 2010, Minn. Stat. § 216B.16 was amended to include subdivision 17, which specifies the filing requirements for travel, entertainment, and other employee expenses.[630]

464. In MERC's last rate case, the Commission required that in future rate-case filings, MERC must: (1) meet the reporting requirements of Minn. Stat. § 216B.16, subd. 17, for all travel and entertainment expenses, including expenses related to employees working for MERC affiliates; and (2) allocate any costs not specific to Minnesota based on the allocation factor MERC files in its direct testimony and identify which costs have been allocated.[631]

465. In its initial filing, MERC provided the information required by Minn. Stat. § 216B.16, subd. 17, for travel, entertainment, and related expenses. MERC also provided itemized employee expenses for employees working at MERC as well as costs allocated to MERC, and identified which costs have been allocated as requested by the Commission.[632] MERC scrutinized all employee expenses and removed any expenses it believed customers may not be required to pay under Minn. Stat. § 216B.16, subd. 17, or MERC's allocation procedures.[633]

466. The Department recommended that MERC reduce Travel and Entertainment (T&E) expenses by $93,542, plus the Department-recommended inflation factors for non-labor expenses of 1.00633 for 2015 and 1.0168 for 2016, or a total of $95,716. The Department further recommended an adjustment to reduce T&E expenses by $4,729 to reflect the recommended Department inflation factors for non-labor

627 Ex. 416, MAS-18 at 2 (St. Pierre Direct).
628 Ex. 416 at 31 (St. Pierre Direct).
629 Ex. 45 at 36 (DeMerritt Rebuttal).
630 Minn. Stat. § 216B.16, subd. 17.
631 2013 MERC RATE CASE ORDER at 26.
632 Ex. 41 at 62-63 (DeMerritt Direct); Ex. 4, Vol. 3, Doc. 14 (Initial Filing); Ex. 407 at 15 (La Plante Direct)
633 Ex. 41 at 62-63 (DeMerritt Direct); Ex. 4 Initial Filing, Vol. 3, Doc. 14 (Initial Filing).

expenses. The Department adjustment for test year T&E expenses totaled $100,445 and was made to account for the exclusion of expenses that are unreasonable and unnecessary for the provision of utility service.[634]

467. MERC accepted the Department's proposed adjustment to T&E expenses with a slight adjustment to the inflation calculation. MERC agreed that the inflation adjustment was warranted, but asserted that the non-labor inflation factors of 1.00307 and 1.01104 for 2015 and 2016 should be consistent with the overall proposed inflation adjustment. MERC also stated that the additional adjustment of $4,729 recommended by the Department resulted in a double counting of reducing these costs as all of MERC's forecasted non-labor costs, including T&E, will be reduced in a global non-labor inflation adjustment. MERC proposed to reduce T&E expenses by $94,865.[635]

468. The Department agreed to a reduction in T&E expenses by $94,865.[636]

469. In Direct Testimony, the OAG recommended three adjustments to MERC's proposed T&E expenses: (1) $3,307.08 for costs associated with expenses outside of MERC's 2014 base year; (2) a reduction of $7,463.14 related to duplicate entries; and (3) $28,344.54 based on a lack of adequate business purposes for certain T&E entries. This resulted in a total recommended disallowance of $39,114.76.[637]

470. In Rebuttal Testimony, MERC indicated it did not agree with any of the OAG's three recommended adjustments.[638] MERC maintained that the expenses: were properly included in the test year; did not represent duplicate expenses; and were for business purposes.[639]

471. In Surrebuttal Testimony, the OAG reduced its proposed downward adjustment for duplicate entries from $7,463.14 to $6,917.97, but reaffirmed its $28,344.54 adjustment for failing to provide business purpose justifications and $3,307.08 for costs associated with expenses outside of 2014.[640]

472. During the evidentiary hearing, MERC indicated that while it disagreed with the premise of the OAG's recommendations, it would agree to the proposed adjustments for duplicate entries ($6,917.97) and business purposes ($28,344.54) in order to reduce the number of contested issues in this case.[641]

[634] Ex. 407 at 15-17 (La Plante Direct).
[635] Ex. 45 at 31-32 (DeMerritt Rebuttal).
[636] Ex. 408 at 8 (La Plante Surrebuttal).
[637] Ex. 300 at 25-29 (Lebens Direct).
[638] Ex. 45 at 33-35 (DeMerritt Rebuttal).
[639] Ex. 45 at 33-35 (DeMerritt Rebuttal).
[640] Ex. 302 at 7-10 (Lebens Surrebuttal).
[641] Ex. 53 at 2 (DeMerritt Testimony Summary).

473. After the completion of the hearing, MERC also agreed to the OAG's recommended reduction of $3,307.08 for T&E expense incurred during 2014, but disagreed with the OAG's basis for the adjustment.[642]

474. No other party filed testimony on this issue.

475. The Administrative Law Judge finds that, after incorporating the reductions agreed to by MERC above, MERC's T&E expenses are reasonable and should be approved in this rate case.

Q. Investor Relations Expense

476. In response to DOC Information Request No. 111, MERC stated that WBS allocated $47,917 of investor relations costs to MERC in its test year to be charged to its Minnesota ratepayers.[643]

477. The Department recommended that 50 percent of the $47,917, or $24,097, in investor relations expense be excluded from the test year based on MERC's general description of its investor relations functions, its lack of detail provided to substantiate the amounts of proposed costs for each such function, and given a prior decision of the Commission.[644] Specifically, the Department pointed to Xcel Energy's 2012 rate case where the Commission disallowed 50 percent of Xcel Energy's investor relations expenses related to regulated Minnesota electric operations.[645]

478. MERC accepted the Department's adjustment but does not agree with the premise of the adjustment. MERC asserted that these expenses are a necessary cost of providing gas service and further benefit ratepayers because they allow MERC to raise appropriate levels of cost-effective capital and thereby positively impact customer rates. MERC, however, noted that it understands that the Commission has recently approved recovery of only 50 percent of investor relations expense in previous rate cases and expects that this adjustment will ultimately be made in this proceeding.[646]

479. No other party filed testimony on this issue.

480. The Administrative Law Judge finds that an adjustment of $24,097 of costs from the 2016 test year for investor relations expense is reasonable.

[642] OAG Response to Issues Matrix at 1-2 (June 29, 2016) (eDocket No. 20166-122793-01).
[643] Ex. 407, LL-6 (La Plante Direct).
[644] Ex. 407 at 7-8 (La Plante Direct).
[645] *See In the Matter of the Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS, AND ORDER (Sept. 3, 2013) (2012 XCEL RATE CASE ORDER). The Commission did not specifically address investor relations in its Order, but provided that it was adopting the findings, conclusions, and recommendation of the Administrative Law Judge, except as set forth in its Order.
[646] Ex. 45 at 30-31 (DeMerritt Rebuttal).

R. Late Payment Revenues

481. In its Initial Filing, MERC included $750,000 of late payment revenues in the test year.[647]

482. MERC later updated actual 2015 financial results as compared to forecasted 2015 financials in its Second Supplemental Direct Testimony, explaining that 2015 late payment revenues were understated in error by $106,447 because the actual late payment revenues for the first six months of 2015 were not included in the 2015 forecast.[648] The 2015 forecast of $437,493 was therefore an error, but the error did not affect the 2016 test year because the 2016 test year amount is based on inflationary factors applied to 2014 actual revenue.[649]

483. The Department recommended that the test year late payment revenues be increased by $106,447.[650]

484. MERC did not agree with this adjustment, as the error in the 2015 forecast did not affect the 2016 test year so the difference between the 2015 forecast and 2015 actuals should not impact the test year. MERC explained that comparing the 2016 test year late payment revenues of $750,000 with the four-year average of actual late payment revenues (2012-2015) of $547,572, the 2016 test year late payment revenue forecast of $750,000 is more likely higher than 2016 actuals will reflect, to customers' benefit.[651]

485. The Department agreed with MERC's assessment and, as a result, no longer recommended an adjustment to late payment revenues.[652]

486. No other party filed testimony on this issue.

487. The Administrative Law Judge finds that no adjustment to late payment revenues is necessary.

S. Fleet Fuel Expenses

488. MERC included approximately $939,528 of fleet fuel expenses in the test year. The Company used the clearing account approach to allocate total fleet costs to regulated and non-regulated activities based on usage. MERC inflated its 2014 fleet fuel expenses by the inflation factors of 1.00864 and 1.02413 for 2015 and 2016, respectively, to arrive at the test year amount.[653]

489. The Department suggested that MERC over-estimated its test year fleet fuel expenses by using inflated 2014 data resulting in an estimated test year price-per-gallon

[647] Ex. 4, Vol. 3, Doc. 5 at 3 (Initial Filing).
[648] Ex. 44 at 22 (DeMerritt Second Supplemental Direct).
[649] Ex. 44, SSD-2 (DeMerritt Second Supplemental Direct).
[650] Ex. 407 at 4-5, LL-3 (La Plante Direct).
[651] Ex. 45 at 19 (DeMerritt Rebuttal).
[652] Ex. 408 at 3-4 (La Plante Surrebuttal).
[653] Ex. 407 at Schedules LL-11 and LL-12 (La Plante Direct).

of gasoline of $3.36. The Department recommended a reduction in MERC's test year fleet fuel expenses in the income statement by $371,260 based on the U.S. Energy Information Administration's EIA projected average price of gasoline per gallon of $2.03 for the 2016 to 2017 24-month period for the Midwest.[654]

490. MERC accepted the Department's recommendation regarding test year fleet fuel expense to reflect lower gas prices.[655]

491. No other party filed testimony on this issue.

492. The Administrative Law Judge finds that a reduction in MERC's fleet fuel expense by $371,260 to reflect lower gas prices is reasonable.

T. Employee Benefit Costs and Pension Expense

493. MERC submitted Direct Testimony regarding the amount of employee benefit costs included in the test year, including pension and OPEB. No party offered testimony on these amounts.[656]

494. In Rebuttal Testimony, MERC initially requested increases in pension and OPEB cost increases resulting from December 31, 2015, actuarial updates.

495. The Department objected to this request,[657] and the request has been withdrawn.[658]

496. The Administrative Law Judge finds that the original amounts requested by MERC for employee benefit costs and pension expense are reasonable.

U. Rate Case Expense

497. MERC forecasted total rate case expenses of $1,687,000 and proposed to amortize 87.7 percent, or $1,479,499, over a two-year period. The 87.7 percent reflects the removal of rate case expenses for MERC's non-utility business "ServiceChoice." This amortization resulted in test year expenses of $739,750, which is slightly less than the $741,065 authorized in MERC's 2013 rate case.[659]

498. The Department recommended that the Commission accept MERC's two-year amortization with a sunset provision to limit recovery to the amount approved by the Commission in this proceeding.[660]

[654] Ex. 407 at 12-13 (La Plante Direct).
[655] Ex. 45 at 31 (DeMerritt Rebuttal).
[656] Ex. 19 at 4-18 (Hans Direct).
[657] Notice of Motion and Motion *In Limine* to Exclude, in Part, Rebuttal Testimony of Christine M. Hans (May 13, 2016) (eDocket No. 20165-121313-01).
[658] Tr. Vol. 1 at 121 (DeMerritt); Ex. 53 at 1 (DeMerritt Testimony Summary); Ex. 20 (Hans Rebuttal).
[659] Ex. 41 at 17-18 (DeMerritt Direct).
[660] Ex. 407 at 9 (La Plante Direct).

499. MERC agreed with the Department's recommendation.[661]

500. No other party filed testimony on this issue.

501. The Administrative Law Judge finds that a two-year amortization period with a sunset provision to limit recovery to the amount approved by the Commission in this proceeding is reasonable in this case.

V. Regulatory Assets and Liabilities (Non-Employee Benefits)

502. MERC initially proposed to include $19,642,806 representing MERC's net regulatory assets in rate base.[662]

503. Of this amount initially proposed by MERC, the Department determined that seven asset and liability accounts, excluding pension and benefit regulatory asset and liability balances, had no prior Commission approval or supporting testimony by MERC. These accounts included: (1) Account 182015 Reg Asset–Short Term; (2) Account 182016 Reg Asset–Derivatives–Current; (3) 182517 Reg Asset–ST Offset; (4) Account 186390 Labor Loader; (5) Account 254015 Reg Liabilities Derivatives Long Term; (6) Account 254317 Reg Liab-Short Term Offset; and (7) Account 254400 Reg Liabilities Deferred Taxes.[663]

504. The Department recommended that Account 254400 be included in rate base because it reflects the deferred taxes related to regulatory assets and liabilities.[664]

505. The Department recommended that the remaining six account balances be excluded from 2016 test year rate base. These accounts had a total balance of $123,513, as shown in the following table:[665]

Account	Test-Year Balance
182015 Reg Asset-Short Term	($2,028,452)
182016 Reg Asset-Derivatives-Current	$121,040
182517 Reg Asset-ST Offset	$2,028,452
186390 Labor Loader	$2,473
254015 Reg Liabilities Derivatives Long Term	($2,500,611)
254317 Reg Liab-Short Term Offset	$2,500,611
Total	**$123,513**

506. MERC agreed to the exclusion of the six regulatory asset and liability accounts recommended by the Department.[666]

[661] Ex. 45 at 15-16 (DeMerritt Rebuttal).
[662] Ex. 4, Vol. 3, Doc. 2 at 7 (Initial Filing).
[663] Ex. 414 at 26-27 (Byrne Direct).
[664] Ex. 414 at 27 (Byrne Direct).
[665] Ex. 414 at 27, ACB-14 (Byrne Direct).
[666] Ex. 45 at 10-11 (DeMerritt Rebuttal).

507. No other party filed testimony on this issue.

508. The Administrative Law Judge finds that the agreement reached between MERC and the Department to exclude the six non-employee regulatory asset and liability accounts as is reasonable.

W. Lump-Sum Payouts of Pension Plan

509. MERC provided Direct Testimony suggesting that a lump-sum payout to employees to close the pension plan could "de-risk" these plans under appropriate future circumstances, assuming regulatory support.[667]

510. The Department noted that MERC did not include a specific proposal for a lump-sum payout as part of its rate case application. As a result, there is no specific proposal to evaluate in this case. In addition, the Department was not convinced that offering a lump-sum payout window would justify regulatory treatment. In order to justify regulatory treatment, the Department suggested MERC would need to show that this transaction would have a net benefit to ratepayers, is significant or unusual enough to warrant regulatory treatment, or both. The Department asserted that the Commission should not consider additional expense associated with the lump-sum offered in this proceeding.[668]

511. MERC noted that it determined that it would not be pursuing a lump-sum payout with the Commission during the 2016 test year. MERC agreed that if it pursues a de-risking event in the future, it would present a specific proposal to the Commission at that time.[669]

512. No other party filed testimony on this issue.

513. The Administrative Law Judge concludes that no decision by the Commission is needed on this issue.

IX. Rate Design

A. Rate Design Principles - Background

514. Once the Commission has determined the revenue requirements for a utility, it must then decide how to structure rates to recover the utility's revenue deficiency from various customer classes. This process is known as rate design.

515. Rate design, in contrast to the determination of the revenue requirement, is a quasi-legislative function. This step of the ratemaking process largely involves policy decisions to be made by the Commission.[670] The Commission must balance competing

[667] Ex. 17 at 24-26 (Nawrot Direct).
[668] Ex. 414 at 41-12 (Byrne Direct).
[669] Ex. 18 at 15-16 (Nawrot Rebuttal).
[670] *See St. Paul Area Chamber of Commerce v. Minn. Pub. Serv. Comm'n*, 251 N.W.2d 350, 357 (Minn. 1977); MERC'S 2013 RATE CASE ORDER at 52.

interests and policy goals to arrive at the resolution most consistent with the broad public interest.[671]

516. The Commission has historically considered a variety of cost and non-cost factors when designing rates, including: cost of service; economic efficiency; ability to pay; continuity with prior rates; ease of understanding; ease of administration; promotion of conservation and renewable energy use; and ability to bear, deflect, or otherwise compensate for additional costs.[672]

517. The Commission has relied on the following four principles in establishing reasonable rate design:

i. Rates should be designed to allow the utility a reasonable opportunity to recover its revenue requirements, including the cost of capital;

ii. Rates should promote the efficient use of resources by sending appropriate price signals to customers, reflecting the cost of serving those customers;

iii. Rate changes should be gradual in order to limit rate shock to consumers. Rate stability and continuity are important to both the utility and the consumer. Consumers benefit by limiting rate shock associated with wide swings in rates, and utilities have fewer material rate design changes to implement; and

iv. Rates should be understandable and easy to administer. Maintaining ease in administration and understanding helps ensure that customers have a better understanding of their utility bills.[673]

518. These principles are based on the provisions of Minnesota statutes which require that rates must be reasonable and not unreasonably preferential or prejudicial either by class or by person. Rate design should favor energy conservation and the use of renewable energy to the maximum extent reasonable.[674] Doubts about the reasonableness of the rates should be resolved in favor of the consumer. [675]

519. While the Company has the burden of proving that its proposed rate increase will result in just and reasonable rates, the party seeking a change in current rate design has the burden to show that its proposed rate design change is just and reasonable.[676]

[671] 2012 XCEL RATE CASE ORDER at 5.
[672] *See St. Paul Area Chamber of Commerce*, 251 N.W.2d at 357; 2015 CPE RATE CASE ORDER at 64-65.
[673] Ex. 405 at 2-3 (Peirce Direct).
[674] Minn. Stat. §§ 216B.03, 216C.05 (2016).
[675] Minn. Stat. § 216B.03.
[676] *See* Minn. Stat. § 216B.16, subds. 4, 19 (2016); *Northwestern Bell Telephone Party v. State*, 299 Minn. 1, 216 N.W.2d 841 (1974) (noting that rates fixed by the Commission are presumed to be just and

B. Class Cost of Service Study – Disputed Item

520. Typically, the first step in determining the appropriate rate design is to conduct a Class Cost of Service Study (CCOSS). The purpose of a CCOSS is to identify, as accurately as possible, the responsibility of each customer class for each cost incurred by the utility in providing service.[677] The CCOSS is one important factor in determining how to design rates for customer classes. [678]

521. According to the 1989 Gas Distribution Rate Design Manual of the National Association of Regulatory Utility Commissioners (*NARUC Gas Manual*), the development of a CCOSS typically includes three main processes:

- First, utility costs are functionalized, or grouped, according to their purposes - normally production, storage, transportation, distribution, and other costs.
- Second, the functionalized costs are classified according to how they are incurred: (1) customer costs, which vary according to the number of customers served, not their energy use; (2) demand costs, which are sustained in order to serve the peak demand on the system, regardless of the number of customers; and (3) energy costs, which correspond to the quantity of energy produced.
- Third, the costs are allocated among the various customer classes according to each class's imposition of costs on the system.[679]

522. The CCOSS is a mathematical model. It consists of both endogenous and exogenous variables as well as a set of equations that determine the relationships between these variables. An endogenous variable (for example, the cost of service for the Residential class) is a variable that is determined by operation of the model. By contrast, an exogenous variable (such as test year costs) is one whose value is determined outside of the operation of the model.[680]

523. As a result, the cost of service calculated by the CCOSS depends not only on the model but also on the values of all the exogenous variables within the model, and the Commission's decision-making on each of these variable will impact the study results. For example, Commission decision-making on matters such as which items may be included in rate base, expenses, the appropriate sales forecast, and the appropriate rate of return, will impact the final figures developed by the model.[681]

reasonable); Minn. R. 1400.7300, subd. 5 (2015) (providing that the party proposing that certain action be taken has the burden of proof unless the substantive law provides a different burden or standard).

[677] Ex. 409 at 3 (Zajicek Direct).

[678] Ex. 409 at 3-4 (Zajicek Direct).

[679] Ex. 409 at 4-6 (Zajicek Direct).

[680] Ex. 409 at 6-7 (Zajicek Direct).

[681] Ex. 409 at 8 (Zajicek Direct).

524. In MERC's last rate case, the Commission accepted MERC's CCOSS but ordered MERC to submit two CCOSSs in this rate case – one based on the "zero-intercept" method, and another based on the "minimum-size" method.[682] The Commission required MERC to file the two different CCOSS analyses because the minimum-size CCOSS can be a valuable way to check the results of the zero-intercept CCOSS.[683] The two methods use different approaches to classifying distribution system costs.[684]

525. The Commission also required MERC to take the following measures to improve its analysis in its next rate case:

- collect data on additional variables that impact the unit cost of mains installation;
- avoid aggregating or averaging data and use data at the finest level reasonable;
- check ordinary-least-squares (OLS) regression assumptions and correct for violations;
- make any future zero-intercept analysis more transparent to ensure that MERC's work can be easily replicated.[685]

526. Consistent with the Commission's order in the last rate case, MERC submitted two CCOSSs -- a minimum-size study and a zero-intercept study -- for the 2016 proposed test for its Minnesota service territory.[686]

1. Background Regarding Distribution Cost Classification

527. Because the distribution system of a gas utility is jointly used by all customer classes, it is difficult to classify the costs of the distribution system with precision. Instead, the distribution system components are estimated using a CCOSS classification method. To assign the distribution costs among the different classes, the Commission considers the classification methods in the record and decides which method or methods is most reasonable.[687]

528. The choice of classification method can have a significant impact on the final CCOSS results because distribution system costs are substantial part of a gas utility's costs.[688]

[682] 2013 MERC RATE CASE ORDER at 47; *see also* Minn. R. 7825.4300(C) (2015) (requiring the filing of a CCOSS with a rate case application).
[683] 2013 MERC RATE CASE ORDER at 47.
[684] Ex. 409 at 15 (Zajicek Direct).
[685] 2013 MERC RATE CASE ORDER at 47.
[686] Ex. 34 at 14, 16 (Hoffman Malueg Direct).
[687] 2015 CPE RATE CASE ORDER at 48.
[688] *See* Ex. 304 at 7, 14 (Nelson Direct).

529. MERC recommended that its zero-intercept study be used as the CCOSS in this case to classify its distribution main investment for purposes of setting rates in this proceeding. The Department supported the use of MERC's zero-intercept analysis as reasonable.[689] The OAG, however, proposed that the Commission utilize another CCOSS method, known as the Basic System method, along with MERC's CCOSS results.[690] The OAG also recommended that the Commission require MERC to file at least two CCOSS in its next rate case, including a Basic System CCOSS and an Average and Excess CCOSS.[691]

2. MERC's CCOSS

530. As noted above, MERC filed both a minimum-size method CCOSS and a zero-intercept method CCOSS in this rate case. Both the minimum-size method and the zero-intercept method are forms of a Minimum System study. The overall goal of the Minimum System study is to determine how distribution plant investments should be classified, by determining how much of the distribution system exists to serve the following two functions:

- being capable of delivering service to customers' residences or businesses (customer costs), and
- ensuring that the distribution system is large enough to provide reliable service (demand costs).[692]

531. A Minimum System study uses a theoretical approach to determine the smallest sized distribution pipe that would be needed to service a gas customer. That theoretical minimum, or smallest sized pipe, is then considered to be the minimum amount of fixed investment that would be required by a utility to serve a customer (customer cost). The remaining portion of the system is considered to theoretically vary given a customer's demands placed on the distribution system (demand cost).[693] A Minimum System method derives the classification percentage split between customer costs and demand costs to be utilized within a CCOSS against distribution mains.[694]

532. The minimum-size method and the zero-intercept method are the two primary Minimum System study methods used by analysts to estimate the cost of the minimum system. The minimum-size method estimates what it would cost to rebuild the current distribution system using the smallest pipe the utility currently installs.[695] The zero-intercept method uses regression analysis to determine the cost of a hypothetical distribution system with zero-inch mains to estimate what portion of the systems costs would be needed regardless of whatever level of demand for gas customers had.

[689] Ex. 411 at 1 (Zajicek Sur-Surrebuttal).
[690] Ex. 304 at 29 (Nelson Direct).
[691] Ex. 304 at 29 (Nelson Direct)
[692] Ex. 409 at 14 (Zajicek Direct).
[693] Ex. 34 at 16 (Hoffman Malueg Direct).
[694] Ex. 34 at 17 (Hoffman Malueg Direct).
[695] Ex. 409 at 15 (Zajicek Direct).

Essentially both methods seek to determine what portion of the distribution costs are for infrastructure not related to demand for gas.[696]

533. Each approach has advantages and disadvantages. Typically, the minimum-size method is less accurate than the zero-intercept method because it tends to overstate the amount of the system costs attributable to the hypothetical no-load system (customer costs), and underestimates the portion attributable to customer demand (demand costs). This result occurs because using a minimum-sized pipe allows for some small amount of demand to be met using a minimum-size system. This over-statement of demand costs can be accounted for, however, through a demand adjustment, which if correctly implemented, makes both methods comparable. The zero-intercept method could also be inferior in cases where insufficient data is available to allow regression analysis to give significant results. Whether one method is superior to the other depends on the data obtained and how each method is performed.[697]

534. In conducting both its minimum-size CCOSS and its zero-intercept CCOSS, MERC applied general principles of cost allocation from the *NARUC Gas Manual* and the American Gas Association to arrive at estimated costs of service for the various customer classes and individual components of cost within each customer class.[698]

535. For its minimum size study, MERC used historical records for MERC's distribution grid that contained information on the amount of pipe laid, the size of pipe (diameter), and the cost for the project at the time of construction, as well as a number of other variables. The Company then inflated the costs of these projects using the Handy-Whitman index to normalize the cost data into current replacement costs, such that the data can be directly and sensibly compared to each other in a cost analysis.[699] MERC used a two-inch pipe for the minimum-sized pipe for both plastic and steel installations to determine the Total Minimum System Cost.[700] MERC divided the Total System Minimum Cost by the Total System Cost to determine the percentage of the minimum system, or fixed investment cost, which was 74.12 percent. According to this analysis, 74.12 percent of the costs of the distribution mains should be classified as customer costs, and the remaining 25.88 percent should be classified as demand costs.[701]

536. MERC did not make a demand adjustment to its results even though its two-inch minimum pipe could be carrying some load (a/k/a demand). MERC's witness, Ms. Hoffman Malueg, stated that MERC did not know how to calculate such an adjustment.[702]

[696] Ex. 409 at 15 (Zajicek Direct); Ex. 34 at 26 (Hoffman Malueg Direct).
[697] Ex. 409 at 15-16 (Zajicek Direct); *see also* Ex. 34 at 28-29 (Hoffman Malueg Direct) (stating her view that the zero-intercept study is "slightly more accurate than a minimum-size study because the zero-intercept method is a better reflection of fixed cost and performing a zero-intercept study requires considerably more calculations and company-specific data).
[698] Ex. 34 at 9-12 (Hoffman Malueg Direct).
[699] Ex. 34 at 20-23 (Hoffman Malueg Direct); Ex. 409 at 16-17 (Zajicek Direct).
[700] Ex. 34 at 23-24 (Hoffman Malueg Direct).
[701] Ex. 34 at 24 (Hoffman Malueg Direct).
[702] Ex. 34 at 19-20 (Hoffman Malueg Direct).

537. The Department's witness, Mr. Zajicek, confirmed that MERC's calculations of its minimum-size method were accurate. He concluded that, given the available data, MERC's minimum-size method was satisfactory and MERC followed the NARUC Gas Manual's methodology, except that MERC did not include a demand adjustment.[703]

538. Without a correctly-implemented demand adjustment, MERC's minimum size CCOSS likely overestimated the customer costs and underestimated the demand costs. As a result, MERC did not propose to use the results of the minimum-size method to determine rates.[704]

539. Instead, MERC proposed to use the results of its zero-intercept CCOSS. MERC's zero-intercept CCOSS showed that 63 percent of the costs are attributed to customer costs with the remaining 37 percent attributable to demand costs.[705] These results show a lower percentage of costs attributable to customer costs than the minimum size results, which attributed 74.12 percent of the costs as customer costs.

540. The zero-intercept method has the same goals as the minimum-size method, but uses statistical analysis based on the system cost data to identify the costs, pipe size, length of pipes, and other information, and to model the cost of distribution mains. The intercept value is determined by formulating a regression equation that relates pipe cost and pipe size to estimate the costs of a zero-sized pipe. This intercept value is applied against all quantities of the distribution mains currently installed by the utility to arrive at a Total Minimum System Cost. Similar to the minimum-size method, by dividing the Total Minimum System Cost by the Total System Cost, it is possible to derive the percentage of the system that is considered to be attributable to the hypothetical no-load system (customer costs) and the portion attributable to customer demand (demand costs).[706]

541. MERC witness, Ms. Hoffman Malueg, testified that MERC's zero-intercept study is slightly more accurate than its minimum-size study because the zero-intercept method is a better reflection of fixed cost and a zero-intercept study requires considerably more calculations and company-specific data. She noted there is more involvement, time, and effort involved in conducting a zero-intercept study.[707]

542. In conducting its zero-intercept study, MERC took measures to comply with the requirements in the Commission's last order intended to improve the accuracy of MERC's zero-intercept analysis. MERC detailed those steps in the Direct Testimony of Ms. Hoffman Malueg.[708] As noted above, those requirements included:

[703] Ex. 409 at 18 (Zajicek Direct); Ex. 409A at MZ-4, MZ-5 (Zajicek Direct Attachments).
[704] *See* Ex. 34 at 18-19, 79 (Hoffman Malueg Direct).
[705] Ex. 34 at 49, 79 (Hoffman Malueg Direct); Ex. 4, Vol. 3, Doc. 12, Schedule 5 (Initial Filing); Ex. 35 at 4 (Hoffman Malueg Rebuttal).
[706] Ex. 409 at 19 (Zajicek Direct).
[707] Ex. 34 at 28-29 (Hoffman Malueg Direct).
[708] Ex. 34 at 30-69 (Hoffman Malueg Direct); Ex. 409 at 10 (Zajicek Direct).

- collect data on additional variables that impact the unit cost of mains installation;
- avoid aggregating or averaging data and use data at the finest level reasonable;
- check OLS regression assumptions and correct for violations; and
- make any future zero-intercept analysis more transparent to ensure that MERC's work can be easily replicated.[709]

543. In Direct Testimony, the Department's witness, Mr. Zajicek, stated he obtained data from MERC to recreate the various regression models conducted as part of MERC's zero-intercept analysis and obtained very similar results to those presented by the Company.[710] Mr. Zajicek noted while MERC was ordered to avoid aggregating data, it became necessary to use average current cost by pipe diameter to get statistically significant results during the course of the regression analysis. Mr. Zajicek confirmed that models that did not use average current cost by pipe diameter were not statistically valid. Mr. Zajicek also noted that results of MERC's model agree theoretically with the NARUC Electric Manual, in that these results were similar to the results of the minimum-size method except with a somewhat lower amount of costs attributable to the no-load system. For these reasons, Mr. Zajicek was not concerned about the aggregation of data.[711]

544. Based on his review of the MERC's zero-intercept analysis, the Department's witness, Mr. Zajicek, concluded that MERC's zero-intercept study results and methodology were reasonable. He also concluded that the classification and allocation of the functionalized accounts were generally consistent with the *NARUC Gas Manual* and cost-causation principles.[712]

545. The OAG, on the other hand, did not agree that MERC's zero-intercept analysis was reasonable. The OAG asserted that MERC made a number of mistakes in its zero-intercept regression analysis and did not comply with the Commission's 2013 order. For example, the OAG asserted the MERC improperly eliminated certain independent variables from the analysis. In addition, the OAG asserted that MERC improperly used averages and MERC's analysis violates the OLS assumptions. For these reasons, the OAG recommended that the zero-intercept analysis be given little weight when determining revenue apportionment.[713]

546. In Rebuttal Testimony, Department responded to the OAG's assertions that MERC had failed to comply with the 2013 order requirements. The Department's witness disagreed with the OAG's view that MERC improperly eliminated certain variables. Mr.

[709] 2013 MERC RATE CASE ORDER at 47.
[710] Ex. 409 at 20 (Zajicek Direct).
[711] Ex. 409 at 20-21 (Zajicek Direct).
[712] Ex. 409 at 20-21 (Zajicek Direct).
[713] Ex. 304 at 25 (Nelson Direct).

Zajicek did, however, share the OAG's concern that MERC's zero-intercept study may have violated the OLS assumptions.[714]

547. MERC responded to the OAG's criticisms of MERC's zero-intercept CCOSS. Ms. Hoffman Malueg disagreed with the OAG's assertion that MERC should have included additional independent variables in MERC's regression equation. She noted that when additional independent variables were included, none of the models produced valid or reasonable regression equations. She also discussed MERC's attempts at utilizing un-averaged and un-aggregated data in its zero-intercept model. Finally, she maintained that MERC provided sufficient information to show that its regression equation meets OLS assumptions.[715]

548. Based on MERC's Surrebuttal Testimony and his own further review, the Department's witness, Mr. Zajicek, concluded that the results of MERC's zero-intercept model were reasonable to consider in this proceeding.[716] Mr. Zajicek noted that while he "still had some concerns about the OLS assumptions within MERC's zero-intercept study," he came to the "conclusion that these issues would not bias the coefficient estimates, and thus would not cause the CCOSS results based on it to be inaccurate."[717] As a result, the Department concluded that the Commission should accept MERC's zero-intercept CCOSS as a useful tool in setting rates in this proceeding.[718]

549. The OAG's witness, Mr. Nelson, also reviewed the analysis provided by MERC in Ms. Hoffman Malueg's Surrebuttal Testimony. He did not find the analysis helpful in terms of evaluating the OLS issue.[719] The OAG continued to recommend that MERC's zero-intercept analysis be given little weight.

550. In addition, as discussed below, the OAG raised a number of concerns with the use of the Minimum System method. As a result, the OAG recommended that the Commission not rely solely on MERC's CCOSS in determining revenue apportionment but consider multiple models.[720]

3. The OAG's Alternative CCOSS Analysis

551. The OAG recommended that the Commission consider the Basic System method of allocating distribution main costs in addition to the Minimum System method used by MERC, and place more weight on the Basic System CCOSS results. The OAG

[714] Ex. 410 at 12-14 (Zajicek Rebuttal); Ex. 411 at 2 (Zajicek Sur-Surrebuttal).
[715] Ex. 35 at 47-51 (Hoffman Malueg Rebuttal).
[716] Ex. 411 at 1 (Zajicek Sur-Surrebuttal). Mr. Zajicek stated that he had a concern about that there was "a violation of the independence of errors OLS assumptions." His concern was addressed by because: (1) autocorrelation would not bias coefficient estimates; and (2) the potential for a violation of the homoscedasticity assumption was not of concern in this situation, because heteroscedasticity does not bias the portion of the zero-intercept study results that are used in the Class Cost of Service Study. Ex. 411 at 2-5 (Zajicek Sur-Surrebuttal).
[717] Ex. 421 (Zajicek Opening Statement); Tr. Vol. 2 at 32-33 (Zajicek).
[718] Ex. 411 at 1, 8 (Zajicek Sur-Surrebuttal).
[719] Tr. Vol. 1 at 209-211 (Nelson).
[720] Ex. 304 at 16-20, 28 (Nelson Direct).

also recommended that in future cases, the Commission also consider the "Average and Excess" method for MERC. The OAG noted that these three methods vary by how they classify and allocate distribution costs.[721]

552. The Basic System method differs from the Minimum System method in one key way: it classifies distribution mains as 100 percent demand costs and no costs of the distribution main investment are considered to be customer costs.[722]

553. The OAG offered two theories to support the Basic System CCOSS method. The first is that when distribution mains are installed they are engineered to meet peak demand reliably and safely, and a main will not be installed if it is incapable of serving peak demand. For this reason, the Basic System assumes that "the cost of distribution mains are caused by the requirement to meet peak demand."[723] A second theory for the Basic System method is that "demand costs are the fixed costs that a utility incurs to be ready to provide service." Mr. Nelson cited Alfred Kahn, a well-known regulatory economist, as characterizing demand costs in this manner.[724] Essentially, the theory assumes that the distribution system was built only to meet peak demand of the entire system, and not to deliver service to customers.[725]

554. Mr. Nelson maintained that the Basic System method is more reasonable than the Minimum System method for several reasons. First, in Mr. Nelson's view, the Basic System method more accurately reflects cost causation because "[d]emand causes the need for distribution main investments, and the distribution system must be engineered to meet safety and reliability requirements in order to serve peak demand."[726] Second, the Basic System approach does not rely on splitting distribution main costs between demand and customer costs whereas the Minimum System approach requires subjective assumptions to achieve this split.[727]

555. The OAG asserted that "numerous academic and industry experts" have criticized the Minimum System approach, relied upon by MERC. The OAG claimed that "there is no agreed upon or clear way to determine costs causation." As a result, the OAG maintained that it would be more reasonable to consider more than one CCOSS in determining revenue apportionment in this case.[728]

[721] Ex. 304 at 5 (Nelson Direct).
[722] Ex. 304 at 7 (Nelson Direct).
[723] Ex. 304 at 7 (Nelson Direct).
[724] Ex. 304 at 7 (Nelson Direct).
[725] Ex. 410 at 2 (Zajicek Rebuttal).
[726] Ex. 304 at 8 (Nelson Direct).
[727] Ex. 304 at 8, 17 (Nelson Direct).
[728] Ex. 307 at 2 (Nelson Surrebuttal); Ex. 304 at 19-22 (Nelson Direct) (citing Bonbright, *Principles of Public Utility Rates* (1961); Jim Lazar, currently Senior Advisor at RAP, 1992 analysis for the Arizona Corporation Commission; 2000 RAP Report).

556. The OAG maintained that utilities prefer to use the Minimum System method because it allows the utility to maximize the portion of costs that are classified and allocated as customer costs.[729]

557. Based on these alleged short-comings of the Minimum System method and because CCOSS is "an inherently imprecise tool," the OAG recommended that the Commission consider more than one CCOSS model to inform rates.[730] According to Mr. Nelson, considering multiple CCOSS models allows the Commission to view a range of results rather than relying on an individual analyst's view of the most reasonable CCOSS.[731] In addition, the OAG maintained that there is no one correct way to allocate plant that is used to provide several different types of service.[732]

558. The OAG also asserted that "regulators in other jurisdictions often consider several CCOSS results in making their apportionment decisions." Similarly, the OAG claimed that about half the commissions in the county do not classify any portion of distribution main costs as customer costs.[733]

559. The OAG noted that the Basic System approach produces very different CCOSS results than MERC's zero-intercept analysis. The OAG's analysis showed that, if each class were given a rate increase equal to MERC's overall request of 5.47 percent, the Residential Classes (NNG and Consolidated) would be paying above their cost of service.[734] Under MERC's zero-intercept CCOSS, however, the Residential Classes would be paying less than their cost of service.[735]

560. MERC disagreed with the OAG's proposal to classify distribution main investment and costs as 100 percent demand using the Basic System method[736] and recommended utilizing the zero-intercept CCOSS because it recognizes both demand- and customer-cost drivers.[737] MERC asserted that classifying distribution main costs solely as demand-driven, as the Basic System method does, would ignore that the total installed footage of distribution mains is influenced by the need to expand the distribution system in order to connect customers.[738]

[729] Ex. 304 at 18 (Nelson Direct).
[730] Ex. 304 at 4 (Nelson Direct).
[731] Ex. 304 at 4 (Nelson Direct).
[732] Ex. 304 at 6 (Nelson Direct) (citing Charles R. Phillips, Jr., *The Regulation of Public Utilities* (1993) at 438).
[733] Ex. 304 at 4, 16 (Nelson Direct); Ex. 56 (OAG Response to MERC IR 18).
[734] Ex. 304 at 10, 13-14 (Nelson Direct).
[735] Ex. 304 at 14 (Nelson Direct).
[736] Ex. 35 at 7 (Hoffman Malueg Rebuttal).
[737] Ex. 35 at 16 (Hoffman Malueg Rebuttal).
[738] Ex. 35 at 28 (Hoffman Malueg Rebuttal).

561. MERC asserted that the Minimum System method is frequently used and is well accepted.[739] According to MERC, about half the commissions in the country use a form of the Minimum System approach to classify distribution system costs.[740]

562. The Department also disagreed with OAG's suggestion that the Basic System method be used to classify and allocate the costs of MERC's distribution system. The Department's witness, Mr. Zijicek, explained that assigning 100 percent of these costs to demand is inconsistent with MERC's gas distribution system because the distribution system is designed not just to meet peak demand. The distribution system is also designed to be capable of delivering service to each customer's home or business, rather than requiring customers to take it on themselves to obtain the product. Because delivery of natural gas to homes and businesses is important, it is necessary for the CCOSS to recognize the customer-driven cost of the distribution system.[741]

563. The Department noted Minimum System studies (such as the zero-intercept CCOSS) are used because they address the dual purposes of the distribution system by determining what portion of the distribution system is needed to serve peak load and what portion is needed to deliver service to each customer.[742] The Department indicated that the Minimum System study approach is supported by the *NARUC Gas Manual*.[743]

564. The *NARUC Gas Manual* defines "demand" costs as those incurred to serve peak demand on the system that do not directly vary with the number of customers. "Customer" costs, meanwhile, are defined as costs that vary with the number of customers.[744] The Department's witness, Mr. Zajicek, emphasized that there are design elements for the distribution system that are implemented due to the number of customers, not just their peak demand, and therefore the creation of a system involves customer costs.[745] Because the Basic System method does not account for this important aspect of the distribution system, the Department did not recommend approving the use of the Basic System to classify and allocate the distribution system in the CCOSS.[746]

565. In Surrebuttal Testimony, the OAG disagreed with the view that the Minimum System study better reflects cost causation.[747] In support of its position, the OAG's witness, Mr. Nelson, again referenced economist Alfred Kahn's view that capacity costs are caused by the utility's ability to serve on demand. Mr. Nelson also argued that this approach is more consistent with engineering principles.[748] In addition, the OAG continued to advocate that use of more than one CCOSS approach is warranted. The OAG maintained that the Basic System is superior to the Minimum System but recognized

[739] Ex. 35 at 19 (Hoffman Malueg Rebuttal).
[740] Ex. 35 at 19 (Hoffman Malueg Rebuttal).
[741] Ex. 410 at 2 (Zajicek Rebuttal).
[742] Ex. 410 at 3-4 (Zajicek Rebuttal).
[743] Ex. 410 at 3 (Zajicek Rebuttal).
[744] Ex. 410 at 4 (Zajicek Rebuttal) (citing *NARUC Gas Manual* at 22-24).
[745] Ex. 410 at 4 (Zajicek Rebuttal).
[746] Ex. 410 at 4 (Zajicek Rebuttal).
[747] Ex. 307 at 1 (Nelson Surrebuttal).
[748] Ex. 307 at 2-6 (Nelson Surrebuttal).

that disagreement exists, and therefore recommended consideration of multiple approaches.[749]

4. Analysis of CCOSS Methods for Use in this Case

566. The question before the Administrative Law Judge is whether the record best supports use of MERC's zero-intercept CCOSS results or whether the record best supports consideration of the Basic System CCOSS results along with the Minimum System CCOSS results as recommended by the OAG.

567. Based on the record as a whole, the Administrative Law Judge concludes that the Basic System approach is not supported by the record in this case, and MERC's zero-intercept CCOSS is the most reasonable CCOSS for use in classifying the cost of MERC's distribution mains.

568. As the Department persuasively explained, the distribution system has dual purposes: to meet peak demand and to be capable of delivering service to people's homes and business. In addition, as noted by MERC, the total installed footage of its distribution mains is influenced by the need to expand the distribution system in order to connect customers. As a result, the record is clear that distribution mains have both demand *and* customer costs.

569. Because the Basic System CCOSS assigns 100 percent of distribution main costs to demand and zero percent to customer costs, the Basic System approach does not accurately reflect cost causation on MERC's distribution system. Similarly, the Basic System method fails to reflect that MERC's natural gas system has a delivery and service function, not just a demand function. For these reasons, the record does not support use of the Basic System to classify the costs of MERC's system.

570. The record also demonstrates that MERC's zero-intercept CCOSS more accurately reflects cost causation than any other CCOSS in the record. While certainly no CCOSS is perfect, the zero-intercept CCOSS considers both the demand and customer purposes of the distribution mains. In addition, the zero-intercept CCOSS is more accurate than the minimum-size CCOSS because it does not require a demand adjustment as discussed above in paragraph 533.

571. In addition, after a thorough review of the data and the underlying assumptions used by MERC, the Department's witness, Mr. Zajicek, testified credibly that MERC's zero-intercept analysis is a useful tool for purposes of setting rates in this proceeding. While the OAG's witness, Mr. Nelson, disagreed with this assessment, Mr. Zajicek persuasively explained why the OAG's concerns regarding the use of variables, aggregation of data, and OLS assumptions were not well founded or would not affect the accuracy of the results.[750] For these reasons, the Administrative Law Judge

[749] Ex. 307 at 1 (Nelson Surrebuttal).
[750] Ex. 409 at 3-21 (Zajicek Direct); Ex. 410 at 2-4 (Zajicek Rebuttal); Ex. 411 at 2-5 (Zajicek Sur-Surrebuttal); Tr. Vol. at 32-33 (Zajicek).

agrees with the Department that MERC's zero-intercept CCOSS is reasonable and should be accepted in this case.

572. In addition, contrary to the OAG's suggestion, using more than one CCOSS model will not necessarily produce better results. The results will depend on whether the model or models used accurately reflect cost causation. As discussed above, the record in this case shows that the Basic System model does not accurately reflect cost causation for MERC's distribution mains. As a result, the OAG's suggestion that the Commission consider both the Basic System CCOSS and MERC's Minimum System CCOSS results will not produce a more accurate allocation of costs for MERC's distribution mains.

573. For these reasons, the Administrative Law Judge recommends that the Commission accept MERC's zero-intercept analysis. Further, the Administrative Law Judge recommends against using the Basic System approach in this case.

574. The Administrative Law Judge recognizes that in the recent CenterPoint rate case, the Commission decided not to rely solely on CenterPoint's minimum-size CCOSS but instead decided to consider both CenterPoint's CCOSS and the OAG's three alternative CCOSSs (including the Alternative Minimum System, Basic System, and Peak and Average) in making a revenue-apportionment decision.[751] In that case, CenterPoint relied on a minimum-size CCOSS, not a zero-intercept CCOSS. In addition, the Commission was not able to compare the results of CenterPoint's minimum-size CCOSS against a zero-intercept analysis to check the reasonableness of the minimum-size study.[752] In this case, by contrast, MERC is relying on its zero-intercept CCOSS, which can be compared to its minimum-size CCOSS. Also, the record was fully developed on the limitations of the Basic System method as applied to MERC. For these reasons, the Administrative Law Judge concludes that the record in this case is factually distinguishable from the record in the CenterPoint case, and the CenterPoint decision does not require consideration of the Basic System CCOSS in this case.

575. The Commission, however, may want to consider opening a generic docket for all gas utilities to address in greater detail the complex issues raised in this docket and the CPE docket regarding cost allocation of gas distribution system costs.

[751] 2015 CPE RATE CASE ORDER at 53.
[752] 2015 CPE RATE CASE ORDER at 53.

5. Use of the Average and Excess Method and the Basic System Method in the Next Rate Case

576. As noted above, the OAG also recommended that the Commission require MERC to file a CCOSS using the "average and excess" method in its next rate case as well as a Basic System CCOSS.[753]

577. According to the OAG, the Average and Excess CCOSS allocates the demand portion of distribution mains based on a commodity allocator, such as annual therm consumption or average demand, and non-coincident peak demand. The theory behind the Average and Excess model is that a portion of system costs are caused by peak demand and that others are caused by how the system is utilized, which is related to throughput, or commodity, usage. The Average and Excess CCOSS can be "characterized as a partial energy weighting method" because it allocates based on a commodity allocator but does not classify distribution mains as a commodity cost.[754]

578. The OAG requested that the Commission consider an Average and Excess CCOSS because it believes that a CCOSS that allocates distribution cost based partially on the throughput of the customer should be in the record.[755]

579. The Department noted that the Average and Excess approach cannot be used as the only analytic tool for creating a CCOSS because the Average and Excess approach is an *allocation* method to be used only after the demand portion of distribution mains is determined. It is necessary to use a *classification* method, such as a Minimum System study or the Basic System method, to first determine which portion of costs are demand-related.[756]

580. This method, if it were adopted in conjunction with the Basic System classification method, would, in essence, allocate all of the costs of the distribution system based on a combination of each customer class's non-coincident peak demand and the amount of natural gas used by each class of customers.[757] Currently MERC uses peak month capacity of firm sales rate schedules to allocate costs of the demand component of the distribution system. The Average and Excess method would include a commodity allocator and non-coincident peak, in contrast to the system peak demand allocator MERC uses.[758]

581. System peak demand and non-coincident peaks of customer classes are very different. System peak demand is the maximum amount of natural gas that flows through the system to serve the needs of customers using natural gas at the peak. Non-coincident peaks of customer classes are the maximum amounts of natural gas that flow

[753] Ex. 304 at 5, 29 (Nelson Direct).
[754] Ex. 304 at 10-11 (Nelson Direct) (quoting the NARUC Electric Manual at 49).
[755] Ex. 304 at 11-12 (Nelson Direct).
[756] Ex. 410 at 5 (Zajicek Rebuttal).
[757] Ex. 410 at 5 (Zajicek Rebuttal).
[758] Ex. 410 at 6 (Zajicek Rebuttal).

through the system for each class of customers, whenever those occur, whether or not those demands coincide with the system peak.[759]

582. The Department's witness, Mr. Zajicek, identified a number of problems with the proposed Average and Excess method. First, he observed that the cost of each customer class' annual use of the system is already reflected in the CCOSS. Specifically, energy costs, including the costs of natural gas and operation and maintenance expense are appropriately allocated to each customer class based on the annual amount of natural gas that each class uses (the energy allocator). A concern with the proposed Average and Excess method is that if, in addition, costs of the demand portion of the distribution system are allocated to customer classes based in part on the annual amount of natural gas used by each customer class, too little of the demand costs would be allocated to a customer class that demands a large amount of energy at the system peak but uses relatively less natural gas over the course of the year.[760]

583. Similarly, according to Mr. Zajicek, this approach may allocate too much of the costs of the size of the distribution system to a customer class that uses relatively equal amounts of natural gas throughout the year, especially if such a class is curtailed from taking service as an interruptible customer during the system peak.[761]

584. For these reasons, the Department disagreed with the proposal to use the Average and Excess allocation method in MERC's next rate case unless it can be shown reasonably to reflect how costs of the distribution system are incurred.[762]

585. MERC also disagreed with the OAG's recommendation to file a CCOSS using the Average and Excess approach in future rate cases. MERC asserted that the Minimum System CCOSS is the appropriate model to use given the nature of MERC's system. MERC also stated that it already provides a proxy that is akin to the Average and Excess method; so a requirement to file an Average and Excess model would be a duplication of what is already being provided by MERC with existing, available data.[763]

586. The Administrative Law Judge concludes that the Department has raised valid questions about whether the Average and Excess method reasonably reflects how costs of the distribution system are incurred. In addition, MERC stated that it provides a proxy that is akin to the Average and Excess method. For these reasons, the Administrative Law Judge recommends that the Commission not adopt the OAG's recommendation that MERC be required to file a CCOSS using the Average and Excess method in its next rate case.

[759] Ex. 410 at 7 (Zajicek Rebuttal).
[760] Ex. 410 at 8 (Zajicek Rebuttal).
[761] Ex. 410 at 8 (Zajicek Rebuttal).
[762] Ex. 410 at 8-9 (Zajicek Rebuttal).
[763] Ex. 35 at 31 (Hoffman Malueg Rebuttal).

587. Similarly, the Administrative Law Judge does not recommend the Commission require MERC to file a Basic System CCOSS in its next rate case because of the limitations of that model with regard to cost causation of the distribution system.

588. Instead, the Administrative Law Judge recommends that MERC be required to file a zero-intercept CCOSS and a minimum-size CCOSS in its next rate case, as well as any other CCOSS(s) ordered by the Commission at the completion of any generic proceeding undertaken by the Commission.

6. Former IPL Customer Considerations in the CCOSS

589. MERC did not conduct a separate cost of service study for serving the customers who were formerly served by IPL and are now served by MERC.[764] As noted above, on May 1, 2015, MERC acquired IPL's assets and the former IPL customers are now being served by MERC.[765]

590. The OAG maintained that MERC improperly assumed that the customers in the former IPL area have the same costs as other MERC customers. According to OAG witness, Mr. Nelson, the former IPL service area "likely has different customer density, age of system, [and] load profiles, among other characteristics."[766]

591. For this reason, the OAG recommended that no weight be given to MERC's CCOSS with respect to the costs caused by the former IPL customers. Instead, the rates for the former IPL area should be decided on policy considerations, without considering the cost of service.[767]

592. MERC disagreed with the OAG's position. MERC witness, Ms. Hoffman Malueg, explained that MERC's CCOSS accounted for the load profiles of the former IPL customers within its CCOSS.[768] Ms. Hoffman Malueg also disagreed with the OAG's assertion that the former IPL customers have different costs than MERC's other customers because the former IPL customers are relatively homogenous with respect to MERC's NNG rate schedules.[769]

593. The Administrative Law Judge finds that MERC has properly accounted for the former IPL customers in its CCOSS. The Administrative Law Judge is unaware of any instance where the Commission has required a separate CCOSS for a newly acquired area.[770] Furthermore, the OAG does not dispute that MERC's former IPL customers are currently paying well below their cost of service.[771]

[764] Ex. 304 at 27 (Nelson Direct).
[765] Ex. 39 at 19 (Lee Rebuttal).
[766] Ex. 304 at 27 (Nelson Direct).
[767] Ex. 304 at 27-28 (Nelson Direct).
[768] Ex. 35 at 52, Schedule JCHM-R3 (Hoffman Malueg Rebuttal).
[769] Ex. 35 at 52-54, Schedule JCHM-R3 (Hoffman Malueg Rebuttal).
[770] *See* Ex. 304 at 27-28 (Nelson Direct).
[771] *See* Ex. 304 at 38 (Nelson Direct); OAG Initial Br. at 47 (June 29, 2016) (eDocket No. 20166-122790-01).

594. The Administrative Law Judge further concludes that it is reasonable to consider MERC's zero-intercept CCOSS results as one factor in setting rates for all of MERC's customers, including MERC's customers in the former IPL service area.

7. Other Recommendations

595. As noted above, in MERC's last rate case, the Commission required MERC in this case to:

- collect data on additional variables;
- avoid aggregating data;
- check ordinary least squares regression assumptions and correct for any violations; and
- improve the transparency of its zero intercept analysis.[772]

596. The Department reviewed the information provided by MERC to address these requirements.[773]

597. With regard to data aggregation, the Department noted that MERC "attempted to avoid aggregation of data" to the extent possible. The Department, however, recommended that MERC gather and use project-level data for its zero-intercept study in its next rate case.[774]

598. MERC disagreed with the Department's recommendation on project-level data. MERC stated that it is not able to gather a sufficient amount of project-level data for adequate use within a Minimum System study.[775] In addition, MERC does not read the Commission's decision in the last rate case to require the use of project-level data.[776]

599. During the evidentiary hearing, MERC and the Department reached an agreement regarding the collection and future use of project-level data. Specifically, MERC and the Department agreed that MERC would: (1) collect project-specific data on installation footage, pipe diameter, and cost; (2) research, and as soon as possible, begin collection of distribution asset retirement at this same project-level detail; and (3) explore the use of this project-specific data in its zero-intercept CCOSS in future rate case filings.[777]

600. The Department also recommended that the Commission require MERC to provide a substantive explanation and justification of its classification and allocation

[772] 2013 MERC RATE CASE ORDER at 47.
[773] Ex. 409 at 9-13 (Zajicek Direct); Ex. 410 at 13 (Zajicek Rebuttal); Ex. 411 at 1-5 (Sur-Surrebuttal).
[774] Ex. 409 at 10 (Zajicek Direct); Ex. 410 at 17 (Zajicek Rebuttal).
[775] Ex. 36 at 12 (Hoffman Malueg Surrebuttal).
[776] Ex. 36 at 14 (Hoffman Malueg Surrebuttal).
[777] Tr. Vol. 2 at 34-35 (Zajicek); Ex. 411 at 8 (Zajicek Sur-Surrebuttal).

methods when it files its CCOSS in the next rate case.[778] MERC did not object to this recommendation.

601. The Administrative Law Judge finds the agreement reached between MERC and the Department with respect to project-level data is reasonable and recommends it be accepted by the Commission. The Administrative Law Judge also recommends that MERC be required to provide a substantive explanation and justification of its classification and allocation methods when it files its CCOSS in the next rate case.

C. Revenue Apportionment – Disputed Item

602. Once the CCOSS analysis is complete, the Commission evaluates how to apportion the approved revenue requirement among the various customer classes that receive service from the Company. The division of responsibility for producing the required revenues among the customer classes is called revenue apportionment.

603. Revenue apportionment is important because it ultimately determines the price customers are charged for their gas services.

604. There is no requirement that rates for all classes be equal, but any rate differences must be reasonable.[779] In addition, as discussed above in paragraph 516, the Commission has historically considered a range of cost and non-cost factors in setting rates.

605. In developing its proposed revenue apportionment, MERC considered the following goals:

- collect total revenues sufficient to allow MERC to recover its cost of operations for the test year, including a reasonable return on investment;
- reflect the cost of providing service to each customer class, as supported by MERC's CCOSS, while giving consideration to non-cost factors, e.g., value of service, where appropriate;
- provide overall revenue stability to MERC;
- encourage sound economic energy use;
- minimize cross-subsidization between rate classes;
- avoid large bill impacts or "rate shock";
- minimize bypass threats to large industrial customers;

[778] Ex. 411 at 8 (Zajicek Sur-Surrebuttal).
[779] *See* Minn. Stat. § 216B.03 (2016).

- limit the impact of the proposed rates on low-income customers; and
- provide flexibility in pricing and service conditions, which will allow MERC's natural gas services to be competitive with other energy sources.[780]

606. MERC's zero-intercept CCOSS results were its starting point for the apportionment of the retail revenue requirement among the rate classes. Other rate design goals were then considered, as noted above, such as maintaining competitive pricing, and limiting large bill impacts or "rate shock." MERC's goal was to recover as closely as possible the costs imposed by each class, while avoiding unacceptably high billing impacts.[781]

607. MERC's proposed revenue apportionment was presented in a schedule that compared test year operating revenue under present and proposed rates by customer class of service, showing the difference in revenue and percentage change.[782] A detailed comparison of test year operating revenue under present and proposed rates by type of charge, including minimum demand, energy by block, gross receipts, automatic adjustments, and other charge categories within each rate schedule and within each customer class of service, as well as a side-by-side comparison of the amount of revenue generated by each rate component under the current and proposed monthly fixed charges, demand charges, and per therm rates for each rate class, were also presented in a schedule.[783]

608. The Department suggested that the revenue apportionment approved for MERC should balance the goal of moving classes closer to cost with the goal of avoiding rate shock and reducing inter-class subsidies.[784] The Department initially proposed its own revenue apportionment, but later withdrew it.[785] Instead, the Department recommended that MERC's final recommended revenue apportionment be adopted, as reflected in Tables 1 and 2 and Schedule SLP-S-1 of the Surrebuttal Testimony of Susan Peirce.[786] If the Commission adopts a different revenue requirement, the Department recommended that revenues be apportioned among the classes based on the apportionment of total revenue percentages excluding gas costs reflected in SLP-S-1.[787]

609. The OAG recommended a revenue apportionment that differed slightly from what MERC recommended, on a percentage basis.[788] The OAG's revenue

[780] Ex. 37 at 6 (Lee Direct).
[781] Ex. 37 at 8 (Lee Direct).
[782] Ex. 37 at 10, ASL-1 at Schedule 3, Summary (including gas costs), and Schedule 5, Summary (not including gas costs) (Lee Direct).
[783] Ex. 37 at 10-11, ASL-1 at Schedule 3 (including gas costs), Schedule 5 (not including gas costs), and Schedule 7 (Lee Direct).
[784] Ex. 405 at 15 (Peirce Direct).
[785] Ex. 405 at 15-18 (Peirce Direct); Ex. 406 at 2-4 (Peirce Surrebuttal).
[786] Ex. 406 at 2-4 (Peirce Surrebuttal).
[787] Ex. 406 at 4 (Peirce Surrebuttal).
[788] Ex, 304 at 36, Table 4 (Nelson Direct)

apportionment sought to ease the transition for former IPL gas customers in southern Minnesota who recently became MERC customers.[789]

610. As noted above, on December 8, 2014, the Commission approved the sale of IPL's Minnesota natural gas distribution system and assets, and the transfer of its Minnesota service rights and obligations to MERC. The transfer, which occurred on May 1, 2015, affected approximately 10,600 customers in twelve communities in southeastern and south-central Minnesota including Adams, Albert Lea, Clarks Grove, Congor, Geneva, Glenville, Hollandale, Le Roy, Rose Creek, Taopi, and Wykoff. [790]

611. IPL's customers had not had a rate increase since 1996.[791]

612. To ease the rate transition for the former IPL customers, the Commission ordered that: "IPL customers affected by the transaction be transitioned to MERC's tariffs [at the time the sale closes], except that MERC maintain ... customer charges and purchase gas adjustments consistent with IPL's tariffs." The Commission further provided that "[t]his arrangement will continue until MERC's next rate case, at which time MERC will reconcile the two fuel supply systems into one."[792]

613. With this guidance in mind, the OAG's witness, Mr. Nelson, stated that he first considered the OAG's Basic System CCOSS and MERC's proposed CCOSS in developing his proposed revenue apportionment.[793] Mr. Nelson then adjusted his revenue apportionment recommendation based on a three step process to fully transition the former IPL customers onto MERC's tariffs. This process included a phase-in of customer charge increases over three rate cases. The OAG proposed that the revenue shortfall of each former IPL customer class be absorbed by both of the respective NNG and Consolidated customer classes. The OAG further suggested that the split be based off of revenues.[794]

614. The OAG's witness, Mr. Nelson, noted that in developing his proposed revenue apportionment, he attempted to collect less revenue from classes that were paying above their cost of service, and increase the revenue collected from the classes that were paying below their cost of service. He used both the OAG's and MERC's CCOSSs to determine the level of revenue for each class. He then made the adjustments discussed above to the customer charges from the former IPL customers, which lowered the revenue collected from the former IPL customers.[795]

[789] Ex. 304 at 33 (Nelson Direct),
[790] Ex. 39 at 19 (Lee Rebuttal); *In the Matter of a Request for the Approval of the Asset Purchase and Sale Agreement Between Interstate Power and Light Co. and Minnesota Energy Resources Corporation*, MPUC Docket No. G-001, G-011/PA-14-107, ORDER APPROVING SALE SUBJECT TO CONDITIONS at 1-2 (Dec. 8, 2014).
[791] *Id.* at 2.
[792] *Id.* at 3.
[793] Ex. 304 at 33 (Nelson Direct).
[794] Ex. 304 at 33-35 (Nelson Direct).
[795] Ex. 304 at 37 (Nelson Direct).

615. In Rebuttal Testimony, MERC disagreed with the OAG's proposed revenue apportionment for three reasons. First, MERC asserted that the OAG's proposed apportionment was improper because it was based on total revenues, which include the cost of gas. MERC maintained that the cost of gas should be excluded. Second, MERC disagreed with the OAG's CCOSS analysis, and its reliance on the Basic System CCOSS results. Third, MERC disagreed with the OAG's three step transition plan for customer charges, and proposed a two-step transition plan as an alternative for the Commission to consider.[796]

616. In response to MERC's comments, the OAG provided an updated revenue apportionment without the cost of gas in Surrebuttal Testimony.[797]

617. The table set forth below compares MERC's final proposed revenue apportionment to the OAG's final proposed revenue apportionment, without the cost of gas.[798]

[796] Ex. 39 at 4-6, 9, 16-17 (Lee Rebuttal).
[797] Ex. 307 at 23-24 (Nelson Surrebuttal).
[798] Ex. 307 at 24 (Nelson Surrebuttal).

MERC Customer Class	MERC Proposed	OAG Proposed Alternative
RESIDENTIAL SALES		
GS-NNG Residential Sales	51.2%	51.1%
GS-CONSOLIDATED Residential Sales	8.8%	8.7%
GS-ALBERT LEA NNG Residential Sales	2.7%	2.6%
Total	**62.7%**	**62.4%**
SC&I SALES		
GS-NNG SC&I Sales	3.5%	3.3%
GS-CONSOLIDATED SC&I Sales	1.1%	1.0%
GS-ALBERT LEA NNG SC&I Sales	0.2%	0.2%
Total	**4.8%**	**4.5%**
LC&I SALES		
GS-NNG LC&I Sales	15.1%	15.2%
GS-CONSOLIDATED LC&I Sales	4.8%	4.8%
GS-ALBERT LEA NNG LC&I Sales	0.8%	0.8%
Total	**20.6%**	**20.9%**
SMALL VOLUME SALES AND TRANSPORT		
SVI-NNG Sales	2.2%	2.2%
SVI-CONSOLIDATED Sales	0.5%	0.5%
SVI-ALBERT LEA NNG Sales	0.2%	0.2%
SVJ-NNG Sales	0.0%	0.0%
SVJ-CONSOLIDATED Sales	0.0%	0.0%
SVI-NNG Transport	0.2%	0.2%
SVI-CONSOLIDATED Transport	0.2%	0.2%
SVI-ALBERT LEA Transport	0.0%	0.0%
SVJ-NNG Transport	0.3%	0.3%
SVJ-CONSOLIDATED Transport	0.1%	0.1%
Transport for Resale	0.0%	0.0%
Total	**3.8%**	**3.8%**
SUPER LARGE AND LARGE VOLUME SALES AND TRANSPORT		
Total	**8.1%**	**8.5%**

618. The OAG recognized that the proposals are similar but maintained that its revenue apportionment should be adopted. The OAG asserted that its proposal better reflects cost causation because it relies on multiple CCOSS results (Basic System and zero-intercept).[799] In addition, the OAG asserted that proposal would result in smaller customer charge increases for the former IPL customers.[800]

619. The OAG also noted that the former IPL customers will experience a large rate increase under either party's proposal due to three factors: (1) those customers are

[799] OAG Initial Br. at 46-47 (June 29, 2016) (eDocket No. 20166-122790-01); Ex. 304 at 38-40 (Nelson Direct).
[800] Ex. 307 at 25-26 (Nelson Surrebuttal).

being merged onto MERC's NNG PGA; (2) the customer charges for IPL's former customers are lower than MERC's and will go up; and (3) MERC's overall rate increase.[801]

620. While the two revenue apportionment proposals are similar, the Administrative Law Judge concludes that MERC's proposal is the most reasonable for use in this rate case. The Administrative Law Judge reaches this conclusion for two primary reasons.

621. First, MERC's proposal is most consistent with cost causation because it is based on MERC's zero-intercept CCOSS results, whereas the OAG's proposal is based on both the Basic System CCOSS results and the zero-intercept results. As discussed above, the Administrative Law Judge concluded that the Basic System CCOSS results do not properly reflect cost causation on MERC's system.

622. Second, MERC's proposed revenue apportionment is most consistent with the Administrative Law Judge's conclusion about how best to transition former IPL customers to MERC's customer charges. While the Administrative Law Judge agrees that the former IPL customers should not be moved to MERC's existing customer charges in a single rate case because of concerns about rate shock, the Administrative Law Judge concludes that a two-step transition is more reasonable than the three-step transition proposed by the OAG. The reasons for this conclusion are discussed in detail below in the Customer Charge section.

623. Because MERC's proposed revenue apportionment best reflects these underlying decisions and the difference between the two proposals is small, the Administrative Law Judge recommends that the Commission adopt MERC's proposed revenue apportionment. The Administrative Law Judge concludes that MERC's proposed revenue apportionment, which is supported by the Department, appropriately considers both cost and non-cost factors.

D. Customer Charges - Disputed Item

624. The customer charge is a fixed monthly charge assessed without regard to usage levels. It is designed to help recover fixed customer-related costs such as the cost of meters, service lines, meter reading, and billing.[802]

625. MERC seeks to move the customer charges for certain classes closer to the customer cost estimated in its CCOSS.[803]

626. MERC's monthly customer charge is currently $9.50 for Residential service and $18 for General Service- Small Commercial and Industrial (GS-SC&I).[804] In its initial filing, MERC proposed to increase its Residential customer charge to $11 per month for

[801] Ex. 307 at 25 (Nelson Surrebuttal).
[802] 2015 CPE RATE CASE ORDER at 61.
[803] Ex. 37 at 14 (Lee Direct).
[804] Ex. 37 at 19, 46, ASL-1 at Schedule 2 (Lee Direct).

all Residential customers, and to increase its GS-SC&I customer charge to $20 per month for all Small C&I customers.[805]

627. The Department and the OAG disagreed with MERC's proposed customer charges. Both were concerned about the potential bill impacts and rate shock that former IPL customers would experience under MERC's initial proposal.[806]

628. MERC's current monthly charges and the monthly customer charges initially proposed by MERC are set out in the table below.[807]

Customer Class	MERC's CCOSS Customer Cost	Current Customer Charge Existing MERC	Current Customer Charge IPL	Proposed Customer Charge
Residential	$26.27	$9.50	$5.00	$11.00
GS – SC&I	$29.41	$18.00	$5.00	$20.00
GS-LC&I	$46.64	$45.00	$5.00	$45.00
SVI & SVJ-Sales	$110.45	$165.00	$14.00	$170.00
LVI & LVJ-Sales	$116.67	$185.00	$14.00	$190.00
SVI & SVJ - Transport	$254.64	$275.00	$210.00	$280.00
LVI&LVJ - Transport	$260.86	$295.00	$210.00	$300.00
Flex Rate	$383.56	$295.00	-	$300.00
SLVI	$478.55	$460.00	-	$470.00

629. Currently, most of MERC's residential customers pay $9.50 per month for the customer charge. However, residential and small business customers residing in the former IPL service territory, which was acquired by MERC in May 2015, pay only $5.00 per month.[808]

805 Ex. 37 at 12 (Lee Direct).
806 Ex. 405 at 19-24 (Peirce Direct); Ex. 304 at 35 (Nelson Direct).
807 Ex. 405 at 18-19 (Peirce Direct); Ex. 37, ASL-1, Schedule 3 (Lee Direct); Ex. 4, Vol. 3, Doc. No. 12, Schedule 4 (Initial Filing).
808 Ex. 405 at 18-19 (Peirce Direct); Ex. 37, ASL-1, Schedule 3 (Lee Direct); Ex. 4, Vol. 3, Doc. No. 12, Schedule 4 (Initial Filing).

630. For the former IPL customers, MERC's proposed Residential customer charge represented a 220 percent increase, from $5.00 per month to $11.00 per month.[809]

631. The significant impact of MERC's proposed $11.00 customer charge on former IPL Residential customers is due to MERC's acquisition of IPL's Minnesota gas assets in Albert Lea and the surrounding area. IPL's approximately 10,600 Minnesota natural gas customers have not had a rate increase since 1996. Consequently, the monthly gas customer charge for the former IPL customers has remained $5.00 since 1996.[810]

632. When the Commission approved the sale of IPL to MERC in December of 2014, it ordered MERC to maintain IPL-tariffed customer charges and purchased gas adjustments until MERC's next rate case.[811] However, the Commission noted:

> Minnesota IPL natural gas ratepayers have not experienced a rate increase since 1996 – approximately 18 years. While IPL's Minnesota rates have not gone up in that time, the cost of providing service to IPL's Minnesota customers has likely gone up. As a result, IPL's rates are possibly much lower than the cost of providing service, an untenable situation. IPL could not remain financially viable continuing to charge its customers rates below the cost of providing them service.[812]

633. The large increase in the former IPL customer charges proposed by MERC is also due to the fact that MERC categorizes its customers into different classes than IPL. As a result, some former IPL customers would experience significant customer charge increases simply due to re-categorization into different customer classes.[813]

634. The table below summarizes the former IPL customers newly categorized into MERC's customer classes, and identifies MERC's initial proposed customer charge for those classes.

[809] Ex. 304 at 34 (Nelson Direct); *see also* Ex. 405 at 18-19 (Peirce Direct).
[810] Ex. 37 at 39-40 (Lee Direct); *In the Matter of a Request for the Approval of the Asset Purchase and Sale Agreement Between Interstate Power and Light Company and Minnesota Energy Resources Corporation*, MPUC Docket No. G001, 011/PA-14-107, ORDER APPROVING SALE SUBJECT TO CONDITIONS at 2 (Dec. 8, 2014).
[811] *Id.* at 3.
[812] *Id.*
[813] Ex. 405 at 19 (Peirce Direct).

IPL Customers Subject to Reclassification of Customer Class[814]

IPL Customer Class	# of IPL customers at time of sale	MERC Customer class	# of customers	IPL customer charge	MERC's Initial Proposed Customer Charge
General Service	10,663	Residential	9,450	$5.00	$11.00
		Small C&I	611	$5.00	$20.00
		Large C&I	602	$5.00	$45.00
Interruptible -sales	45	SVI	39	$14.00	$170.00
		LVI	6	$14.00	$190.00
Interruptible - Transport	4	SVI-Transp.	1	$210.00	$280.00
		LVI-Transp.	3	$210.00	$300.00

635. As reflected in the above table, 611 former IPL General Service customers are classified as Small C&I customers under MERC's classification system, resulting in an increase in their customer charge from $5.00 per month to $20.00 per month under MERC's initial proposal. Similarly, an additional 602 former IPL General Service class customers are classified as Large C&I customers by MERC's initial proposal, increasing their customer charge from $5.00 per month to $45 per month in that initial proposal.[815]

636. Both the Department and the OAG recognize the need to increase the monthly charge for former IPL Residential customers in order to phase these customers into MERC's rate structure. However, both opposed MERC's proposal to increase the customer charge for all Residential customers to $11.00 per month and Small C&I to $20 per month.[816]

637. The OAG recommended maintaining the existing $9.50 customer charge for non-IPL Residential customers and moving the former IPL customers closer to that charge over the course of three rate cases. Under the OAG proposal, the former IPL Residential customer charge would be set at $6.50 in this rate case, increased to $8.00 in MERC's next rate case, and finally set at $9.50 in MERC's third rate case.[817] The OAG maintains that its three step approach is reasonable and will minimize the potential rate shock that former IPL customers may experience in response to the customer charge increases.[818]

[814] Ex. 405 at 23 (Peirce Direct) (*citing* MERC Response to DOC IR No. 314).
[815] Ex. 405 at 23 (Peirce Direct).
[816] Ex. 405 at 19 (Peirce Direct); Ex. 304 at 35 (Nelson Direct).
[817] Ex. 304 at 35 (Nelson Direct).
[818] Ex. 304 at 34 (Nelson Direct).

638. The OAG also disputed MERC's proposed customer charge increase for former IPL small C&I customers and recommended instead increasing that customer charge to only $9 per month. The OAG asserts that this $4 increase is reasonable and higher than any of the customer charge increases recently approved by the Commission.[819] Finally, the OAG recommended decreasing the Small C&I customer charge for non-IPL customers by $1.00 to $17.00 per month.[820]

639. The OAG asserted that its recommended monthly customer charges are supported by economic theory and academic research on rate design that urges adoption of customer charges that reflect only the direct customer-specific costs of adding one more customer to the distribution system – i.e., the costs of a service line, a regulator, a meter, meter reading, and account administration.[821] Depending on which specific costs were included, the OAG's witness determined the monthly "customer specific" costs for former IPL Residential customers ranges from as low as $3.28 to as high as $10.41.[822] The OAG maintained that its recommended customer charge of $6.50 for former IPL Residential customers is appropriate as it is almost exactly half-way between the high and low estimate of the customer-specific costs, as is its recommendation of a $9 customer charge for former IPL small businesses.[823] As for the non-IPL Small C&I customer charge, the OAG contended that MERC's current customer charge of $18 per month is over-collecting customer-specific costs. The OAG maintained that the customer-specific costs associated with the Small C&I class are between $5 and $13.[824] The OAG asserted that decreasing this charge by $1 will be gradual enough to correct the over-collection without causing a large financial impact on MERC.[825]

640. MERC objected to the OAG's recommendation to transition the former IPL customers over three rate cases because, in MERC's view, such an approach would result in MERC's non-IPL customers continuing to subsidize the former IPL customers over a number of years.[826]

641. MERC also asserted that OAG's analysis of "minimum" and "maximum" customer-specific costs arbitrarily excludes a number of fixed costs caused by customers on MERC's system, which traditionally have been widely accepted as costs that should be recovered through the monthly customer charge.[827] Specifically, the OAG's analysis: does not include service lines in the minimum estimate; excludes 50 percent of expense related to customer records and collection expense in both the minimum and maximum estimates; and omits other costs such as vehicles, tools, and equipment that are needed

[819] *See* OAG Initial Br. at 49-50 (June 29, 2016) (eDocket No. 20166-122790-01).
[820] Ex. 304 at 55-56 (Nelson Direct).
[821] Ex. 304 at 46-52 (Nelson Direct).
[822] Ex. 304 at 51-52, Table 7 (Nelson Direct).
[823] OAG Initial Br. at 54 (June 29, 2016) (eDocket No. 20166-122790-01).
[824] Ex. 304 at 54 (Nelson Direct).
[825] Ex. 304 at 56 (Nelson Direct).
[826] Ex. 39 at 22-24 (Lee Rebuttal).
[827] Ex. 39 at 25-26 (Lee Rebuttal); Ex. 35 at 56-60 (Hoffman Malueg Rebuttal); MERC InitialBr. at 60-63 (June 29, 2016) (eDocket No. 20166-122788-01).

in the maintenance and operation of meters and service lines, as well as office equipment that is needed regardless of system volume.[828]

642. MERC noted that a service line is required to provide service to its customers and that typically there is a one-for-one relationship of service line to customer.[829] MERC also asserted that exclusion of these cost items is inconsistent with the *NARUC Gas Manual* regarding the costs to be included for recovery via the monthly customer charge.[830] According to the NARUC Gas Manual:

> The basis for the customer charge is that there are certain fixed costs that each customer should bear whether any gas is used at all. Examples of such costs are those associated with a service line, a regulator and a meter, recurring meter reading expenses, and administrative costs of servicing the account.[831]

643. Like the OAG, the Department also recommended increasing the monthly customer charge for former IPL Residential customers from $5.00 to $6.50, and maintaining the existing $9.50 Residential customer charge for all other Residential customers. While the Department acknowledged that reducing intra-class subsidies by moving customer charges closer to customer costs is an appropriate goal, it maintained that holding customer charges for non-IPL customers steady and raising former IPL customer charges to $6.50 would narrow the differences between the two rates while lessening the potential for rate shock.[832] The Department also suggested that the Commission consider increasing the Residential customer charge slightly over a period of several years with the goal of eventually establishing the same customer charge for all Residential customers.[833] The Department maintained that this proposal balances the goal of establishing cost-based rates with the goal of achieving a moderate impact to customer bills.[834]

644. In addition, the Department recommended holding the Sales class customer charges constant for MERC's former IPL customers. The Department's witness, Ms. Peirce, noted that typically in rate cases, she recommends a small increase in the customer charge to move customer charges closer to customer costs, but in this case she recommended holding the customer charges for sales customers to their current level to narrow the customer charge rate difference between the former IPL customer and the rest of MERC's customers.[835]

645. In Rebuttal Testimony, MERC acknowledged the OAG's and Department's concerns regarding the potential for rate shock to the former IPL customers under

[828] Ex. 35 at 56-57 (Hoffman Malueg Rebuttal).
[829] Ex. 35 at 56 (Hoffman Malueg Rebuttal).
[830] MERC Initial Br. at 61 (June 29, 2016) (eDocket No. 20166-122788-01).
[831] MERC Initial Br. at 61 (June 29, 2016) (eDocket No. 20166-122788-01) (*citing* NARUC Gas Distribution Rate Design Manual at 12).
[832] Ex. 405 at 20-21 (Peirce Direct).
[833] Ex. 405 at 20-21 (Peirce Direct).
[834] Ex. 405 at 22 (Peirce Direct).
[835] Ex. 405 at 20 (Peirce Direct).

MERC's initial proposal. In response, MERC proposed to hold all existing non-IPL customers to their current customer charges and to move the former IPL customers to the midpoint between their existing customer charge and MERC's current customer charge.[836]

646. Under MERC's revised proposal, the Residential customer charge for non-IPL customers would remain at $9.50, while the charge for former IPL Residential customers would increase to $7.25 (halfway between $5.00 and $9.50). The customer charge for non-IPL Small C&I customers would remain at $18.00 per month, while the customer charge for former IPL Small C&I customers would increase to $11.50 per month. Large C&I customers would remain at $45 per month. MERC requested that the Commission order that the former IPL customers be fully transitioned to MERC customer charges in MERC's next rate case.[837]

647. In Surrebuttal Testimony, the Department did not object to MERC's current proposal, but deferred to the Commission to decide whether a smaller increase in the Residential customer charge to $6.50 for former IPL customers is warranted at this time. The Department recommended adoption of MERC's proposed customer charges for the remaining classes.[838]

648. The OAG did not agree with MERC's revised proposal and continued to recommend its initial proposal.[839]

649. The table below summarizes MERC's existing and final proposed customer charges, along with the Department's and OAG's final proposed customer charges.[840]

[836] Ex. 39 at 16-17 (Lee Rebuttal); Ex. 406 at 5 (Peirce Surrebuttal).
[837] Ex. 39 at 17 (Lee Rebuttal).
[838] Ex. 406 at 5-6 (Peirce Surrebuttal).
[839] Ex. 307 at 22 (Nelson Surrebuttal).
[840] Ex. 406 at 5 (Peirce Surrebuttal); Ex. 39 at 16-17 (Lee Rebuttal); Ex. 37, ASL-1, Schedule 1 (Lee Direct); Ex. 406 at 5 (Peirce Direct); Ex. 304 at 55 (Nelson Direct); OAG's Initial Br. at 49-50 (June 29, 2016) (eDocket No. 20166-122790-01).

Current and Proposed Customer Charges

Customer Class	MERC Current	MERC Proposed	DOC Proposal	OAG Proposal
Residential:				
Existing MERC	$9.50	$9.50	$9.50	$9.50
Former IPL	$5.00	$7.25	$7.25/$6.50	$6.50
GS – SC&I:				
Existing MERC	$18.00	$18.00	$18.00	$17.00
Former IPL	$5.00	$11.50	$11.50	$9.00
GS-LC&I:				
Existing MERC	$45.00	$45.00	$45.00	
Former IPL	$5.00	$25.00	$25.00	
SVI & SVJ-Sales:				
Existing MERC	$165.00	$165.00	$165.00	
Former IPL	$14.00	$89.50	$89.50	
LVI & LVJ-Sales:				
Existing MERC	$185.00	$185.00	$185.00	
Former IPL	$14.00	$99.50	$99.50	
SVI & SVJ – Transport				
Existing MERC	$275.00	$280.00	$280.00	
Former IPL	$210.00	$280.00	$280.00	
LVI&LVJ – Transport				
Existing MERC	$295.00	$300.00	$300.00	
Former IPL	$210.00	$300.00	$300.00	
Flex Rate	$295.00	$300.00	$300.00	
SLVI	$460.00	$470.00	$470.00	

650. As the chart above shows, MERC's revised proposal is the same as the Department's proposal, except that the Department did not make a final recommendation on the Residential customer charge for former IPL customers. The OAG's proposal, however, calls for lower customer charges for former IPL customers in the Residential Class and for all customers in the Small C&I class.

651. The Department also recommended that MERC be directed to provide information to the former IPL customers on its Conservation Improvement Program (CIP) offerings, Low Income Heating Assistance Program (LIHEAP) availability, and Gas Affordability Program (GAP), and requested that MERC provide additional information about how it intends to inform customers of these program offerings. [841]

[841] Ex. 405 at 24 (Peirce Direct).

652. In its response, MERC stated that it has and will continue to provide its former IPL customers the same bill inserts and direct mailings regarding its CIP, GAP and Energy Assistance programs that it provides to its other MERC customers.[842]

653. In considering which rate design to recommend, the Administrative Law Judge recognizes that moving classes closer to cost is consistent with the rate design principle that rates should promote efficient use of resources and minimize inter-class subsidies.[843] Minimizing inter-class subsidies is perceived to be "fair" to all ratepayers and it gives customers accurate information (or "price signals") about the cost of energy.

654. However, when setting rates other concerns need to be balanced including promoting intra-class equity and minimizing rate shock that certain customers may experience in response to a large, sudden change in the fixed monthly charge.[844]

655. The Administrative Law Judge concludes that MERC's proposal to hold all existing non-IPL customers to their current customer charges and to move the former IPL customers to the midpoint between their existing customer charge and MERC's current customer charge is reasonable and appropriately balances concerns about rate shock to the former IPL customers with the other rate design principles.

656. The Administrative Law Judge finds that MERC's proposal to increase the Residential customer charge for former IPL customers to $7.25 per month to begin the process of moving the IPL customers closer to the cost of service and reduce intra-class subsidies is appropriate and recommends the Commission adopt it. Although a $2.25 increase in the monthly charge will be significant for the former IPL customers, these customers have not had a rate increase in 20 years (since 1996) and are currently being charged rates well below the cost of providing them service.[845] Moreover, a $7.25 per month customer charge is below both Xcel's $9.00 per month Residential gas customer charge,[846] and CenterPoint's $9.50 per month Residential customer charge.[847]

657. MERC's request to move the former IPL customers to the midpoint between their existing customer charge and MERC's current Residential customer charges is reasonable. The proposed $7.25 rate for the former IPL Residential customers will reduce further subsidization of costs by MERC's other customers and provide a sufficient economic price signal to encourage energy conservation, while still being small enough to minimize the potential for rate shock.

[842] Ex. 39 at 19-21 (Lee Rebuttal).
[843] 2013 MERC RATE CASE ORDER at 52.
[844] 2013 MERC RATE CASE ORDER at 51-52.
[845] Ex. 35 at 52-55, JCHM-R3 (Hoffman Malueg Rebuttal).
[846] *See In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, for Authority to Increase Rates for Natural Gas Service in Minnesota*, MPUC Docket No. G-002/GR-09-1153, FINDINGS OF FACT, CONCLUSIONS AND ORDER at 35 (Dec. 6, 2010).
[847] *See In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota*, MPUC Docket G-008/GR-15-424, FINDINGS OF FACT, CONCLUSIONS AND ORDER at 64-65 (June 3, 2016).

658. The Administrative Law Judge does not recommend adopting the OAG's proposal to transition the former IPL customers to the MERC customer charge over the course of three rate cases. The OAG's proposal would result in MERC's non-IPL customers continuing to subsidize MERC's IPL customers over a number of years. Such a long transition would result in unreasonably preferential rates for the former IPL customers who receive the same service and are in the same class of service as MERC's other customers. The Administrative Law Judge recommends instead that the Commission order that the former IPL customers be fully transitioned to MERC customer charges in the Company's next rate case.

659. In summary, the Administrative Law Judge finds that MERC's proposed customer charges as recommended in its Rebuttal Testimony best balance the interests relevant to establishing just and reasonable rates and should be approved.

X. Other Issues - Disputed

A. Decoupling

660. Decoupling is a "regulatory tool designed to separate a utility's revenue from changes in energy sales."[848] In general, a revenue decoupling mechanism (RDM) is a revenue true-up that revises energy rates to recover differences between actual and forecasted base class revenue responsibility.[849] The true-up decreases or increases energy rates charged to customers if their collective usage during a given time period deviates from a set base amount.[850]

661. In reviewing decoupling programs, the Commission considers whether the decoupling mechanism: (1) will reduce a utility's disincentive to promote energy efficiency, (2) is consistent with statutory energy savings goals, and (3) will adversely affect utility ratepayers.[851]

662. MERC's current RDM is a full decoupling[852] pilot program approved by the Commission as part of the 2010 MERC rate case.[853] The program applies to the Residential and Small C&I customer classes only, and contains a symmetrical 10 percent cap on revenues generated through application of the RDM.[854]

[848] Minn. Stat. § 216B.2412, subd. 1 (2016).
[849] Ex. 402 at 2 (Davis Direct).
[850] Ex. 402 at 2 (Davis Direct).
[851] Minn. Stat. § 216B.2412, subd. 2 (2016).
[852] A full decoupling mechanism is one where the true-up amount is based on differences between forecasted revenue and actual sales that occur regardless of the reason, including weather deviations. Ex. 402 at 2 (Davis Direct).
[853] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. To Increase Rates for Natural Gas Serv. in Minn.*, MPUC G-007, 011/GR-10-977, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 12-15 (July 13, 2012) (2010 MERC ORDER).
[854] 2010 MERC ORDER at 12.

663. The pilot program became effective on January 1, 2013, and was scheduled to end on December 31, 2015.[855] On August 11, 2015, the Commission indefinitely extended the time period for MERC's decoupling pilot program.[856]

664. In this case, MERC seeks extension of the current decoupling pilot program for another three years with the symmetrical cap currently in place, but does not support including additional customer classes in the program.[857] MERC argued that the structure of the rate classes and rate design makes application of the current RDM to large industrial classes impracticable.[858] With regard to the current symmetrical cap, MERC is willing to remove the cap entirely, but claims implementation of an asymmetrical cap would be an undue burden.[859] According to MERC, it would rather terminate the decoupling program entirely rather than have an asymmetrical cap imposed.[860]

665. At the outset of this proceeding, the Department asked MERC to provide an update on its 2015 CIP achievements in order to analyze the impact of the decoupling pilot program on energy savings.[861] MERC provided the requested update regarding its 2015 CIP achievements.[862] According to the Department's analysis of MERC's 2010-2015 CIP data, MERC has demonstrated overall energy savings during the time the decoupling pilot program has been in place. The Department noted, however, that MERC's Residential energy savings have declined more than 15 percent since the decoupling program was first instituted in 2013.[863]

666. The Department agreed with MERC's request to have its current decoupling pilot program extended for another three years.[864] The Department did not support extending the decoupling program to additional customer classes at this time because the record does not show that MERC has a throughput incentive[865] to increase sales to its larger customer classes.[866] With regard to the cap, the Department initially recommended application of an asymmetrical cap to MERC's decoupling program to ensure adequate ratepayer protection.[867] However, upon review of information acquired during discovery, the Department concluded it is reasonable for MERC's decoupling

[855] 2010 MERC ORDER at 12-15.
[856] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. To Increase Rates for Natural Gas Serv. in Minn.*, MPUC G-007, 011/GR-10-977, ORDER at 1 (Aug. 11, 2015).
[857] Ex. 41 at 74 (DeMerritt Direct).
[858] Ex. 41 at 78 (DeMerritt Direct).
[859] Ex. 41 at 79-80 (DeMerritt Direct).
[860] Ex. 41 at 73 (DeMerritt Direct).
[861] Ex. 402 at 16 (Davis Direct).
[862] Ex. 39 at 32 (Lee Rebuttal).
[863] Ex. 403 at 3-5 (Davis Surrebuttal).
[864] Ex. 403 at 14 (Davis Surrebuttal).
[865] Because of the high fixed costs associated with the natural gas and electric utility industries, a utility's marginal revenue often exceeds its short-run marginal costs, giving a utility an incentive to increase sales. This phenomenon is referred to as the "throughput incentive." Ex. 402 at 6 (Davis Direct).
[866] Ex. 403 at 14 (Davis Surrebuttal).
[867] Ex. 402 at 16 (Davis Direct).

program to maintain a symmetrical cap for now because an asymmetrical cap could undermine MERC's disincentive to encourage energy savings.[868]

667. While the Department supported extending MERC's decoupling program in its current form, the Department did recommend additional reporting by MERC regarding these issues. The Department suggested that MERC be required, in its next rate case, to demonstrate why extending decoupling to all customer classes with more than 50 customers is not reasonable, and also address evidence showing energy savings for Residential customers has decreased since inception of the decoupling pilot program.[869]

668. MERC agreed with the Department's recommendation for future reporting requirements.[870]

669. The OAG did not support continuation of MERC's decoupling program in its current form. The OAG disagreed with the Department's assessment of MERC's decoupling program. The OAG maintained that MERC did not present sufficient quantitative analysis to demonstrate decoupling could be detrimental to large industrial customer classes with a small number of customers. The OAG also asserted that the Department's throughput analysis was unreliable. In addition, OAG maintained that MERC has not demonstrated that its decoupling program will benefit ratepayers.[871]

670. As a result, the OAG recommended that the following changes be applied to MERC's decoupling pilot program if extended: (1) all customer classes with more than 50 customers should be decoupled; (2) MERC must achieve 1.2 percent energy savings through its conservation improvement programs to administer any surcharges via the decoupling program; and (3) MERC should not be allowed to increase the Residential or Small Business classes' customer charges.[872]

671. MERC disagreed with the OAG's position regarding its decoupling program. First, MERC claimed extension of decoupling to additional customer classes would have unintended negative consequences outweighing any possible benefits.[873] MERC pointed out that when the Commission originally approved MERC's decoupling pilot program, the Commission determined that MERC lacks the same throughput incentive for large customer classes as small customer classes.[874] Second, MERC asserted allowing surcharges only upon achievement of a 1.2 percent energy savings threshold is not reasonable because many variables unrelated to decoupling affect MERC's energy savings.[875] MERC pointed out that the Commission has previously refused to make decoupling contingent on achieving a specific energy savings result.[876] Third, MERC asserted the proposed customer charges for the Residential and Small C&I classes do

[868] Ex. 403 at 8-9 (David Surrebuttal).
[869] Ex. 403 at 14-15 (Davis Surrebuttal).
[870] Tr. Vol. 1 at 85 (Lee).
[871] Ex. 306 at 1-13 (Nelson Rebuttal).
[872] Ex. 306 at 12-13 (Nelson Rebuttal).
[873] Ex. 40 at 8-9 (Lee Surrebuttal).
[874] 2010 MERC ORDER at 14.
[875] Ex. 40 at 17-18 (Lee Surrebuttal).
[876] 2010 MERC ORDER at 13-14.

not fully cover the customer-related fixed costs of providing services, which MERC incurs regardless of whether the customer uses any gas.[877] According to MERC, setting customer charges below the fixed cost of providing service gives inaccurate price signals to customers and increases intra-class subsidies.[878]

672. The Administrative Law Judge concludes that continuation of MERC's current decoupling pilot program for another three years in its current form is reasonable and appropriate. MERC's current decoupling pilot program has been approved and indefinitely extended by the Commission, and evidence presented during this proceeding has not proven an urgent need to change or eliminate the program.

673. With regard to the OAG's proposal in particular, the Administrative Law Judge already has recommended that MERC's customer charges remain the same for all MERC customers at least until the next rate case, except for the former IPL customers. In terms of the other two aspects of the OAG's proposal (extending decoupling to other classes and tying decoupling to meeting an energy savings goal), the Administrative Law Judge recognizes that the Commission has already denied similar requests in prior decisions.

674. However, the Administrative Law Judge agrees with the Department and the OAG that MERC should be required in its next rate case to demonstrate why extending decoupling to all customer classes is not reasonable. The Administrative Law Judge also agrees with the Department that MERC should be required in its next rate case to address evidence showing Residential energy savings has decreased since inception of the decoupling pilot program.

B. Notice Requirements for Switching to and from Transportation Service

675. MERC's existing tariff includes notice requirements customers who seek to switch to sales service from transportation service and vice versa. Under the 3rd Revised Sheet No. 6.01 of MERC's tariff:

> Customers may transfer to Transportation Service for the period November 1 through October 31 after giving the Company ninety days advance notice prior to November 1. A transportation customer must maintain transportation service for the entire November through October period. A transportation customer may not return to sales service until the next November 1st and must notify the Company in writing at least ninety days prior to the transfer. A customer may only transfer to firm sales service if Company is able to arrange adequate firm gas entitlements to meet the needs imposed on its system by the customer, without jeopardizing system reliability or increasing costs for its customers.[879]

[877] Ex. 40 at 19 (Lee Surrebuttal).
[878] Ex. 40 at 19 (Lee Surrebuttal).
[879] Ex. 200 at 10-11 (Sorenson Direct) (quoting MERC's 3rd Revised Sheet No. 6.01).

676. Constellation maintains that the current tariff is unduly restrictive and more flexibility is needed for customers when their circumstances change unexpectedly.[880]

677. Constellation provided an example of a transportation customer whose business experienced financial hardship. The customer's gas consumption dropped dramatically as it ceased operations, but it needed to maintain a minimal amount of heat at its building while it was trying to sell the facility. At that point, the lower volumes no longer warranted gas transportation service and the customer wanted to switch to MERC's sales service. However, the customer made the decision in late summer. Constellation was willing to release the customer, but MERC would not accept the customer as a sales customer at that point because the August 1 deadline for providing the 90-day notice had already passed.[881] As a result, the customer had to remain on transportation service, paying the additional costs of that service, for more than a year.[882]

678. To address situations like this, Constellation proposed that MERC modify its tariff language to provide more flexibility in the notice required to switch services. More specifically, Constellation proposed that MERC add language similar to that found in the tariff of MERC's affiliate Wisconsin Public Service Corporation (WPS), which provides that the existing notice requirements in the tariff may be waived:

> [in the Company's sole discretion, if the Company has adequate gas supply and interstate pipeline capacity to serve the customer, and the Company anticipates no significant detriment to existing system sales customers. If the Company waives the notice requirement, the Company may require the customer to pay an exit fee to recover the costs related to a switch to or from service under this rate schedule. This exit fee may include, but is not limited to, any above market gas commodity costs, any interstate pipeline transportation and/or storage costs, and any other demand costs.[883]

679. Constellation maintained that this or similar language would give MERC the ability, at its sole discretion, to waive the notice requirements without harming MERC or its customers.[884]

680. Constellation also proposed that MERC's tariff be modified: to allow 30-days' notice, rather than 90-days' notice, when notice is provided between April 1 and July 31 (outside of the heating season); to allow the move from sales service to transportation service on the first day of any month between April 1 and July 31; and to provide that the one-year restriction from switching be a rolling one-year period rather than the November 1 through October 31 time frame currently included in the tariff.[885]

[880] Ex. 202 (Sorenson Testimony Summary).
[881] Ex. 200 at 11 (Sorenson Direct); Ex. 201 at 8 (Sorenson Surrebuttal).
[882] Ex. 201 at 8 (Sorenson Surrebuttal).
[883] Ex. 200 at 12 (Sorenson Direct).
[884] Ex. 200 at 12 (Sorenson Direct).
[885] Ex. 200 at 12 (Sorenson Direct).

681. MERC opposed Constellation's proposed notice changes and recommended the changes be rejected by the Commission. According to MERC, the 90-day notice requirement is necessary to ensure MERC has adequate time to make account changes, install and test telemetry equipment, perform gas meter modifications, make billing system changes, and allow for changes to demand entitlements.[886]

682. In addition, MERC emphasized that it is required to submit an annual demand entitlement filing every year on November 1, identifying the amount of firm pipeline capacity to be purchased for the upcoming November through October time period.[887]

683. According to MERC, "shortening the notification period or allowing unplanned switches from the Firm rate schedule to the Transportation Gas schedule outside of the required November through October time period could cause harm, in the form of stranded pipeline capacity costs, to those customers remaining on the Firm rate schedule. Conversely, shortening the notification period or allowing unplanned switches from the Transportation Gas rate schedule to the Firm rate schedule could cause harm by decreasing the amount of winter capacity available to customers on the firm rate schedule, increasing the probability of gas supply interruptions."[888]

684. In addition, MERC stated that the WPS tariff includes the waiver language because WPS normally requires 245-days' notice for a customer to switch to or from systems sales service. In MERC's view, because its notice period is much shorter (90 days), the waiver language proposed by Constellation is unnecessary.[889]

685. In Surrebuttal Testimony, Constellation reiterated that its waiver proposal is intended to apply only if there is no detriment to sales customers and any waiver would be at the sole discretion of MERC. Constellation also asserted that MERC mistakenly interpreted its waiver proposal to prohibit MERC from continuing to require 90-days' notice. In addition, Constellation clarified that while it proposed using the WPS tariff language, it is willing to entertain alternative tariff language.[890]

686. The Administrative Law Judge concludes the record supports Constellation's proposal to allow MERC the discretion to grant a waiver of the notice provisions to address unique circumstances facing a customer, where doing so would have no detriment to existing sales customers. Constellation has provided evidence of a situation where a waiver of the August 1 deadline would have been justified for a customer facing unforeseen financial difficulties. To be reasonable, however, the waiver must only be permitted where there is no detriment to existing system sales customers. The WPS tariff language proposed by Constellation is insufficient in this regard because it allows a waiver where the company "anticipates no **significant** detriment to existing system sales

[886] Ex. 39 at 47 (Lee Rebuttal).
[887] Ex. 39 at 48 (Lee Rebuttal).
[888] Ex. 39 at 48 (Lee Rebuttal).
[889] Ex. 39 at 48-49 (Lee Rebuttal).
[890] Ex. 201 at 7 (Sorenson Surrebuttal).

customers."[891] Thus, the WPS language allows some detriment, just not a "significant detriment." In addition, in the view of the Administrative Law Judge, the WPS language is also insufficient because it is not limited to customers facing unforeseen circumstances. The waiver should be limited to customers facing unforeseen circumstances so that it is not used by customers who could have requested a waiver prior to the normal August 1 deadline. If the Commission agrees, the Commission should require the Company either to revise the WPS language or propose new language consistent with this recommendation as part of a compliance filing.

687. With regard to Constellation's other proposed revisions to the existing notice requirements set forth in paragraph 680 above, the Administrative Law Judge agrees with MERC that Constellation's proposals are not supported by the record. MERC has shown a 90-day notice period is generally necessary. MERC has also provided evidence to support the November 1 to October 30 service requirement.[892] Moreover, if waiver language is added to the tariff, it is unnecessary to further revise the existing language to address these concerns because customers facing unforeseen circumstances will be able to request a waiver.

C. Non-Telemetered Small Volume Transportation Service

688. Prior to its 2008 rate case, MERC allowed Small Volume transportation service customers to pay a volumetric balancing fee in lieu of installing the telemetry equipment otherwise required by its tariff.[893]

689. In MERC's 2008 rate case, the Company proposed to stop offering small volume balancing service to its transportation customers and to instead require these customers to install telemetry equipment.[894] Telemetry equipment allows MERC and transportation customers to more accurately and efficiently monitor a customer's natural gas usage and the sufficiency of the customer's purchased supply.[895]

690. In its 2008 Order, the Commission approved the request. The Commission explained its decision as follows:

> The cost of telemetry equipment is not exorbitant and does not, even in the near term, exceed the cost of the balancing services Small Volume customers are currently purchasing; the one-time cost of telemetry equipment is comparable to the recurring, annual cost of balancing services. Second, the Company offers favorable financing plans for the purchase of telemetry equipment, which the Commission will require it to continue. Further, the precision that telemetry offers will enable both

[891] Ex. 200 at 12, SS-6 (Sorenson Direct) (emphasis added).
[892] *See* Ex. 39 at 47-48 (Lee Rebuttal).
[893] Ex. 200 at 5 (Sorenson Direct).
[894] *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, MPUC Docket No. G-007-08-835, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 17 (June 29, 2009) (2008 MERC ORDER).
[895] 2008 MERC ORDER at 17.

customers and Company to manage their natural gas supplies more efficiently and cost-effectively.[896]

691. According to Constellation, the Commission's decision in the 2008 rate case had the unintended consequence making small volume transportation service unaffordable for many customers.[897] In support of its position, Constellation noted that it provided natural gas commodity and related services to approximately 138 Small Volume customers before telemetry was required. After telemetry was required, approximately 100 of Constellation's customers stopped taking service. Constellation asserted that these customers no longer found it feasible to purchase their natural gas commodity competitively due to the additional costs and requirements associated with telemetering.[898]

692. Constellation pointed out that MERC charges to install telemetry equipment. The cost ranges between $905 and $2,250, with an average cost of approximately $1,100 per installation. The cost varies based upon the equipment and time associated with its installation.[899]

693. Constellation requested that the Company be required to submit a proposed tariff for a Small Volume non-telemetered program in its next rate case or within three years following the final order in this proceeding, whichever is earlier. Constellation also requested that the Commission require the Company to work collaboratively with interested third party suppliers and customers in developing the proposal.[900] Constellation believes that with a properly structured tariff and appropriate monthly balancing fee, non-transportation tariff ratepayers would not be affected by lack of telemetry requirement for Small Volume customers.[901]

694. Constellation noted that several other natural gas local distribution companies, including former MERC affiliates in Iowa and Nebraska, provide non-telemetered transportation options for commercial customers.[902] Constellation highlighted those in Iowa and South Dakota because "these non-telemetered services operate at utilities that are located behind the same natural gas pipelines as those that serve MERC, specifically Northern Natural Gas and Northern Border Pipeline Co."[903]

695. MERC opposed Constellation's request for a non-telemetered Small Volume transportation program because it would require significant changes to MERC's gas supply, transportation, and billing areas. MERC also claimed that such a program would "undermine the benefits from MERC's telemetry program."[904]

[896] *Id.* at 17-18.
[897] Ex. 200 at 5-6 (Sorenson Direct); Ex. 201 at 3 (Sorenson Surrebuttal).
[898] Ex. 200 at 5-6 (Sorenson Direct).
[899] Ex. 200 at 6 (Sorenson Direct).
[900] Ex. 200 at 9 (Sorenson Direct).
[901] Ex. 200 at 6 (Sorenson Direct).
[902] Ex. 200 at 6 (Sorenson Direct).
[903] Ex. 200 at 7 (Sorenson Direct).
[904] Ex. 39 at 43 (Lee Rebuttal).

696. MERC currently requires all interruptible customers to install telemetry equipment. In practice, use of telemetry has improved MERC's ability to manage natural gas supply more efficiently and cost-effectively.[905] In its pending Demand Entitlement docket, Commission staff noted that staff believes "the daily interruptible data availability enhanced MERC's ability to calculate its [design day] requirements, which led to the capacity reduction. The annual reduction provides MERC ratepayers with approximate savings of $1.1 million."[906]

697. In MERC's view, providing a Small Volume non-telemetered gas transportation program would undermine these benefits and would result in increased costs.[907] For these reasons, MERC opposed Constellation's proposal. If, however, the Commission believes a further evaluation of such a program is desirable, MERC suggested that such a program be considered in a separate docket, apart from a rate case.[908]

698. Based on a review of the record, the Administrative Law Judge concludes that Constellation has not provided sufficient evidence to support its proposal for a non-telemetered Small Volume transportation program. While Constellation claims that the telemetry requirement has made transportation service unaffordable for many Small Volume customers, Constellation's claim is based solely on its loss of commodity customers after the telemetry requirement was adopted. There is no specific evidence in the record from any of these customers to show that the cost of the telemetry equipment, which averages $1,100, made the transportation service unaffordable. While such cost evidence of may exist, Constellation has not offered any such evidence into the record. Similarly, Constellation's reliance on programs from other states, without more, does not show that such programs are more reasonable than MERC's requirement of telemetry for all interruptible transportation customers. In contrast, the record shows that MERC's telemetry program has improved MERC's ability to manage its natural gas supply more efficiently and cost-effectively, resulting in approximate savings of $1.1 million for MERC's customers.[909]

699. For these reasons, the Administrative Law Judge recommends that the Commission take no action on Constellation's proposal at this time. If Constellation is able to develop additional evidence to support its proposal, it could file a separate petition with the Commission or include its proposal in MERC's next rate case.

D. Transportation Imbalance Process

[905] Ex. 39 at 44 (Lee Rebuttal).
[906] *In the Matter of Petitioners by Minnesota Energy Resources Corporation (MERC-Consolidated, MERC-NNG- and MERC-Albert Lea) for Approval of Changes in Contract Demand Entitlements for the 2015-2016 Heating Season Supply Plan Effective November 1, 2015*, MPUC Docket Nos. G011/M-15-722, G011/M-15-723, G011/M-15-724, MINNESOTA PUBLIC UTILITIES COMMISSION STAFF BRIEFING PAPERS at 8-9 (April 5, 2016).
[907] Ex. 39 at 44 (Lee Rebuttal).
[908] Ex. 39 at 44-45 (Lee Rebuttal).
[909] Ex. 201 at 4-5 (Sorenson Rebuttal).

700. On January 5-7, and January 25-29, 2014, MERC curtailed all gas service to Interruptible and Joint Service transportation customers to ensure continued delivery of natural gas to firm customers.[910]

701. During this time period, the market value of the gas ranged from a low of \$6.750 MMBtu to a high of \$53.305 MMBtu.[911]

702. MERC used its current imbalance process to return the volume of gas through an infield transfer on March 13, 2014, when the market price of gas was \$5.140 per MMBtu.[912]

703. MERC's current imbalance process addresses both situations where a transportation customer overnominates and does not utilize all of the gas, as well as situation where a customer undernominates and utilizes more gas than is delivered. MERC's current imbalance process largely mirrors the NNG imbalance calculation method.[913]

704. Constellation has proposed new tariff language that would apply when curtailments are made on a Critical Day or when an Operational Flow Order (OFO) is declared, specifying a new method for compensating transportation customers in these circumstances.[914] Under Constellation's proposal, the price that would be paid under such circumstances would be equal to the price of gas at the time MERC provided notice of the Critical Day as reported in Platt's Gas Daily as "Midpoint for Chicago Citygates" under the Citygates section of Platts *Gas Daily* plus 10%.[915]

705. Constellation also proposed that MERC be required to post on its website information regarding each Critical Day or OFO called, including the date of the event, the duration and geographic boundaries of the event, and an explanation of the underlying cause or causes of the event.[916]

706. MERC did not agree with either recommendation.[917]

707. MERC disagreed with the recommendation that it revise its current imbalance process. First, MERC contended that its existing monthly imbalance process is designed to fairly balance situations of over-nomination or under-nomination and that its existing tariff provides a number of reasonable alternatives for transportation customers in the event a curtailment is called.[918] For example, transportation customers may elect either an imbalance cash out or infield transfer to storage for monthly balances. In addition, transportation customers may make an intraday nomination of gas after a

[910] Ex. 200 at 13 (Sorenson Direct); Ex. 39 at 50 (Lee Rebuttal).
[911] Ex. 201 at 11 (Sorenson Surrebuttal)
[912] Ex. 201 at 11 (Sorenson Surrebuttal).
[913] Tr. Vol. 1 at 156 (Sorenson).
[914] Ex. 202 (Sorenson Opening Statement).
[915] Ex. 202 (Sorenson Opening Statement).
[916] Ex. 200 at 15-16 (Sorenson Direct).
[917] Ex. 39 at 50-51 (Lee Rebuttal).
[918] Ex. 39 at 50 (Lee Rebuttal).

curtailment is called, and customers who are called upon to curtail may elect to continue to utilize natural gas, subject to curtailment penalties.[919]

708. Second, MERC maintained that Constellation's suggested tariff revisions would allow marketers, such as Constellation, to effectively game the imbalance process in order to achieve a windfall for over-and-under designated gas. MERC asserted that its methodology for calculating the monthly cashout for its customers who receive service on the NNG pipeline largely mirrors NNG's cashout calculation methodology in order to avoid opportunities for parties to try to manipulate the imbalance process.[920]

709. MERC also disagreed with the recommendation to post information regarding each Critical Day or OFO called on the Company's website because MERC notifies affected customers of curtailment start and end times directly. MERC asserted that this process is sufficient to ensure customers are informed of curtailment events and that publishing additional information on the Company's website could lead to potential customer confusion.[921]

710. The Administrative Law Judge finds that the Constellation's proposed changes to MERC's tariff are unnecessary and that MERC's existing imbalance process is reasonable as MERC's existing tariff provides a number of alternatives for transportation customers in the event a curtailment is called. The Administrative Law Judge also agrees with MERC that Constellation's proposal that MERC publish information on its website regarding each Critical Day or OFO called is unnecessary given that affected customers are notified directly.

XI. Other Issues – Resolved

A. Small Volume Firm Transportation Service

711. Constellation initially recommended that MERC reevaluate its class of service options for transportation service and investigate the feasibility and market propensity for a small volume firm transportation service option.[922]

712. MERC disagreed with Constellation's recommendation.[923]

713. In response to discovery, MERC stated that its joint service tariffs allow a transportation customer to have 100 percent firm delivery of its third party gas supply from the city gate to the customer facility.[924]

919 Tr. Vol. 1 at 85 (Sorenson).
920 MERC's Initial Br. at 84-85 (June 29, 2016) (eDocket No. 20166-12788-01).
921 Ex. 39 at 51 (Lee Rebuttal).
922 Ex. 200 at10 (Sorenson Direct).
923 Ex. 39 at 45-46 (Lee Rebuttal).
924 Ex. 201, Schedule SS-2 (Sorenson Surrebuttal).

714. Constellation agreed that MERC's Small and Large Volume Joint Service tariff meets small customer needs for a firm transportation service and determined that the issue was no longer contested.[925]

715. No other party offered testimony on this issue.

716. The Administrative Law Judge finds concludes that no Commission action is needed on this issue.

B. Joint Service Affidavit for Firm Transportation Customers

717. Constellation recommended the elimination, or at a minimum modification, of MERC's Joint Service Affidavit for Firm Transportation Customers. Constellation expressed concern that MERC currently requires both the marketer and the end-use customer to sign the form simultaneously before a notary, a time-consuming and costly task.[926]

718. MERC did not agree to eliminate the Joint Service Affidavit but did agree to modify the document such that the need for notarization is eliminated, and simultaneous customer and marketer signatures are no longer required, allowing for signatures to be made at separate times and locations.[927]

719. Constellation agreed with MERC's proposal to modify the Joint Service Affidavit.[928]

720. No other party offered testimony on this issue.

721. The Administrative Law Judge finds that MERC's proposed modification to its Joint Service Affidavit for Firm Transportation Customers as described in Rebuttal Testimony is reasonable and should be adopted.

C. Cost of Gas

722. MERC submitted a Petition for approval of a new Base Cost of Gas for interim rates, concurrently with its Initial Filing in this docket, using NYMEX data from May 15, 2015, as described in MERC's base cost of gas filing in Docket No. G011/MR-15-748.[929]

723. The Commission issued an Order Setting New Base Cost of Gas and Requiring Further Filings on November 30, 2015, approving an adjusted interim base cost of gas purchased gas adjustment and requiring MERC to recalculate and restate its purchased gas adjustment factors and resubmit its interim base cost of gas. The Commission's order further required that MERC provide updated information about the

[925] Ex. 201 at 6-7 (Sorenson Surrebuttal).
[926] Ex. 200 at 17-18 (Sorenson Direct).
[927] Ex. 39 at 53 (Lee Rebuttal).
[928] Ex. 201 at 18 (Sorenson Surrebuttal).
[929] Ex. 41 at 16 (DeMerritt Direct).

commodity base cost of gas during the course of the general rate case proceeding and work with the Department and Commission staff to determine the timing of its update.[930]

724. In Direct Testimony, the Department recommended that MERC be required to reduce its base cost of gas and revenues by $8,477,852, for a net effect on the revenue requirement of zero.[931]

725. MERC filed an update to the commodity cost of gas based on NYMEX prices as of March 15, 2016 on April 12, 2016, in accordance with the agreement of the parties.[932]

726. MERC agreed that an adjustment is appropriate to reflect the updated cost of gas and revenues and provided that the updated cost of gas as submitted on April 12, 2016, in this docket and Docket No. G011/MR-15-748, was the appropriate cost of gas to be used.[933] The update reflected a reduction to the cost of gas and revenues of $43,522,851 relative to MERC's original filing.[934]

727. The Department agreed with MERC's proposed adjustment.[935]

728. No other party offered testimony on this issue.

729. The Administrative Law Judge finds that the updated cost of gas filed on April 12, 2016 in this docket[936] should be used in the test year, decreasing PGA revenue and expense by $43,522,851 from MERC's originally filed figures.

D. Test Year

730. Minn. Stat. § 216B.16, subd. 3(a), requires interim rates to start within 60 days of the initial rate case filing. MERC's test year begins January 1, 2016. MERC filed its rate case on September 30, 2015 (93 days before January 1) and waived its right under the statute to have interim rates in effect not later than 60 days after the initial filing.[937]

731. In its Notice of and Order for Hearing issued November 30, 2015, the Commission ordered that the parties specifically and thoroughly address the question of whether the test year in this case and in future MERC rate cases should be so far removed

930 ORDER SETTING NEW BASE COST OF GAS AND REQUIRING FURTHER FILINGS at 4 (Nov. 30, 2015) (eDocket No. 201511-116012-02); *see also In the Matter of the Petition of Minn. Energy Res. Corp. for Approval of a New Base Cost of Gas to Coincide with Implementation of Interim Rates*, MPUC Docket No. G011/M-15-748, ORDER SETTING NEW BASE COST OF GAS AND REQUIRING FURTHER FILINGS at 4 (Nov. 30, 2015).
931 Ex. 416 at 40 (St. Pierre Direct).
932 COMPLIANCE FILING -- BASE COST OF GAS UPDATE (Apr. 12, 2016) (eDocket No. 20164-119985-02); *see also In the Matter of the Petition of Minn. Energy Res. Corp. for Approval of a New Base Cost of Gas*, MPUC Docket No. G011/M-15-748, COMPLIANCE FILING -- BASE COST OF GAS UPDATE (Apr. 12, 2016).
933 Ex. 45 at 20 (DeMerritt Rebuttal).
934 Ex. 45 at 20 (DeMerritt Rebuttal).
935 Ex. 401 at 11-12 (Shah Surrebuttal).
936 BASE COST OF GAS UPDATE (Apr. 12, 2016) (eDocket No. 20164-119985-02).
937 Ex. 2, Vol. 1, Interim Rate Petition at 2 (Application).

from the most recent fiscal year and whether the test year should be allowed to start more than 60 days after the filing date.[938]

732. The Department concluded that the 2016 test year is not unreasonably far removed from the most recent calendar year 2014 and did not have a concern with utilities filing more than 60 days in advance of interim rates.[939] The Department, however, cautioned against allowing more than MERC's present filing of 93 days in advance of interim rates.[940]

733. MERC agrees that the 2016 test year is not unreasonably far removed from the most recent calendar year. MERC is not overly concerned with filing a future rate case more than 93 days in advance of interim rates, but requested a few days' leeway in the event September 30 falls on a weekend, such that it becomes necessary to file on the prior Friday and therefore, slightly earlier.[941]

734. The Department agreed with MERC's request.[942]

735. No other party offered testimony on this issue.

736. The Administrative Law Judge finds that the 2016 test year is not unreasonably far removed from the most recent calendar year 2014, and concludes that filing more than 93 days in advance of interim rates should only be allowed in the event September 30 falls on a weekend.

E. Service and Main Extension

737. In its March 31, 1995, Order in Docket No. G999/CI-90-563, the Commission directed each gas utility to address the following six questions in future rate cases relating to the companies' extension rules and policies: (1) Should the free footage or service extension allowance include the majority of all new extensions with only the extremely long extensions requiring a customer contribution-in-aid-of-construction (CIAC)?; (2) How should the Local Distribution Company (LDC) determine the economic feasibility of service extension projects and whether the excess footage charges are collected?; (3) Should the LDC's extension policy be tariffed in number of feet without consideration to varying construction costs among projects or should the allowance be tariffed as a total dollar amount per customer?; (4) Is the LDC's extension charge refund policy appropriate?; (5) Should customers be allowed to run their own service line from the street to the house (or use an independent contractor) if it would be less expensive than having the utility construct the line?; and (6) Should the LDC be required to offer its

[938] NOTICE OF AND ORDER FOR HEARING at 2 (Nov. 30, 2015) (eDocket No. 201511-116011-01).
[939] Ex. 416 at 9-10 (St. Pierre Direct).
[940] Ex. 416 at 10 (St. Pierre Direct).
[941] Ex. 45 at 41-42 (DeMerritt Rebuttal).
[942] Ex. 417 at 3-4 (St. Pierre Surrebuttal).

customers financing for service extension charges? This could be offered as an alternative to paying extension charges in advance of construction.[943]

738. MERC provided responses to all of the questions contained in the Commission's order in Docket No. G999/CI-90-563 in Direct Testimony.[944]

739. MERC conducted the required audit of its main and service extensions to determine whether its extension tariff had been correctly and consistently applied since its last rate case. The result of this review showed that 100 percent of the service lines reviewed met the extension guidelines, and the applicable excess footage fee was properly charged and collected.[945]

740. MERC proposed to continue its currently-approved 75-foot allowance for each stand-alone service extension and its feasibility model for other residential and all commercial and industrial extensions.

741. The Department concluded that MERC's service line extension polices are reasonable and should be approved.[946]

742. No other party offered testimony on this issue.

743. The Administrative Law Judge finds that MERC's service and main extension policies, footage allowance, and feasibility model are reasonable and that MERC demonstrated compliance with its applicable policies.

F. Winter Construction Charges

744. MERC submitted information to address the Commission's requirement in Docket No. G007,011/M-07-1188, that MERC demonstrate that no Winter Construction Charges were being assessed to customers outside the tariffed Winter Construction Charges period (December 1 through April 1), and that no Winter Construction Charges incurred by the Company from any contractors were assessed to ratepayers outside the tariffed Winter Construction Charges period.[947]

745. MERC's review found no winter charge invoices for work done outside the tariffed Winter Construction Charges period and did not request any winter construction charges outside of the tariffed Winter Construction Charge period.[948]

746. No other party filed testimony on this issue.

[943] *In the Matter of an Inquiry into Competition Between Gas Utils. in Minn.*, MPUC Docket No. G999/CI-90-563, ORDER TERMINATING INVESTIGATION AND CLOSING DOCKET at 6-7 (Mar. 31, 1995).
[944] Ex. 13 at 17-22 (Kult Direct).
[945] Ex. 13 at 23, Schedule DGK-2 (Kult Direct).
[946] Ex. 405 at 29 (Peirce Direct).
[947] Ex. 13 at 28 (Kult Direct).
[948] Ex. 13 at 28-29, DGK-5 (Kult Direct).

747. The Administrative Law Judge finds that no adjustment is necessary relative to MERC's winter construction charges and that MERC demonstrated compliance with its winter construction charge tariffs.

G. Farm Tap Safety Inspection Program

748. In Docket No. G011/M-91-989, the Commission required MERC to file in each general rate case a five-year report on the cumulative results of the Farm Tap Safety Inspection Program and any recommendations for future improvements. MERC is in year three of a five-year (2013-2017) farm tap inspection plan.[949]

749. MERC concluded that its Farm Tap Safety Inspection Program continues to be an effective way to discover and repair leaks in farm tap customers' lines.[950]

750. No other party filed testimony on this issue.

751. The Administrative Law Judge finds that the Commission should approve MERC's five-year Farm Tap Safety Inspection Program report and the proposed continuation of the farm tap program.

H. Purchased Gas Adjustment Consolidation (MERC-Albert Lea)

752. On September 30, 2013, MERC and IPL entered into an Asset Purchase and Sale Agreement for the sale of IPL's Minnesota natural gas distribution system and assets, and transfer of service rights and obligations in Minnesota. As discussed above, the Commission approved the transaction on December 8, 2014. In its order, the Commission required that MERC transfer IPL's natural gas customers to MERC's tariffs upon completion of the transaction, but continue to bill transitioned IPL customers for the customer charge and purchased gas adjustment allowed under IPL's tariff structure until MERC's next rate case.[951]

753. In compliance with the Commission's order, MERC proposed to begin charging the former IPL customers MERC's demand and commodity cost of gas through consolidation of the MERC-Albert Lea PGA with the MERC-NNG PGA and that the consolidation be implemented on July 1, 2017, following implementation of final rates.[952]

754. The Department found MERC's proposed consolidation consistent with the methodology MERC used to consolidate the PGA's of its PNG and NMU operating divisions in its 2010 rate case, Docket No. G007,011/GR-10-977.[953]

[949] Ex. 13 at 30 (Kult Direct).
[950] Ex. 13 at 31-32 (Kult Direct).
[951] *In the Matter of a Request for the Approval of the Asset Purchase and Sale Agreement Between Interstate Power and Light Co. and Minn. Energy Res. Corp.*, MPUC Docket No. G-001,011/PA-14-107, ORDER APPROVING SALE SUBJECT TO CONDITIONS at 6 (Dec. 8, 2014).
[952] Ex. 33 at 9-11 (Quick Direct); Ex. 37 at 39-40 (Lee Direct).
[953] Ex. 405 at 25-26 (Peirce Direct).

755. The Department generally agreed with MERC's proposal to implement the consolidation on July 1, 2017, but deferred to the Commission as to whether consolidation should be deferred an additional year to provide former IPL customers time to adjust to the rate changes.[954]

756. MERC agreed that its proposal is consistent with the previously-approved methodology for PGA consolidation, but continues to believe that consolidation on July 1, 2017 is appropriate. MERC incurs administrative expense from maintaining a separate Albert Lea PGA and continuation of a separate PGA for an additional year will only result in additional costs incurred. Given the minimum rate impact of PGA consolidation, MERC does not agree that further delay is justified.[955]

757. No other party offered testimony on this issue.

758. The Administrative Law Judge finds that MERC's proposed consolidation of its MERC-NNG and MERC Albert Lea PGAs is reasonable and should be implemented on July 1, 2017, following implementation of final rates.

I. Joint Service Rates

759. Joint service allows an interruptible customer, either system sales or transportation, to designate a portion of its interruptible service as firm service.

760. In MERC's last rate case, Docket No. G011/GR-13-617, issues were raised related to the concern that MERC's joint service customers may be subsidized by MERC's general sales customers. To address these concerns, MERC proposed to charge Joint Service customers the Firm Demand cost per therm rate currently charged to General Service customers for the firm portion of their joint service.[956]

761. The Department determined that MERC addressed the concerns raised in its last rate case and recommended approval of MERC's joint service rates.[957]

762. No other party offered testimony on this issue.

763. The Administrative Law Judge finds that MERC's joint service rates are reasonable and should be approved.

[954] Ex. 405 at 25-26 (Peirce Direct).
[955] Ex. 39 at 29-30 (Lee Rebuttal).
[956] Ex. 37 at 32-33 (Lee Direct).
[957] Ex. 405 at 26-27 (Peirce Direct).

J. Increase to Curtailment Penalty

764. MERC proposed to revise its tariff to increase the curtailment penalty from $20 per dekatherm to $50 per dekatherm. MERC proposed to increase its curtailment penalty to encourage customers to comply with curtailment requests and minimize unauthorized gas usage, in accordance with Order Point 5 of the Commission's August 24, 2015, Order Accepting Gas Utilities' Annual Automatic Adjustment Reports and 2013-2014 True-Up Proposals and Setting Further Requirements in Docket No. G999/AA-14-580.[958]

765. The Department noted that MERC's proposed tariff updated the tariff sheets to reflect the increase in the curtailment penalty, but did not update the curtailment penalty in all of the applicable service agreements. In response to Department Information Request No. 317, MERC submitted revised service agreements to reflect the penalty increase. Based on those updates, the Department concluded that MERC had complied with the Commission's August 24, 2015 Order and the Department recommended approval.[959]

766. No other party offered testimony on this issue.

767. The Administrative Law Judge finds that MERC's increase to the curtailment penalty from $20 per dekatherm to $50 per dekatherm is consistent with the Commission's August 24, 2015 Order and should be approved.

Based on these Findings of Fact, the Administrative Law Judge makes the following:

CONCLUSIONS OF LAW

1. The Minnesota Public Utilities Commission and the Administrative Law Judge have jurisdiction over the subject matter of this proceeding pursuant to Minn. Stat. § 14.50 and Chapter 216B (2016).

2. The parties and the public received proper and timely notice of the hearings in this matter.

3. Every rate set by the Commission shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial or discriminatory, but shall be sufficient, equitable and consistent in application to a class of consumers. To the maximum reasonable extent, the Commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of Minn. Stat. §§ 216B.164, .241, 216C.05 (2016).[960]

[958] Ex. 37 at 52 (Lee Direct).
[959] Ex. 405 at 30 (Peirce Direct).
[960] Minn. Stat. § 216B.03.

4. The burden of proof is on the public utility to show that a rate change is just and reasonable.[961]

5. Rates set in accordance with this Report would be just and reasonable.

6. Any Findings of Fact more properly designated as Conclusions are hereby adopted as such.

Based on the foregoing Findings of Fact and Conclusions of Law, the Administrative Law Judge makes the following:

RECOMMENDATION

IT IS RECOMMENDED that the Minnesota Public Utilities Commission order that:

1. MERC is entitled to increase its gross annual revenues in the manner and in the amount consistent with the Findings of Fact and Conclusions of Law of this Report.

2. The concepts set forth in these Findings of Fact and Conclusions of Law should govern the mathematical and computational aspects of the Findings and Conclusions. Any computations in the Report that are in conflict with the conclusions of this Report should be adjusted so as to conform to the conclusions of the Report.

Dated: August 19, 2016

JEANNE M. COCHRAN
Administrative Law Judge

[961] Minn. Stat. § 216B.16, subd. 4 (2016).

NOTICE

Notice is hereby given that exceptions to this Report, if any, by any party adversely affected must be filed under the time frames established in the Commission's rules of practice and procedure, Minn. R. 7829.2700, .3100 (2015), unless otherwise directed by the Commission. Exceptions should be specific and stated and numbered separately. Oral argument before a majority of the Commission will be permitted pursuant to Minn. R. 7829.2700, subp. 3. The Commission will make the final determination of the matter after the expiration of the period for filing exceptions, or after oral argument, if an oral argument is held.

The Commission may, at its own discretion, accept, modify, or reject the Administrative Law Judge's recommendations. The recommendations of the Administrative Law Judge have no legal effect unless expressly adopted by the Commission as its final order.

OAH 68-2500-32993
MPUC Docket No. G011/GR-15-736

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota

ATTACHMENT A
SUMMARY OF PUBLIC COMMENTS

Pursuant to Minn. R. 7829.1100 (2015), the Administrative Law Judge conducted public hearings on March 28, March 29, and March 30, 2016. The public hearings were held to elicit public comment regarding the proposed rate increase by MERC.

The first public hearing on MERC's proposed rate increase was held on March 28, 2016 at the Cloquet Chamber of Commerce in Cloquet, Minnesota. The second public hearing was held on March 29, 2016 at Rochester City Hall in Rochester, Minnesota. The third public hearing was held on March 29, 2016 at the Albert Lea City Offices in Albert Lea, Minnesota, and a fourth Public hearing was held on March 30, 2016 at Dakota County Technical College in Rosemount, Minnesota.

The public was also provided an opportunity to submit written comments, either electronically or by U.S. mail, until April 15, 2016. Written comments were filed in the Commission's eDockets system.

A summary of the comments received at the public hearings and in writing follows below:

I. Summary Comments at the Public Hearings

<u>Cloquet, Minnesota Public Hearing – Cloquet Chamber of Commerce</u>

At the public hearing in Cloquet, Minnesota, nine (9) members of the public attended and six (6) offered comments for the hearing record.

Susan Pedersen, lives in Moose Lake and owns a farm between Pine City and Mora where she receives farm tap service from the Company. Ms. Pederson is opposed to the proposed rate increases and expressed concern over how MERC implements its charges for farm tap customers. In her view, MERC has been overcharging farm tap customers and she would like to see MERC charge only for the actual Ccfs that are delivered to the meter. She also expressed concern about MERC's billing practices and customer service.[962]

David Bartrick questioned why rates are increasing when natural gas is at its lowest price in 17 years. He expressed concern that, as the price of natural gas has fallen, the price charged by MERC has stayed the same. In his view, a rate increase is not justified.[963]

David Johnson is a ratepayer from Cloquet who owns several apartment buildings. He expressed disappointment that all of his rental properties must be billed and paid for individually and cannot be consolidated on one bill. Mr. Johnson also raised concern about the difficulty he has reading his billing statements due to the small font. In addition, Mr. Johnson believes that the notice of the public hearing was inadequate.[964]

Karen Durfee opposed the rate hike. She indicated that natural gas prices have been decreasing and a rate increase is unwarranted. In her view, the gas delivery system is adequate and any improvements should be minimal.[965]

Lorna Hanes opposed the rate increase and noted that the money would be better spent on alternative energy solutions.[966]

Debra Topping expressed concern that low-income members of the community could not afford the rate increase. Ms. Topping explained that her daughter, who lives in Cloquet, has a limited budget and cannot afford a rate increase.[967]

Rochester, Minnesota Public hearing – Rochester City Hall

At the public hearing in Rochester, Minnesota, six (6) members of the public attended and two (2) offered comments for the hearing record.

Thomas Deboer, a ratepayer from Rochester, described the community's heavy reliance on natural gas and noted that demand for natural gas is increasing due to the retirement of coal-fired power plants. In his view, inability to meet demand would be detrimental to the community and it is imperative that MERC invest in infrastructure and maintenance necessary to meet future demand.[968] Mr. Deboer supported MERC's request for a rate increase.[969]

Anna Richey, a resident of Rochester and vice chair of the Rochester Energy Commission, raised concerns about the disproportionate effects of the rate increase on

[962] Cloquet Public Hearing Transcript at 21-31 (Mar. 28, 2016).
[963] *Id.* at 31-38.
[964] *Id.* at 38-46.
[965] *Id.* at 46-49.
[966] *Id.* at 49-51.
[967] *Id.* at 51-56.
[968] Rochester Public Hearing Transcript at 21-32 (Mar. 29, 2016).
[969] *Id.*

low and fixed income residents. Her belief is that MERC can find alternative ways of financing the improvements.[970]

Albert Lea, Minnesota Public Hearing – Albert Lea City Offices

At the public hearing in Albert Lea, Minnesota, six (6) members of the public attended and four (4) offered testimony for the hearing record.

Alan Bakken, an agricultural business owner from Albert Lea Township, expressed concern that the proposed rate increases will negatively affect the already struggling agricultural community. His business uses natural gas to dry crops and he estimates that his cost will increase by 27 percent.[971]

Dave McKinney, a resident from Albert Lea, expressed concern that the rate increase is too high. In his view, MERC and its parent company WEC Energy Group, have increased their net income in recent years and need to provide more information as to where the money from the rate increase will be spent.[972]

Harold Kamrath, a resident from Albert Lea, opposed any rate increase. His concern is that the increase comes at a time when residents have been faced with tax increases from the city and county while wages and Social Security payments have stayed the same.[973]

Ryan Nolander, the executive director of the Economic Development Agency in Albert Lea, explained that MERC's proposal would increase rates for small commercial industrial customers in the former IPL service area by 47 percent, and large commercial industrial customers in the former IPL service area by over 23 percent. In his view, the proposed rate increases will hurt existing businesses in Albert Lea, which was formerly served by IPL, and will make it difficult to attract new businesses to the area.[974]

Rosemount, Minnesota Public Hearing – Dakota County Technical College

No members of the public were in attendance at the public hearing in Rosemount.

II. Summary of the Written Comments

In addition to the testimony at the hearings, the Commission received over 40 written comments by electronic or first class mail before the close of the comment period on April 15, 2016.

[970] *Id.* at 32-35.
[971] Albert Lea Public Hearing Transcript at 20-23 (Mar. 29, 2016).
[972] *Id.* at 23-26.
[973] *Id.* at 26-30.
[974] *Id.* at 30-32.

John Roemer expressed concern that MERC has not provided enough detail on the rate increase. He recommended that any increase be rejected until a better explanation is provided.[975]

Tony Cy asserted that the proposed rate increases are excessive and unjustified. He stated that the Company's mailing, entitled "Important Information About Your Rates," did not provide specific reasons for the proposed rate increases. He expressed concern for Minnesota families who are struggling to meet utility costs. He requested that the rate increases be denied until MERC can provide detailed numbers justifying the increases.[976]

David Roden agreed with Tony Cy that the Company's mailing failed to explain the specific reasons for the proposed rate increases, and requested that any rate increase be denied until MERC can prove the need for the increase.[977]

Lyne Roginski opposed the rate increase. She noted that she did not receive any increase in her Social Security income this year, and believes that MERC cannot justify an increase based on inflation.[978]

Steve Kay suggested that the rate increase should be denied. He believes that there has not been any inflation to justify the increased rates and also noted that natural gas prices have not increased.[979]

Zekaleah Delz asserted that an increase will be hard on people that are retired and living on a fixed income. He also noted that there has been no inflation to justify an increase and stated any increased costs can be written off as "business expenses."[980]

Dick Hegal asked that the Commission deny MERC's request. In his view, there should be no rate increase based on inflation because there was no increase for Social Security recipients.[981]

Rick Bichel shared his concern that wages are not increasing and such an excessive increase will adversely affect MERC's customers.[982]

Tom Smith requested that the increase be rejected. He believes the increase is unjustified due to the fact that the price of natural gas has fallen.[983]

[975] Comment by John Roemer (Jan. 12, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[976] Comment by Tony Cy (Jan. 14, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[977] Comment by David Roden (Jan. 28, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[978] Comment by Lynne Roginski (Feb. 1, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[979] Comment by Steve Kay (Feb. 4, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[980] Comment by Zekaleah Delz (Feb. 8, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[981] Comment by Dick Hegal (Feb. 18, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[982] Comment by Rick Bichel (Feb. 21, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[983] Comment by Tom Smith (Feb. 22, 2016) (SpeakUp) (eDocket No. 20164-120493-01).

Richard Horihan commented that the increase should be denied because the distribution and customer charges are increasing at unsustainable rates.[984]

Brad Becker is not in favor of another rate increase. He believes that the addition of new customers and falling price of natural gas should allow MERC to operate sustainably without a rate increase. He noted also that his wife has not had a raise in the last six years, and suggested that MERC do more to operate within its existing budget as it customers have had to do.[985]

Aaron Thun also expressed concern about MERC's request for another rate increase and asked the Commission to deny the request. In his view, MERC is asking for a much higher increase than it needs. He believes with the drop in natural gas prices, the rates should be decreased.[986]

Barry Reburn urged the Commission to deny the request, citing the drop in natural gas prices over the last three years.[987]

Alan Anderson suggested that the request be denied. He explained that with natural gas prices falling, an increase would be unjustified. He noted that he is a retiree living on Social Security, and did not receive any increase in his Social Security income this year. He suggested that the Commission not grant any increase for at least a couple years.[988]

Robert Nyman asked that the Commission deny the request. His concern is that the cost of living has been rising while government pensions and Social Security have stayed the same. In his view, this rate hike is unjustified and will have a great impact on fixed income residents.[989]

Gary Skelton urged the commission to deny MERC's request. In his view, there should be no rate increase based on inflation because there was no increase for Social Security.[990]

Ken Witte argued that more information should be supplied from MERC to explain why the rate increase is deserved. In his view, MERC should be experiencing record profits at current rates and does not need to increase rates.[991]

[984] Comment by Richard Horihan (Feb. 22, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[985] Comment by Brad Becker (Feb. 25, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[986] Comment by Aaron Thun (Feb. 25, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[987] Comment by Barry Reburn (Feb. 26, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[988] Comment by Alan Anderson (Feb. 29, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[989] Comment by Robert Nyman (Mar. 9, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[990] Comment by Gary Skelton (Mar. 9, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[991] Comment by Ken Witte (Mar. 10, 2016) (SpeakUp) (eDocket No. 20164-120493-01).

Dave Herbeck expressed concern that consumers should not be seeing a rate increase when natural gas is at an all-time low. He suggested that customers should be given a rate decrease.[992]

Harry Schuur agreed that customers should be receiving a rate decrease rather than an increase.[993]

Robert Langen believes that MERC should make cutbacks to its costs rather than increasing its rates. He noted that senior citizens have not had an increase in Social Security payments for a number of years.[994]

Timothy Matson expressed concern that the brochure sent out by MERC did not explain the reasoning behind the increase. In his view, the increase is going to hurt many residents who live on a fixed income.[995]

Cole Pestorious urged the Commission to deny the request and explained that the increase will greatly impact producers in the agriculture industry. He asserted that natural gas prices are similar to what they were in the 1990's and argued a rate increase is unjustified.[996]

Kris Pierce suggested that the brochures sent out by MERC were very misleading. She believes that the increase would be difficult for residents and businesses to absorb and questioned whether the capital expenditures by MERC are really necessary.[997]

Pamela Sander, a small business owner in Albert Lea, is not opposed to some increase but stated that the proposed increase for customers in the Albert Lea area is too large. She explained that the proposed rate changes will increase her business costs dramatically.[998]

Chad Vogt requested that the proposed rate increase be denied. In his view, the increase will place a large burden on families and small businesses, which is unjustified due to the price of natural gas being low.[999]

Jeff Woodside, a ratepayer and business owner, explained that the increase would impact the ability of his business to remain competitive in the marketplace because his company is a high volume user of natural gas. He believes the proposed rate increase will hinder his ability to provide higher wages and better benefits to his employees. He also noted that the rate increases will increase the cost of his products to consumers.[1000]

[992] Comment by Dave Herbeck (Mar. 10, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[993] Comment by Harry Schuur (Mar. 14, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[994] Comment by Robert Langen (Mar. 17, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[995] Comment by Timothy Matson (Mar. 29, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[996] Comment by Cole Pestorious (Mar. 30, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[997] Comment by Kris Pierce (Apr. 11, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[998] Comment by Pamela Sander (Apr. 12, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[999] Comment by Chad Vogt (Apr. 12, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[1000] Comment by Jeff Woodside (Apr. 13, 2016) (SpeakUp) (eDocket No. 20164-120493-01).

Edward Zachary argued that the rate increase should be denied. He believes that the increased revenue is unnecessary, and that MERC should be able to continue operating without increasing rates.[1001]

Charlotte McCann asked that the request for a rate increase be denied. In her view, MERC is passing along unnecessary costs to the consumers. She believes that MERC should bear the burden of any additional costs.[1002]

Steve Wilson recommended that the commission deny MERC's request for increased rates. He noted that the proposed rate increase would adversely affect Zinpro Corporation, where he works. He noted that MERC raised its rates recently and questioned whether another rate increase is really necessary. He noted that if this proposed rate increase is approved, the operating costs for this facility will increase by over $40,000 annually in just the two years. He is concerned that the rate increase is excessive, unjustified, and will have a negative impact on his business.[1003]

Marco Polo recommended that with natural gas prices being so low, MERC should be decreasing rates. He also raised a concern that the bills provided by MERC are complicated and confusing, particularly the fees added to the base cost of service.[1004]

Paul Weber, a farmer and ratepayer asked that the rate increase be denied. He stated that MERC has poor customer service. He noted that he has had trouble with meter reading. In addition, MERC has not been responsive to his request to have a larger meter and regulator installed so that he can operate his grain dryer with natural gas.[1005]

Roger Swanson requested that MERC justify the rate increase. According to him, MERC's costs have gone down and this increase is unwarranted.[1006]

Dustin Trail opposed the increase. In his view, natural gas is 6.5 times cheaper than it was in 2008 and the increase cannot be justified. He requested that the rates stay the same or be decreased.[1007]

[1001] Comment by Edward Zachary (Apr. 13, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[1002] Comment by Charlotte McCann (Apr. 14, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[1003] Comment by Steve Wilson (Apr. 14, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[1004] Comment by Marco Polo (Apr. 14, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[1005] Comment by Paul Weber (Apr. 14, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[1006] Comment by Roger Swanson (Apr. 15, 2016) (SpeakUp) (eDocket No. 20164-120493-01).
[1007] Comment by Dustin Trail (Apr. 15, 2016) (SpeakUp) (eDocket No. 20164-120493-01).

David Broman suggested that the rates should not be increased while natural gas prices are decreasing.[1008]

Mark Roalson asserted that there is no justification for a rate increase by MERC and that any increase will have a great impact on fixed income residents.[1009]

D. Marinella suggested that Social Security recipients have not received a cost of living increase, and MERC is not justified in raising rates.[1010]

James Fredrickson opposed the increase on the basis that MERC's prices are already too high. In his view, this increase is unjustified and will have a detrimental impact on the public.[1011]

Richard Horihan expressed a concern that the notice he received from MERC was late and did not separate customer charges from per therm distribution charges. He believes the rate increases are excessive and urged the commission to deny the request.[1012]

Ward Are explained that the price of natural gas has fallen while the supply has increased. As a result, he believes the rate increase is unjustified and asked that the Commission deny the request.[1013]

Gloria Hill opposed the increase. She believes that the increase will have a negative impact on senior citizens who have fixed incomes. She noted that that Social Security recipients have not seen an increase in their income, and many senior citizens already have a difficult time paying their bills. She stated that some even go without medication as a result. She believes that a rate increase based on inflation is unjustified.[1014]

Rose Ward requested that the Commission deny the rate increase. In her view, people are already paying too much for their utility bills.[1015]

David and Mary Styczinski stated that a rate increase should not be approved at a time when natural gas prices are at a historic low. They suggested that MERC should find ways to cut costs instead of increasing the rates.[1016]

Alan Lindeman, who lives in Albert Lea, urged the Commission to deny the request. As a Social Security recipient, he did not receive a raise but his cost of living has been rising. He noted that he has taken a number of steps to reduce his gas usage,

[1008] Comment by David Broman (Mar. 26, 2016) (eDocket No. 20164-120493-01).
[1009] Comment by Mark Roalson (Mar. 15, 2016) (eDocket No. 20164-120493-01).
[1010] Comment by D. Marinella (Jan. 29, 2016) (eDocket No. 20164-120493-01).
[1011] Comment by James Fredrickson (Feb. 9, 2016) (eDocket No. 20164-120493-01).
[1012] Comment by Richard Horihan (Feb. 22, 2016) (eDocket No. 20164-120493-01).
[1013] Comment by Ward Are (Feb. 22, 2016) (eDocket No. 20164-120493-01).
[1014] Comment by Gloria Hill (Feb. 17, 2016) (eDocket No. 20164-120493-01).
[1015] Comment by Rose Ward (Mar. 4, 2016) (eDocket No. 20164-120493-01).
[1016] Comment by David and Mary Styczinski (Mar. 1, 2016) (eDocket No. 20164-120493-01).

such as adding more insulation and installing new windows. He believes that a rate increase is unwarranted.[1017]

[1017] Comment by Alan Lindeman (Feb. 27, 2016) (eDocket No. 20164-120493-01).

MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

PO Box 64620
Saint Paul, MN 55164-0620
mn.gov/oah

PH (651) 361-7900
TTY (651) 361-7878
FAX (651) 539-0310

August 19, 2016

See Attached Service List

Re: In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota

OAH 68-2500-32993
MPUC G-011/GR-15-736

To All Persons on the Attached Service List:

Enclosed and served upon you is the Administrative Law Judge's **FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION** in the above-entitled matter.

If you have any questions, please contact my legal assistant Denyse Johnson at (651) 361-7888 or denyse.johnson@state.mn.us, or facsimile at (651) 539-0310.

Sincerely,

Jeanne Cochran

JEANNE M. COCHRAN
Administrative Law Judge

JMC:dj
Enclosure
cc: Docket Coordinator

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
PO BOX 64620
600 NORTH ROBERT STREET
ST. PAUL, MINNESOTA 55164

CERTIFICATE OF SERVICE

In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota	OAH Docket No.: 68-2500-32993 MPUC G-011/GR-15-736

Denyse Johnson, certifies that on August 19, 2016 she served the true and correct **FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION** by eService, and U.S. Mail, (in the manner indicated below) to the following individuals:

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes
Elizabeth	Brama	ebrama@briggs.com	Briggs and Morgan	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No
Jeanne	Cochran	Jeanne.Cochran@state.mn.us	Office of Administrative Hearings	P.O. Box 64620 St. Paul, MN 55164-0620	Electronic Service	Yes
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	Electronic Service	Yes
Darcy	Fabrizius	Darcy.fabrizius@constellation.com	Constellation Energy	N21 W23340 Ridgeview Pkwy Waukesha, WI 53188	Electronic Service	No
Emma	Fazio	emma.fazio@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	Yes
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department	85 7th Place E	Electronic	Yes

			of Commerce	Ste 500 Saint Paul, MN 551012198	Service	
Robert	Harding	robert.harding@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 55101	Electronic Service	Yes
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	Yes
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No
Amber	Lee	ASLee@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	2665 145th St W Rosemount, MN 55068	Electronic Service	No
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes
Peter	Madsen	peter.madsen@ag.state.mn.us	Office of the Attorney General-DOC	Bremer Tower, Suite 1800 445 Minnesota Street St. Paul, Minnesota 55101	Electronic Service	Yes
Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St Paul, MN 55101-2131	Electronic Service	Yes
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	Yes
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	Ste 122 9100 W Bloomington Frwy Bloomington, MN 55431	Electronic Service	Yes
Kristin	Stastny	kstastny@briggs.com	Briggs and Morgan, P.A.	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Petition of Southwest Gas Corporation to establish a regulatory asset to accumulate the return on investment, incremental depreciation, and property taxes related to the accelerated replacement of early vintage plastic pipe in Southern Nevada.	)	Docket No. 12-02019
Application of Southwest Gas Corporation for authority to increase its rates and charges for natural gas service for all classes of customers in Southern and Northern Nevada.	)	Docket No. 12-04005

At a general session of the Public Utilities Commission of Nevada, held at its offices on March 14, 2013.

PRESENT: Chairman Alaina Burtenshaw
Commissioner Rebecca D. Wagner
Commissioner David Noble
Assistant Commission Secretary Breanne Potter

SECOND MODIFIED FINAL ORDER

The Public Utilities Commission of Nevada ("Commission") makes the following findings of fact and conclusions of law:

I. INTRODUCTION

Southwest Gas Corporation ("SWG") filed a Petition with the Commission, designated as Docket No. 12-02019, to establish a regulatory asset to accumulate the return on investment, incremental depreciation, and property taxes related to the accelerated replacement of early vintage plastic pipe in Southern Nevada.

SWG also filed an Application with the Commission, designated as Docket No. 12-04005, for authority to increase its rates and charges for natural gas service for all classes of customers in southern and northern Nevada.

II. SUMMARY

The Commission denies SWG's Petition and grants SWG's Application as modified by this Order. The Commission grants a return on equity ("ROE") of 9.30 percent in the Northern Nevada Division ("NND") and 10.0 percent in the Southern Nevada Division ("SND"), which

Staff's Position

73. Staff did not address this issue in its direct testimony.

Commission Discussion and Findings

74. NAC 704.222 provides that changes in rates authorized by variable interest securities are effective at the same time as a change in the rates resulting from a general rate case. The Commission approves SWG's request to modify its VIER mechanism. In the 2011 annual rate proceeding to reset the VIER rates, SWG testified that the variable interest debt in the VIER mechanism saved ratepayers $15.8 million from September 2004 to April 2011 compared to the fixed rate alternatives and no party challenged this testimony. (Docket No. 11-06003, Exhibit 1 at 5.) These savings demonstrate that the VIER mechanism has provided a net benefit to ratepayers since its inclusion in rates. Based on these past savings, the Commission finds that the addition of the $50 million 2009 Clark County Series A IDRBs to the VIER mechanism is reasonable.

D. Return on Equity ("ROE")

SWG's Position

i. Hearing (September 10-14, 2012)

75. SWG requests that the Commission authorize an increase from its current 10.15 percent ROE to 10.65 percent. (Exhibit 21 at 22; Exhibit 24 at 5, 53.) SWG states that its cost of equity is currently in the range of 10 to 10.75 percent, and that its proposed ROE of 10.65 percent is conservative, reasonable and appropriate. (Exhibit 24 at 5, 7, 53; Exhibit 21 at 22.) SWG states that the proposed ROE is based on quantitative and qualitative analyses performed

by SWG, and accounts for the regulatory and capital environment in which SWG operates.[4] (Exhibit 24 at 5-7, 53.)

76. Because the ROE is a market-based concept, SWG also utilized a proxy group in estimating the ROE. (*Id.* at 10.) SWG selected ten comparable companies to include in the proxy group ("Proxy Group"), a number sufficiently large enough to be representative of SWG's ROE, but excluded SWG from the analysis to avoid circular logic.[5] (*Id.* at 12-13.)

77. The following table summarizes the range of ROEs calculated by SWG after applying the following common estimation methodologies: constant and multi-stage discounted cash flow ("DCF"), capital asset pricing model ("CAPM"), and bond yield plus risk premium. (*Id.* at 5.)

Methodology	Suggested Range
Constant DCF	9.12% to 11.04%
Multi-Stage DCF	9.53% to 11.13%
CAPM	10.00% to 11.00%
Bond Yield + Risk Premium	10.18%
Recommended Range	**10.00% to 10.75%**

(*Id.* at 6-7, 24, 31.)

78. SWG's DCF analyses[6] included the retention growth method, which is a widely used method for estimating long-term growth. (Exhibit 24 at 19.) SWG incorporated the forecasted earnings growth rates published by three well-known analysts.[7] (*Id.* at 17-18.) SWG

[4] According to SWG, given its "BBB+" credit rating and Value Line common stock safety ranking of 3.0, it is a riskier utility than its proxy companies which have a weighted "A-" credit rating and a weighted 1.7 common stock safety ranking. (Exhibit 21 at 19-20, Att. TKW-2 at 1, and Att. TKW-3.)
[5] SWG's criteria for selecting utilities to include in the Proxy Group consisted of those companies that: (a) are publicly traded; (b) are classified by Value Line (an independent investment research and financial publishing firm) as "Natural Gas" or "Natural Gas Utilities;" (c) consistently pay quarterly cash dividends; (d) are covered by at least two utility industry equity analysts; (e) have investment grade senior bond and/or corporate credit ratings from S&P; (f) have regulated natural gas utility operations which provide at least 60 percent of net operating income; and (g) are not a party to a merger or other significant transaction. (Exhibit 24 at 10, 12.)
[6] In the DCF analyses, SWG used stock data ending February 29, 2012. (*Id.* at 16.)
[7] Specifically, the consensus long-term earnings growth estimates published by Zacks, First Call, and Value Line. (*Id.* at 19.)

estimated the third-stage dividend growth rate at 5.79 percent in the multiple-stage DCF. (*Id.* at 23.) This 5.79 percent consists of the 3.24 percent real growth in the gross domestic product ("GDP") for the period 1926 to 2011,[8] and the inflation rate of 2.47 percent which is the spread between yields on long-term nominal U.S. Treasury securities and long-term Treasury Inflation Protected Securities. (*Id.*) SWG notes that the second-stage dividend growth rate is a transitional rate developed using the first and third-stage rates. (*Id.* at 23-24.)

79. SWG's "high" DCF ROE estimates were calculated using the maximum earnings growth rate reported for each company in the Proxy Group. (*Id.* at 20.) SWG's "low" ROE estimates were calculated with a similar methodology, but using the minimum reported earnings growth rate. (*Id.*)

80. SWG's CAPM methodology is a risk premium model, which provides that the ROE is equal to the risk-free rate of return plus the beta (market risk premium), with beta representing the relative volatility of the utility in comparison to the market as a whole. (*Id.* at 25-26.) The risk-free rate of return is represented by the interest rate on long-term U.S. Treasury securities. (*Id.* at 26, Att. RBH-6.) SWG's analysis to estimate the risk-free rate utilized two 30-year U.S. Treasury Bond yields, including the 30-day average yield (3.09 percent) and the near-term projected yield (3.50 percent). (*Id.* at 27.) SWG asserts that using these forward-looking estimated market risk premiums is necessary because the Federal Reserve policy of maintaining low long-term interest rates together with investors seeking low risk securities have caused historical market risk premiums to remain below pre-financial crisis levels. (*Id.* at 26-27.) SWG estimated the forward-looking market risk premiums at 8.62 percent, 9.13 percent, and 10.43 percent, while the historic market risk premium was only 6.7 percent. (*Id.* at 27-29, Att. RBH-4.)

[8]Bureau of Economic Analysis, February 29, 2012 update. (*Id.* at 23.)

81. SWG used three beta approaches in its CAPM analysis, including Bloomberg (calculated using two years of data), Value Line (calculated using five years of data), and one that SWG calculated using more recent information. (*Id.* at 29.) The three betas are 69.5 percent (Value Line), 79.5 percent (Bloomberg), and 82.9 percent (SWG). (*Id.* at Att. RBH-6.) The Value Line and SWG betas showed an increased correlation between the Proxy Group and the market. (*Id.* at 29.)

82. SWG states that the bond yield plus risk premium method is equal to the difference between the authorized ROE and the then-prevailing 30-year U.S. Treasury Bond yield. (*Id.* at 32.) SWG developed the risk premium using a regression analysis of rate case decisions issued in 1980 through January 2012. (*Id.* at 32-33.) For the risk-free rate of return SWG used the near-term forecasted U.S. Treasury 30-year bond yield (3.50 percent). (*Id.* at 34.)

83. SWG asserts that equity investors consider whether SWG is materially more risky than other available investments by examining the rate mechanisms that are available to SWG to reduce risk in comparison to other companies—in this instance, the Proxy Group. (Tr. at 155-58.) All companies in the Proxy Group have some form of decoupling mechanism in place. (Exhibit 24 at 47, Att. RBH-8.) SWG performed analyses to determine whether equity investors viewed SWG as less risky than the companies in the Proxy Group subsequent to its implementation of revenue decoupling. (*Id.* at 47-50.) The analyses, such as Value Line's equity rankings and earnings predictability indicators and a comparison of SWG's risk beta to the Proxy Group beta, indicate that SWG is not viewed to be less risky than the Proxy Group. (*Id.* at 50.) Thus, SWG asserts that no adjustment to the ROE is warranted due to its current general revenue adjustment ("GRA") mechanism. (*Id.* at 51.)

84. SWG also contends that no adjustment to the requested 10.65 percent ROE will be necessary to reflect authorization of its proposed gas infrastructure replacement mechanism ("GIR"). (*Id.* at 53.) This is because the 2012 American Gas Association ("AGA") study report indicates that all companies in the Proxy Group have some form of infrastructure replacement mechanism in place. (*Id.*)

BCP's Position

85. BCP recommends a ROE of 9.2 percent and an adjustment of 25 basis points downward to reflect the impacts of decoupling. BCP contends that SWG's ROE is overstated and recommends an ROE of 9.2 percent, based on an estimated cost of equity ranging from 8.7 to 9.7 percent. (Exhibit 26 at 3, 5.) BCP acknowledges that this recommendation does not take into consideration SWG's GRA. (*Id.* at 47.) Rather, BCP recommends that a 25 basis point reduction be made to the Commission-approved ROE for the GRA, which would result in an ROE of 8.95; however, BCP states that the final ROE should not fall below 8.70 percent. (*Id.*) BCP asserts that its recommended ROE, with or without an adjustment for the GRA, will provide SWG with sufficient cash flow and earnings to achieve the necessary financial metrics for its current credit ratings. (*Id.* at 70.)

86. BCP argues that current economic conditions fail to support higher utility ROEs. (*Id.* at 7.) Since September 2008, government intervention responding to the financial and economic turmoil has reduced the cost of capital, as evidenced by reduced utility borrowing costs and declining authorized ROEs. (*Id.* at 7-8.) BCP further argues that it is reasonable to expect lower than historical long-term interest rates to continue into the foreseeable near-term. (*Id.* at 11-12.) BCP notes the observed decline in long-term interest rates, which are near six-year lows. (*Id.* at 11.)

87. BCP attributes the continued decline in longer-term interest rates to the U.S. Federal Reserve's monetary policy, beginning in December 2008, to maintain a near-zero federal funds rate (i.e., 0 to 0.25 percent). (*Id.* at 8.) In June 2012, the U.S. Federal Reserve issued a press release expressing its intent to continue this monetary policy through the end of 2014. (*Id.* at 10.) The Federal Reserve refers to slower growth than previously estimated as the basis for extending this date (previously scheduled to terminate in mid-2013). (*Id.*) Specifically, during a June 2012 meeting, the Federal Reserve Bank's Federal Open Market Committee forecasted economic growth to be as follows:

	2012	2013	2014	Long-Run
GDP June Estimate	1.9% - 2.4%	2.2% - 2.8%	3.0% - 3.5%	2.3% - 2.5%
GDP April Estimate	2.4% - 2.9%	2.7% - 3.1%	3.1% - 3.6%	2.3% - 2.6%
Inflation June Estimate	1.2% - 1.7%	1.5% - 2.0%	1.5% - 2.0%	2.0%
Inflation April Estimate	1.9% - 2.0%	1.6% - 2.0%	1.7% - 2.0%	2.0%

(*Id.*)

88. BCP further notes that Moody's, a credit rating agency, issued a general industry report in July 2012 stating that the gas utility industry outlook is stable, which is attributed in part to the low interest rate environment. (*Id.* at 14-15.)

89. BCP developed its recommended ROE using three of the same methodologies used by SWG, including DCF, CAPM, and Bond Yield Plus Risk Premium. (*Id.* at 31.) BCP then applied these methodologies to SWG's Proxy Group. (*Id.* at 32.) The following table summarizes the results of BCP's analyses.

Methodology	Range[9]	Mid-Point
Constant Growth DCF	9.6% to 9.6%	
Two-Stage DCF	8.7% to 9.1%	
DCF	8.7% to 9.4%	9.1%
Risk Premium	9.3% to 9.7%	9.4%

[9] The "range" consists of the average and median values calculated for the comparable Proxy. (Exhibit 26 at Att. DJL-6, DJL-7, and DJL-9.)

CAPM	8.7% to 9.1%	8.9%
BCP Recommendation	**8.7% to 9.7%**	**9.2%**

(*Id.* at 41, 43, 46-47, Att. DJL-6, Att. DJL-7, Att. DJL-9.)

90. BCP states that the DCF methodologies are the best analytical techniques for measuring a utility's cost of common equity. (*Id.* at 31.) BCP asserts that the risk premium and CAPM methodology results must be evaluated with caution because these methodologies are subject to measurement uncertainties, including the time period used to determine the premium. (*Id.* at 42.) Further, these methodologies presume that historical debt/equity risk spreads, measured over many decades, are relevant to the current capital market requirements. (*Id.*)

91. BCP states that its constant growth DCF analysis[10] dividend growth rate was developed using forecasted earnings growth rates from the analysts referenced by SWG.[11] (*Id.* at 38.) BCP asserts that SWG's 4.9 to 6.1 percent growth rate range is both outdated and overstated. (*Id.* at 39.) BCP's analysis results in a range of average and median forecasted growth rates for SWG and its Proxy Group between 3.0 to 5.5 percent. (*Id.*)

92. BCP asserts that SWG's multi-stage DCF analysis is also overstated because the underlying GDP growth rate and inflation rate exceed current forecasted rates. (*Id.* at 71.) Correcting for these errors would result in a multi-stage DCF analysis with results similar to BCP's two-stage DCF analysis. (*Id.* at 72.) For stage one, BCP used Value Line's forecasted dividend growth rate, and for stage two BCP used the Proxy Group average of 5.1 to 5.5 percent long-run earnings growth estimate. (*Id.* at 40.)

[10] In this analysis, BCP used the stock data for the six-week period ending July 31, 2012. (*Id.* at 36.)
[11] Value Line, Zacks, and First Call. (*Id.* at 38.)

93. BCP's risk premium analysis consisted of comparing authorized ROEs for electric utilities to three different debt security yields[12] for the period 1980 to 2011. (*Id.* at 42-43.)

94. BCP's CAPM analysis used the forecasted 30-year U.S. Treasury Bond yield rate (3.9 percent) as the risk-free rate, rather than the current or 3-month historical average that is generally employed. (*Id.* at 44.) BCP states that using the forecasted 30-year U.S. Treasury bond yield rate recognizes that forecasted yields for the next 36-month period are significantly higher than the current yields (3.9 percent compared to rates approaching 2.5 percent). (*Id.*) BCP used two market risk premiums, the historical risk premium (1926 to 2011) of 5.7 percent and an estimated 7.9 percent, which was derived by replacing the historical government bond yield (1926 to 2011) with the forecasted 3.9 percent rate. (*Id.* at 44-45.)

95. Additionally, BCP employed an empirical CAPM ("ECAPM") technique. (*Id.* at 46.) BCP states that some have argued that the CAPM understates the ROE for a utility with a beta less than 1 and overstates those entities with a beta greater than 1. (*Id.*) BCP used an adjustment factor of 25 percent for the direct assignment of the market risk premium to SWG, with the beta-determined risk premium weighted at 75 percent. (*Id.*)

96. BCP recommends that, if the decoupling process is continued, the Commission should also continue to reduce the ROE by 25 basis points. (*Id.* at 26.) This adjustment recognizes a shifting of business risk from the shareholders to the ratepayers. (*Id.* at 5.) BCP asserts that cost recovery mechanisms, such as balancing accounts and decoupling, stabilize utility cash flow, reduce risk and support creditworthiness. (*Id.* at 16-17.) BCP states that decoupling also reduces the risk of revenue and profit erosion between rate cases. (*Id.* at 17.) BCP notes that two credit rating agencies, Standard & Poor's ("S&P") and Moody's, have

[12] Namely, Moody's Average Public Utility Bond Yield, Baa corporate bond yields, and 30-year U.S. Treasury yields. (*Id.* at 42-43.)

indicated that such non-general rate recovery mechanisms reduce risk. (*Id.* at 18.) S&P's April 2012 credit rating report for SWG identifies steady cash flow and decoupling mechanisms as positive aspects. (Exhibit 26, App. B at 1.) Moody's March 2012 credit rating report for SWG identifies timely recovery of variable cost of service and decoupling as positive aspects. (*Id.* at 4.) Moreover, BCP notes that SWG acknowledged that credit rating agencies view these mechanisms positively. (*Id.* at 23-24.)

Staff's Position

97. Staff recommends the Commission authorize a 9.1 percent ROE. (Exhibit 29 at 1.) Staff states that it calculated a reasonable range of ROEs between 8.7 to 9.5 percent. (*Id.* at 3.) Staff contends its ROE analysis comports with U.S. Supreme Court decisions guiding ROE determination. (*Id.* at 6.) Staff's recommendation incorporates the proposed GIR because more than half of the companies in the Proxy Group already have infrastructure replacement mechanisms. (*Id.* at 35.) Further, Staff's recommendation addresses the issue of potentially "abnormal" low interest rates (e.g., "flight to quality"—investors seeking safe investments amid Europe economic crisis) by giving less weight to the CAPM methodology. (*Id.* at 31.)

98. Staff recommends the Commission consider current economic and market conditions in its determination of the ROE. (*Id.* at 28.) Economic recovery since the "Great Recession" has been slow, and slow economic growth is projected into the future. (*Id.* at 29.) The following table demonstrates this point:

	Historical (1929-2011)	**Forecasted (2010-2035)**
Nominal GDP Growth	6.28%	4.4% - 4.8%
Real GDP Growth	3.24%	2.5% - 2.9%

(*Id.*)

99. In addition, interest rates, as represented by U.S. Treasury yields, have been very low, reflecting in part the currency and economic crisis in Europe and the Federal Reserve Bank's monetary policy to stimulate the U.S. economy (i.e., buying U.S. Treasury securities and increasing monetary supply). (*Id.*)

100. Although Staff generally uses six different ROE estimation methodologies, Staff restricted its analysis to those methodologies employed by SWG plus the ECAPM analysis, and applied these methodologies to SWG's Proxy Group. (*Id.* at 10.) Staff performed a limited analysis in order to clearly highlight the reasons for the different ROE determinations by Staff and SWG because, generally, different ROE determinations result from the use of different estimation methods, proxy groups, and other data. (*Id.* at 8, 10.) The results of Staff's analyses are summarized in the table below:

Methodology	Range	Average
Constant Growth DCF	8.69% to 9.45%	9.04%
Three-Stage DCF	8.53% to 9.33%	8.93%
CAPM & ECAPM	7.85% to 8.26%	8.06%
Bond Yield Plus Risk Premium	9.37%	9.37%
Average		8.85%
Average Excluding CAPM & ECAPM		9.11%
Staff's Recommendation	**8.70% to 9.50%**	**9.10%**

(*Id.* at 3.)

101. In contrast to SWG's DCF analyses, Staff's analyses (a) updated the stock data through the first quarter of 2012, (b) did not use the retention growth estimate technique, and (c) applied a different third-stage dividend growth estimate for the three-stage method. (*Id.* at 11-12, 14.) Staff states that it did not consider the retention growth estimate technique because although SWG utilized this technique in this proceeding, SWG's expert argued against application of the technique in Nevada Power Company d/b/a NV Energy's ("Nevada Power")

2011 general rate case, and SWG has failed to explain its inconsistent application of the technique. (*Id.* at 12.) Staff notes that applying the retention growth technique increases the average as follows:

DCF Method	Including Retention		Excluding Retention	
	Range	Average	Range	Average
Constant	8.69% to 10.01%	9.28%	8.69% to 9.45%	9.04%
Three-Stage	8.61% to 9.41%	9.01%	8.53% to 9.33%	8.93%

(*Id.* at 13.)

102. Staff asserts that SWG's third-stage dividend growth rate of 5.78 percent is overstated and recommends 4.45 percent. (*Id.* at 14-16.) Staff states that the Energy Information Administration's ("EIA") "Annual Energy Outlook 2012" issue indicates economic growth is forecasted to be slower than historical economic growth. (*Id.* at 15.) The EIA economic growth forecast is based upon a review of several other forecasts.[13] (*Id.*) While the historical economic growth (1926 to 2011) averaged 3.24 percent, EIA forecasts a 2.55 percent growth rate as measured by the GDP. (*Id.* at 16.) Further, Staff contends SWG used a consumer price index ("CPI") measure (Treasury Inflation Protected Securities) to estimate the inflationary change in the GDP. (*Id.*) Staff recommends using the EIA's forecasted GDP price index rate of 1.9 percent, as published in "Annual Energy Outlook 2012," rather than SWG's 2.2 percent. (*Id.* at 14-16; Exhibit 29, Att. YO-5 at 12, 16-18.)

103. Staff's CAPM analysis uses a different risk-free rate and market risk premium than SWG's. (Exhibit 29 at 18-19.) Staff asserts that the risk-free rate should be the historical average 20-year U.S. Treasury Bond yield (1926—first quarter 2012) not the forecasted 30-year U.S. Treasury Bond yield. (Exhibit 29 at 18; Exhibit 29, Att. YO-10 at 13.) Using a 30-year U.S. Treasury Bond yield will increase the risk-free rate by 20 to 30 basis points. (Tr. at 241.)

[13]For example, HIS Insight Global (November 2011), Social Security Administration (August 2011), and Blue Chip Consensus (October 2011).

Staff argues SWG's derived market risk premiums are inappropriate for analytical purposes because the calculated market risk premiums significantly exceed published estimates.[14] (Exhibit 29 at 17-23.) Staff recommends a 6.6 percent market risk premium, which is the observed average for the period 1926 to 2011. (*Id.*) Staff acknowledges its market risk premium exceeds the rates cited in published reports (5.5 percent, 5.5 percent, and 4.48 percent) which reflect forecasted low inflation and low economic growth. (*Id.*) However, Staff asserts its market risk premium rate range is more conservative than SWG's 8.6 to 10.4 percent range. (Exhibit 29 at 17-23; Exhibit 29, Att. YO-9 at 3, Att. YO-10 at 10-11, Att. YO-11 at 4, 6.)

104. Additionally, Staff's recommendation incorporates the ECAPM technique. Staff asserts that the ECAPM is a common methodology and easy to employ, as it only requires a minor modification to the CAPM equation. (Exhibit 29 at 23-24.) Staff calculated the ECAPM using a standard value of 25 percent for the direct assignment of the market risk premium to SWG. (*Id.* at 24.)

105. Staff recommends modifying SWG's risk premium methodology to reflect the current forecasted 30-year U.S. Treasury Bond yield (replace SWG's 3.5 percent with 3.0 percent) and replace the long-linear regression formula with a linear regression formula. (Exhibit 29 at 26.) Staff asserts that the linear regression derived formula, which measures the difference between authorized ROEs and the U.S. 30-year Bond yields, is statistically more accurate. (*Id.* at 26-27.)

SWG's Rebuttal Position

106. In its rebuttal testimony, SWG recommends reducing its proposed ROE to 10.50 percent in order to account for the stabilization of market conditions that has occurred since

[14] Staff reviewed documents include "Market Risk Premium Used in 82 Countries in 2012: a Survey with 7,192 Answers" by IESE (5.5 percent); Duff & Phelps' "Risk Premium Report 2012" (5.5 percent); and "The Equity Risk Premium in 2012" by John R. Graham and Campbell R. Harvey (4.48 percent). (Exhibit 29 at 22-23.)

SWG filed its direct testimony. (Exhibit 33 at 11.) SWG revised its analysis to include information through July 31, 2012 and the ECAPM technique, but states that its reasonable ROE range is still 10 to 10.75 percent. (*Id.* at 13-14.) Additionally, SWG concurs with Staff that no adjustment for the GIR is warranted. (*Id.* at 47.)

107. SWG's updated analysis had a minor effect upon the original results. (*Id.* at 14.) Under the DCF analysis, both the low and mean growth estimates increased slightly (ranging from 0.2 to 0.18 percent) and the high growth estimate decreased slightly (ranging from 0.0 to 0.28 percent). (*Id.*) SWG notes that two of the three CAPM analyses showed reductions while the third analysis showed an increase. (*Id.* at 14-15.) The ECAPM results are slightly below the initial CAPM results. (*Id.* at 15.) The risk premium methodology declined slightly by 0.05 percent. (*Id.*; Exhibit 33 at Att. RBH-R-1, Att. RBH-R-3, Att. RBH-R-6.) SWG estimated that using Staff's historical 3.24 percent real GDP growth rate decreased the multi-stage DCF mean from a high growth rate range of 9.53 to 10.85 percent down to 8.95 to 10.31 percent. (Exhibit 33 at Att. RBH-R-3; Exhibit 106.)

108. SWG asserts that the following are shortcomings of BCP's DCF analyses:

a. SWG contends that BCP's focus upon the Federal Reserve target federal funds rate is misplaced. (Exhibit 33 at 49.) The federal funds rate, is an overnight interest rate and is not necessarily relevant in determining the appropriate ROE. (*Id.*)
b. SWG further asserts that BCP's DCF analysis is flawed. (*Id.* at 51.) BCP's constant growth DCF relied upon historical inputs in developing the retention growth rate rather than forecasted information. (*Id.*)
c. BCP's multiple-stage DCF uses an implied constant dividend growth rate rather than movement toward an industry average, which Value Line estimates to be 65 percent for a natural gas distribution industry. (*Id.* at 52-54.)
d. BCP's multiple-stage DCF analysis assumed that dividends are paid annually at the end of the year rather than quarterly. (*Id.* at 52, 54-55.) SWG states that simply increasing the dividend payment to semi-annually increases BCP's DCF results as follows:

	Mean	Median	Proxy Group Company Range
BCP	9.08%	9.04%	8.76% - 9.80%
SWG Revised BCP	9.25%	9.21%	8.92% - 10.02%

(*Id.* at 52, 54-55, Att. RBH-R-14.)

109. With respect to BCP's CAPM analysis, SWG asserts that it is flawed because it relied upon a historic market risk premium, and BCP's calculation is incorrect. SWG states that if the market risk premium is limited to the income-only component, it would increase to 6.60 percent, which increases the CAPM and ECAPM analyses as follows:

	CAPM		ECAPM	
	Mean	Median	Mean	Median
BCP	8.70%	8.66%	9.12%	9.04%
SWG Revised BCP	9.02%	8.98%	9.46%	9.38%

(*Id.* at 56-57, Att. RBH-R-15.)

110. Additionally, SWG asserts that BCP's financial ratio analysis is flawed. (Exhibit 32 at 9-11.) BCP failed to consider the deferred energy accounting interest expense, credit rating balance sheet adjustments, and presumes the ROE will be earned. (*Id.*) Further, BCP failed to consider the impact upon the credit rating agency's regulation perspective. (*Id.* at 7.)

111. With respect to Staff, SWG asserts that:

a. Staff's constant DCF analysis was developed using mismatched inputs and inappropriately excluded the retention growth technique. (*Id.* at 18, 22.)
b. Using the U.S. Treasury inflation protection securities as an inflation component of the multi-stage DCF growth rate is appropriate because such securities represent the investors' collective views regarding long-run inflation expectations. (Exhibit 33 at 29.)

112. SWG asserts that its CAPM analysis which relies upon 30-year Treasury Bonds as the risk-free rate of return is more appropriate than Staff's analysis which uses a historical market risk premium and 20-year Treasury Bonds. (*Id.* at 31-32.) This is because 30-year Treasury bonds are closer to the duration in which an equity investment is held. (*Id.* at 32.)

SWG also notes that 30-year Treasury bonds generally exceed the 20-year bonds by 55 basis points. (*Id.* at 31.)

113. SWG further asserts that Staff's criticism of SWG's market risk premiums is unfounded. (*Id.* at 42.) SWG states that using a DCF analysis to derive the market risk premium is a published methodology. (*Id.* at 35, 43-44.) Investors consider market volatility in their analysis and, therefore, adjusting historical market risk premium for increased volatility is reasonable. (*Id.* at 35-38.)

114. SWG recommends denying BCP's 25 basis point adjustment to the ROE for decoupling. (*Id.* at 58.) SWG asserts that BCP failed to address the relevant question of whether SWG is less risky in comparison to the Proxy Group—not whether it is risky with or without its rate design proposals. (*Id.*) SWG states that its risk profile is comparable to the Proxy Group. (*Id.* at 59-60, Att. RBH-R-16.)

ii. Rehearing (January 10-11, 2013)

SWG's Position

115. SWG states that if the Commission accepts SWG's corporate capital structure, then SWG recommends a ROE range of 10.0 percent to 10.75 percent, and requests a ROE of 10.65 percent within that range. (Tr. at 1379.)

116. SWG states that if the Commission affirms the capital structures set forth in the Modified Final Order, then the authorized ROEs for the NND and SND are too low because they inadequately address the leverage differential between the authorized capital structure and the Proxy Group capital structure. (Tr. at 1376-77.) SWG recommends a ROE range of 9.50 percent to 10.40 percent for the NND, and a ROE range of 10.50 percent to 11.40 percent for the SND. (Exhibit 128 at 1; Tr. at 1379.)

117. SWG states that if the NND and SND are to have separate capital structures, the Proxy Group capital structure in the Modified Final Order is inaccurate. (Tr. at 1298.) Specifically, SWG states that a weighted Proxy Group average rather than a simple Proxy Group average was developed. SWG asserts that a weighted average inappropriately provides weight to one large Proxy company. (Tr. at 1298, 1357.)

118. In addition, SWG states that the Commission's Order, which includes total capital rather than permanent capital, should have excluded short-term debt. (Tr. at 1298-99.) SWG asserts that only permanent capital (long-term capital) that finances rate base should be used. (Tr. at 1299.) Moreover, SWG states that it is inappropriate to use a single point in time—in this instance, December 31, 2011—to estimate the Proxy Group debt. SWG asserts that a multi-year average (i.e., three to five years) should have been used to mitigate any year-to-year financial variations, and variations in short-term debt due to seasonal cash flow needs. (Tr. at 1300, 1372-73, 1397.)

119. SWG testifies that the Proxy Group's five-year quarterly average total debt leverage ratio of 50.11 percent is consistent with the debt ratios implied by the median of the state commissions' authorized 2012 equity ratios for the periods January-July 2012 and August-December 2012. (Exhibit 21, Att. TKW-5 at 1; Exhibit 126; Exhibit 128 at 3-5; Tr. at 1372-73.)

120. SWG acknowledges that the Commission considered in its ROE decision the difference in leverage between the authorized capital structures and the Proxy Group. (Tr. at 1370, 1396-97.) For the SND, SWG estimates that the Commission increased the ROE by 10.3 basis points for each one percent increase in leverage relative to the Proxy Group capital structure set forth in the Modified Final Order. However, the Commission reduced the NND

ROE by 1.7 basis points for each one percent decrease in leverage relative to the Proxy Group.[15] (Exhibit 128 at 2; Tr. at 1368-71.)

121. SWG states that it based its newly proposed reasonable range of ROEs for the separate capital structures upon its own analysis of the Commission's Order regarding the ROE basis point leverage adjustment to various ROEs compared with the Proxy Group capital structure having a debt ratio of 50.11 percent. (Exhibit 128; Tr. at 1373-76.) The table below summarizes this analysis, with the baseline being the Modified Final Order, and includes the Proxy Group's December 31, 2011 capital structure:

ROE Median or Mid-point Used	ROE	NND	SND
Modified Final Order	9.55%	9.20%	9.85%
5-Year Quarterly Total Debt			
Modified Final Order Mid-Point	9.55%	9.28%	10.30%
January – July 2012 Median Authorized ROE	9.75%	10.50%	9.48%
August – December 2012 Median Authorized ROE	10.12%	10.87%	9.85%
SWG Recommended	10.65%	11.40%	10.38%

(Exhibit 126; Exhibit 128; Tr. at 1371.) SWG states that its proposed reasonable range of ROEs is based on a consolidated ROE range of 9.75 percent to 10.65 percent. (Exhibit 128 at 1; Tr. at 1377.)

122. SWG contends that the authorized equity ratio of 45.4 percent in the Commission's Modified Final Order is less than the median 51 percent equity ratio authorized in 2012 by other commissions as illustrated below.

	Median Equity Ratio	Median ROE
January - July 2012	50.82%	9.73%

[15] The increase and decrease in ROE was calculated by dividing the difference between the authorized ROE and the mid-point of the Commission's ROE range of 9.1 percent to 10.0 percent (i.e., 9.55 percent) by the difference between the NND's and SND's authorized capital structures debt percentage and the estimated capital structure for the Proxy Group (*see* Modified Final Order at paragraph 69) on December 31, 2011, which equals 54.49 percent debt and 45.51 percent equity. (Exhibit 128 at 2; Tr. at 1369.)

August – December 2012	51.65%	10.10%
	Nevada Consolidated	**Mid-Point**
PUCN	45.41%	9.55%

(Exhibit 126; Tr. at 1353-54, 1361-63.)

123. SWG asserts that equity markets reacted negatively to the Commission's decision indicating that the ROEs are too low. (Tr. at 1363.) SWG provided a statistical analysis of SWG's cumulative stock market returns compared to the Proxy Group cumulative returns for two months prior to the issuance of the Commission's Order and two months subsequent to the Commission's Order. (Tr. at 1363-66.) Prior to the issuance of the Order, SWG's total return was 2.87 percent while the Proxy Group's total return was 2.65 percent. (Exhibit 127; Tr. at 1364.) SWG asserts that following the issuance of the Order SWG significantly underperformed. (Tr. at 1364.) SWG's rate of return was a negative 3.53 percent while the Proxy Group return was a positive 0.25 percent. (Exhibit 127; Tr. at 1364.) According to SWG, this indicates a statistically significant relationship between the date of the Order and SWG's stock performance. (Tr. at 1365, 1395.)

124. SWG further contends that the financial community was aware of the capital structure issues. (Tr. at 1367.) In support, SWG references the UBS Report and the transcript from SWG's third quarter earnings conference. (Tr. at 1366.)

BCP's Position

125. BCP asserts that the Commission addressed the additional risk associated with the SND being more leveraged than the Proxy Group. (Tr. at 1417.) BCP testifies that the financial community generally expects a 10 basis point change for a one percent change in debt leverage. (Tr. at 1418.) BCP's 10 basis point estimate is based on several studies that were performed

between 1958 and 1987. (Exhibit 131; Tr. at 1418, 1439.) These studies support the range of 7.6 to 13.8 basis points per one percent change in leverage, with 10 basis points being approximately the mid-point.[16] (Tr. at 1439-40.)

Study Year	Empirical Study	Theoretical Study
1958	115	
1963	62	
1968		34
1973		75
1974		45
1977	237	
1980		109
1986		72
1987		117
Average	138	76

(Exhibit 131 at 3.)

126. The financial text also notes that a controversy exists if the relationship is linear or curvilinear. (*Id.* at 2-3.)

127. BCP further testifies that utility commissions typically consider various issues, including capital structures, in determining the appropriate authorized ROE selected from the range of reasonable ROEs. (Tr. at 1441-42.)

128. BCP testifies that it has not seen any financial reports indicating the financial community is "alarmed with the regulatory process or regulatory decisions" for SWG or any other utility regulated by the Nevada Commission. (Tr. at 1414.) BCP states that the UBS Report mentions the Commission's decision, but mere mention of the decision does not constitute alarm. BCP states that it is common for financial reports to report recent rate case decisions (e.g., amount of requested granted, authorized ROE, equity ratio, or hot button issues).

[16] The basis points expressed in the table are for the entire 10 percent change in leverage studied (i.e., 40 percent to 50 percent). The range was divided by 10 to arrive at the basis points per 1 percent in leverage. (Exhibit 131 at 3.)

(*Id.*)

129. BCP asserts that, in this particular case, whether a quarterly average or one point in time method is used in the Proxy Group to address short-term debt seasonality should not be a major concern. (Tr. at 1459-60.) Nonetheless, BCP states that it is better when comparing SWG and the Proxy Group to analyze the same data either at one point in time or over an average period of time. (Tr. at 1460.)

Staff's Position

130. Staff asserts that the Modified Final Order's range of reasonable ROEs of 9.10 percent to 10.0 percent is still appropriate. (Tr. at 1535-36.) The range is based upon the fully vetted testimony provided in this proceeding. (Tr. at 1536.)

131. Staff recommends a ROE of 9.85 for the SND and 9.30 percent for the NND. (Exhibit 135 at 3, 7; Tr. at 1492, 1495.) Staff states that its recommended ROE for the NND reflects Staff's recommended capital structure in the NND, which is slightly more leveraged than the 34.36 percent debt in the Modified Final Order. (Tr. at 1495.)

132. Staff argues that SWG's pre- and post-draft Order stock market price analysis is too simplistic. (Tr. at 1499.) Staff argues that the change in total market return referenced by SWG was caused by macroeconomic issues, industry-specific issues, and SWG's third quarter earnings report. SWG's third quarter earnings report is important to investors as it indicates how the utility is performing. (Tr. at 1498-99.) For instance, a comparison of NiSource's (a Proxy utility) stock price to SWG's stock price illustrates a similar pattern in the market return for NiSource prior to and after the issuance of the Order. (*Id.*; Exhibit 137.)

133. In responding to SWG's criticisms of the Modified Final Order's assessment of the Proxy Group's capital structures, Staff notes that a simple average based on a Proxy Group's

corporate capital structure differentiates for a company's size by not giving more weight to larger companies. (Tr. at 1521.) In addition, Staff states that short-term debt should be included in the assessment because it is a form of debt financing. (Tr. at 1522.) Customer deposits are likely considered short-term debt because the funds are generally held for less than a year. (Tr. at 1475.)

134. Staff also asserts that it is preferable to maintain consistency between the measurement of the capital structure for SWG and the Proxy Group. (Tr. at 1529.) Staff states that, on this record, SWG has only provided its information for one point in time and not the five-year quarterly average SWG used for its Proxy Group. (Tr. at 1530.) Staff also states that the rate base component of cash working capital should be considered a short-term investment. (Tr. at 1474-75.)

SWG's Rebuttal Position

135. SWG continues to recommend using the five-year quarterly average Proxy Group capital structure compared to SWG at one point in time as a benchmark. (Tr. at 1553, 1555, 1567-68.) According to SWG, the five-year quarterly average mitigates variations in financial performance and addresses the issue of short-term debt seasonality. (Tr. at 1553, 1567.) SWG contends that the Proxy Group's five-year quarterly average capital structure, with an equity ratio of 49.64 percent[17] is consistent with both the estimated June 30, 2012[18] Proxy Group equity ratio of 50.3 percent and the January 2012 through July 2012 average authorized equity ratio of 50.8 percent. (Exhibit 126; Exhibit 139; Tr. at 1555-56.)

[17] SWG calculated for the proxy group, using a five-year quarterly average, a debt ratio of 50.11 percent; common equity of 49.64 percent and preferred stock of 0.25 percent. (Exhibit 21, Att. TKW-5 at 1.) In including short-term debt, SWG states the proxy group capital structure includes 50.11 percent debt. By default, SWG presumes the remaining 49.89 percent common equity for it does not have any preferred stock. (Exhibit 5, Vol. 1, Statement F at 1, 3; Exhibit 5, Vol. 2, Statement F at 1, 3; Exhibit 21, Att. TKW-5 at 1; Exhibit 128 at 3-6.)

[18] June 30th was selected for the proxy group as it was the closest reporting period to the certification end date of May 31, 2012. (Tr. at 1566-67.)