BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

FILED
09-26-11
04:59 PM

Application of Southern California Edison Company (U338E) for Authority to, Among Other Things, Increase Its Authorized Revenues for Electric Service In 2012, And to Reflect that Increase in Rates.	Application 10-11-015 (Filed November 23, 2010)

OPENING BRIEF
OF THE DIVISION OF RATEPAYER ADVOCATES

LAURA TUDISCO
NOEL OBIORA
NICHOLAS SHER
TRACI BONE

Attorneys for the Division of Ratepayer Advocates

California Public Utilities Commission
505 Van Ness Ave.
San Francisco, CA 94102
Phone: (415) 703-2164
Email: ljt@cpuc.ca.gov

September 26, 2011

462144

TABLE OF CONTENTS

Page

1. Introduction & Summary of Recommendations 1
2. Policy 2
   - 2.1. Impact on SCE's Customers 2
   - 2.2. Impact on State and Local Economy 5
   - 2.3. SCE's Threats of Layoffs 7
   - 2.4. Summary of Recommendations 8
   - 2.5. Procedural Background 10
   - 2.6. Forecasting Issues 11
     - 2.6.1. Overview 11
     - 2.6.2. Capital Expenditures Versus Capital Additions 12
3. Evidentiary Standards and Burden of Proof 13
4. Generation 15
   - 4.1. Generation – Nuclear Generation 15
     - 4.1.1. SONGS 15
       - 4.1.1.1. SDG&E's Request for SONGS Cost Recovery 16
       - 4.1.1.2. SONGS O&M - SCE's Proposal for Ratepayers To "Share" SONGS Cost Savings With SCE Shareholders 16
       - 4.1.1.3. Background 16
       - 4.1.1.4. SCE Has An Obligation To Prudently Manage SONGS 18
       - 4.1.1.5. SCE's High Pressure Turbine Retrofit Project 21
       - 4.1.1.6. Parking Lot Lighting Project 24
       - 4.1.1.7. Service Air Piping Project 25
       - 4.1.1.8. Cafeteria Remodeling Projects 25
     - 4.1.2. Palo Verde 27
   - 4.2. Generation – Coal Generation 29
     - 4.2.1. Mohave 30
     - 4.2.2. Four Corners 30
   - 4.3. Generation – Hydroelectric Generation 31
   - 4.4. Generation – Gas-Fired Generation 32
     - 4.4.1. Mountainview 33
     - 4.4.2. Peakers 34
       - 4.4.2.1. Peakers O&M 34

4.4.2.2. Peakers Capital Expenses 34
4.5. Generation – Project Development Division 35
4.6. Generation – Other 35
4.6.1. Solar PV 35
4.6.2. Catalina Diesel 37
4.6.2.1. Catalina O&M Expenses 37
4.6.2.2. Catalina Capital Expenditures 38
4.6.3. Fuel Cells 39
5. Transmission and Distribution 39
5.1. T&D -- Policy 39
5.2. T&D – Advanced Technology 44
5.2.1. Circuit Automation 56
5.2.2. Smart Distribution Transformers 56
5.2.3. Distribution Efficiency Enhancement Project 57
5.2.4. Integrated Smart Distribution 58
5.2.5. Substation Automation 59
5.2.6. Distribution Management System 60
5.2.7. Outage Information 61
5.2.8. Phasor Measurement & Wide Area Situational Awareness 62
5.2.9. Centralized Remedial Action Schemes (C-RAS) 63
5.2.10. Smart Grid Cyber Security 64
5.2.11. Advanced Technology Laboratories 65
5.3. T&D – Electric System Planning 65
5.4. T&D – Load Growth 71
5.4.1. Subtransmission Lines Plan 71
5.4.2. Distribution Substation Plan (DSP) 75
5.4.3. Substation Equipment Replacement Program (SERP) 78
5.4.4. Plug-In Electric Vehicle Readiness Program 81
5.5. T&D – Infrastructure Replacement 84
5.5.1. Cable Replacement Program 84
5.5.2. Cable in Conduit (CIC) Replacement 91
5.5.3. A and B Bank Transformers 95
5.5.4. Distribution Circuit Breakers 98
5.5.5. 4 kV Cutovers 101
5.5.6. 4 kV Substation Elimination 104
5.6. T&D – Engineering Design And Project Management, ... 109

5.7. T&D – Customer-Driven Programs 112
5.7.1. Rule 20A Conversions 113
5.7.2. Rule 20B and 20C Conversions 116
5.8. T&D – Inspection and Maintenance 120
5.8.1. Overview of SCE's Request 130
5.8.2. Capital Preventive Maintenance 131
5.8.2.1. Asset Based Preventive Maintenance 131
5.8.2.2. Transformer Bank Replacement 132
5.8.2.3. Underground Structures 133
5.8.3. Wood Pole Replacement 134
5.8.4. Joint Pole Credits 136
5.8.5. Wood Pole Disposal 136
5.8.6. Removal of Idle Facilities 137
5.9. T&D - Distribution Planning and Field Accounting 137
5.10. T&D - Grid Operations 140
5.10.1. Overview 149
5.10.2. Street Light Replacement Program 149
5.11. T&D – Distribution Construction and Maintenance 150
5.11.1. Overview 158
5.11.2. Breakdown Maintenance 159
5.11.3. Tools and Work Equipment 160
5.12. T&D – Substation Construction and Maintenance 161
5.12.1. Substation Capitalized Maintenance 170
5.12.2. Substation Rule 20 171
5.12.3. Substation Added Facilities 171
5.13. T&D – Transmission 172
5.13.1. Transmission Deteriorated Poles 183
5.14. T&D – Business Process and Technology Integration 184
5.15. T&D – Technical Services 190
5.16. T&D – Business, Regulatory and Financial Planning 198
5.17. T&D – Other Costs and OOR 202
5.17.1. Other Costs - 560.281, 568.281, 588.281, 580.282 & 590.281 202
5.17.2. OTHER OPERATING REVENUES 451.100 & 456.308 208
5.18. T & D -- NERC/CIP-Related Costs 210
6. Customer Service 216

6.1. Customer Service Expenses – Integration of Edison SmartConnect Costs and Benefits 216
6.2. Customer Service Expenses – Operations 217
6.2.1. FERC Account 901 – Business Unit Management and Support 217
6.2.2. FERC Account 902 – Meter Reading Expenses 224
6.2.2.1. FERC Sub-Account 902.300 – Operations Center 225
6.2.3. FERC Account 903 – Customer Records and Collections 227
6.2.3.1. FERC Sub-Account 903.200 – Credit 227
6.2.3.2. FERC Sub-Account 903.500 – Billing 232
6.2.3.3. FERC Sub-Account 903.800 – Customer Communication Organization 236
6.2.4. FERC Account 905 – Miscellaneous Expenses 239
6.2.4.1. FERC Sub-Account 905.300 – Policy Adjustments 240
6.2.4.2. FERC Sub-Account 905.800 – Consumer Affairs 241
6.2.4.3. FERC Sub-Account 905.900 – Market Research & Communications 241
6.2.5. FERC Account 586 – Meter Expense 246
6.2.5.1. FERC Sub-Account 586.400 – Test and Inspect Meters 246
6.2.6. FERC Account 587 – Customer Installation Expense 248
6.2.6.1. FERC Sub-Account 587.200 – Energy Theft 248
6.3. Customer Service Expenses – Information Delivery 249
6.3.1. FERC Sub-Account 908.600 Customer Care – Account Management 249
6.3.2. FERC Sub-Account 908.610 – Customer Care – Energy Centers 250
6.3.3. FERC Sub-Account 908.640 – Customer Care – Account Management 253
6.3.4. FERC Sub-Account 916.600 – Customer Care – Program Management/ Rate Communications 256
6.3.5. FERC Account 920 – Local Public Affairs 257
6.4. Customer Service Expenses – Service Fees 258
6.5. Customer Service Expenses – Other Operating Revenue 258
6.6. Customer Service Capital – Structures and Improvements 260
6.7. Customer Service Capital – Furniture and Equipment 261
6.8. Customer Service Capital – Specialized Equipment 261
6.9. Customer Service Capital – Meters and Advanced Metering 261

6.10. Customer Service Capital – Capitalized Software Projects 264
6.10.1. Alerts and Notification 265
6.10.2. Dynamic Pricing Project 267
6.10.3. Home Area Network and Troubleshooting Project 267
6.10.4. Plug In Vehicles Support Systems 268
7. Information Technology and Business Integration 268
7.1. Application Services 272
7.2. Technology and Risk Management 273
7.3. Information Technology Expenses – Infrastructure Operations 274
7.4. Information Technology Expense -Business Operations Management 275
7.5. Information Technology –Capital Expenditures 276
7.6. Information Technology – MRTU 276
7.7. Information Technology Capital – Capitalized Software 277
7.8. Other Capitalized Software 277
8. Human Resources, Benefits and Other Compensation 278
8.1. Human Resources Department Expenses 278
8.1.1. Executive Officers Compensation 279
8.1.2. Executive Officers Non-Labor Expense 280
8.2. Human Resources Capitalized Software 280
8.3. Results Sharing 281
8.4. Spot Bonuses 282
8.5. Executive Compensation 285
8.5.1. Overall Compensation Levels 285
8.5.2. Short Term Incentives 288
8.5.2.1. Executive Incentive Compensation 292
8.5.3. Stock Options and Other Long-Term Incentive Programs 292
8.6. Pensions and Benefits 293
8.6.1. Pensions 294
8.6.2. PBOPs 299
8.6.3. Other Benefits 299
8.6.3.1. 401 (k) Savings Plan 299
8.6.3.2. Medical Programs 301
8.6.3.3. Disability Program 303
8.6.3.4. Group Life 304
8.6.3.5. Miscellaneous Benefits – Preventive Health and Work/ Life Programs 305

8.6.3.6. Executive Benefits 306
9. Administrative and General 310
9.1. Financial Organizations 310
9.1.1. Controller's Organization 310
9.1.1.1. Controller's Organization Account 920/ 921 310
9.1.1.2. Controller's Organization Account 923 312
9.1.1.3. Controller's Organization Account 926 312
9.1.1.4. Controller's Organization – Capitalized Software 312
9.1.2. Audit Services 313
9.1.2.1. Audit Services Account 920 313
9.1.2.2. Audit Services Account 921 314
9.1.3. Treasurer's Department 315
9.1.3.1. Treasurer's Department Account 920 315
9.1.3.2. Treasurer's Department Account 921 316
9.1.3.3. Treasurer's Department Account 930 316
9.1.4. Tax Department 317
9.1.4.1. Tax Department Account 920 317
9.2. Risk Control 319
9.2.1. Risk Control Group Account 920 319
9.2.2. Risk Control Group Account 921 319
9.3. Law Department 320
9.3.1. In –House Resources 320
9.3.2. Outside Counsel (duplicate) 322
9.3.3. Corporate Governance Account 930 324
9.3.4. Capital Project: Electronic Discovery 325
9.4. Claims 326
9.4.1. Account 925: Injuries and Damages – Claims 326
9.4.2. Account 925: Injuries and Damages – Claims Reserve 326
9.5. Workers' Compensation 327
9.5.1. Workers Compensation Account 925 Staff 328
9.5.2. Workers Compensation Account 925 Reserves 328
9.6. Ethics and Compliance 329
9.6.1. Ethics and Compliance Account 920/921 332
9.6.2. Ethics and Compliance Account 923 333
9.7. Regulatory Policy and Affairs 333
9.7.1. RP&A – Labor Expenses 334

9.7.1.1. Affiliate Transaction Rules Compliance 334
9.7.2. R&A Labor Forecast 336
9.8. NERC/CIP-Related Costs 337
9.9. Corporate Membership Dues and Fees 338
9.10. Corporate Communications 338
9.10.1. Corporate Communications Account 920 338
9.10.2. Corporate Communications Account 921 338
9.11. Property and Liability Insurance 339
10. Power Procurement 340
10.1. Market Strategy and Resource Planning Department 341
10.2. Energy Supply and Management Department 345
10.3. Renewable and Alternative Power Department 347
10.4. Power Procurement and Finance Department 349
11. Operations Support 350
11.1. Corporate Environment, Health and Safety 351
11.1.1. FERC Accounts 920/921 – Corporate Environment, Health & Safety 351
11.1.2. FERC Account 923 – Corporate Environment, Health & Safety 355
11.1.3. FERC Account 925 – Corporate Environment, Health & Safety 356
11.2. Corporate Resources 357
11.2.1. FERC Accounts 920/921 – Corporate Resources 358
11.2.2. FERC Account 931 – Rents 360
11.2.3. Corporate Resources Additional Facilities – Capital Expenditures 362
11.2.3.1. Alhambra Data Center – Capital Expenditures 364
11.2.3.2. Customer Energy Center – Capital Expenditures 365
11.2.3.3. Service Center Modernization – Capital Expenditures 365
11.2.3.4. Energy Efficiency – Capital Expenditures 366
11.3. Corporate Security 367
11.3.1. FERC Accounts 920/ 921 – Corporate Security 367
11.3.2. Critical Infrastructure Protection Physical Security Project – Capital Expenditures 369
11.4. Transportation Services 370

11.4.1. Transportation Services Department -- Operations and Maintenance Expenses 370
11.4.2. Transportation Services Department – Capital Expenditures 371
11.5. Supplier Diversity 372
11.5.1. FERC Accounts 920/ 921 372
11.6. Operations Support Services 373
12. Ratemaking 375
13. Sales and Customers 376
13.1. Overview 376
13.2. Economic / Demographic Conditions 376
13.3. Sales 378
13.3.1. Residential Sales 378
13.3.2. Commercial Sales 379
13.3.3. Industrial Sales 380
13.3.4. Other Public Authority Sales 381
13.3.5. Agricultural Sales 382
13.4. Customer Growth Rates 383
13.4.1. Residential Customers 383
13.4.2. Commercial Customers 384
13.4.3. Industrial Customers 385
13.4.4. Other Public Authority 386
13.4.5. Agricultural Customers 386
13.5. New Meter Connections 387
13.5.1. Residential 387
13.5.2. Non-Residential 387
14. Cost Escalation 388
14.1. SCE Methodology 388
14.2. DRA's Methodology 389
15. Other Operating Revenue 391
16. Post Test Year Ratemaking 391
16.1. Overview 391
16.2. SCE's Post Test Year Ratemaking Proposals 392
16.2.1. SCE's Proposed Revenue Increases for Expenses, Capital Expenditures and Nuclear Refueling 393
16.2.1.1. Annual Advice Letters 393
16.2.1.2. O&M Expense Escalation 393

16.2.1.3. Capital-Related Cost Increases 394
16.2.1.4. SmartConnect 394
16.2.1.5. Nuclear Refueling Outages 394
16.2.1.6. Treatment of Major Exogenous Cost Changes 395
16.2.2. SCE's Other Post-Test Year Ratemaking Requests 395
16.2.2.1. Application Requirement for Post-Test Year Ratemaking 395
16.2.2.2. SCE's Claim of Error Regarding Construction Work in Progress in the TY 2009 Decision 396
16.2.2.3. SCE's Claim of Error Regarding Other Operating Revenues in the TY 2009 Decision 396
16.3. DRA's Recommendations 397
16.3.1. Components of DRA's Primary Recommendation for a PTYR Mechanism 397
16.3.1.1. DRA's PTYR Mechanism Increases Base Revenues by the Consumer Price Index 398
16.3.1.2. A PTYR Mechanism Based on CPI Gives SCE a Needed Incentive to Manage Costs 400
16.3.2. DRA Recommendations on Other SCE Proposals 400
16.3.2.1. Annual Advice Letters 401
16.3.2.2. SmartConnect 401
16.3.2.3. Nuclear Refueling Outages 402
16.3.2.4. Treatment of Major Exogenous Cost Changes 402
16.3.2.5. Application Should Not Be Required to Implement PTYR 403
16.3.2.6. SCE's Claim of Error for "Stranded Construction Work In Progress" 404
16.3.2.7. Budget Based Capital Additions 404
16.3.2.8. Separate Escalation of Other Operating Revenues 404
16.3.3. DRA's Alternate Recommendation for a PTYR Mechanism 405
16.3.3.1. PTYR Capital-Related Adjustments 405
16.3.3.2. PTYR Expense-Related Adjustments 406
17. Productivity 409
18. Electric Plant 410
19. Taxes 410
19.1. Meals and Entertainment Expenditures 410
19.2. Research and Development Tax Credits 412

20. Rate Base 414
20.1. Customer Advances 414
20.1.1. Electric Construction 414
20.1.2. Temporary Services 415
20.2. Materials and Supplies 415
20.2.1. Transmission and Distribution 415
20.2.2. Other Generation – Peaker Project 417
20.3. Working Cash 417
20.3.1. Cash Balances 417
20.3.2. Prepayments 418
20.3.3. Lead-Lag Working Capital Requirement 419
20.4. Unfunded Pension Reserves 420
20.5. Customer Deposits 421
20.6. Rate of Return on Legacy Meters and Mohave Generating Station 422
20.6.1. Background 422
20.6.2. DRA's Primary Recommendation 425
20.6.3. DRA's Alternative Recommendation 425
20.7. Rate Base Impact of Sale of Four Corners Generating Station 426
21. Non-Tariffed Products and Services 427
22. Depreciation 427
22.1. Overview 427
22.2. Recovery of Original Cost of Fixed Assets 429
22.3. Net Salvage Rates 430
22.4. Calculated and Recorded Depreciation Parameters 431
22.5. Future Cost of Removal 432
22.6. SCE's Current Net Salvage Rates As Compared to Other Utilities 434
22.7. SCE Already Collects Sufficient Revenues 435
22.8. SCE Supposed "Reserve Imbalance" 436
22.9. Third Party Reimbursements 437
22.9.1. DRA's Proposals for Third Party Reimbursements Accounting 437
22.9.2. Accounting for Third Party Reimbursements In Other Jurisdictions 442
22.9.3. SCE's "Proper" Reimbursement Accounting Error 442
23. Jurisdictional Cost Separation 443
24. Other Results of Operations Issues 443
25. Audit 443

25.1. WISER Program 444
25.2. GIS Pilot Project 444
25.3. Catalina Fire 445
25.4. Navajo Nation Royalty Litigation 446
25.5. Happy Camp Fire 448
25.6. Tax Services 448
25.7. ACE Awards 450
25.8. Allowance for Funds Used During Construction 451
25.8.1. Short-Term Debt Balances 451
25.8.2. Short-Term Debt Rates 455

TABLE OF AUTHORITIES

Page

Federal Statutes

Pub.L.107-204 116 Stat 745 315

California Statutes

Public Utilities Code §309.5 ..... passim
Public Utilities Code §399.11 ..... passim
Public Utilities Code §451 ..... passim
Public Utilities Code §454 ..... passim

CPUC Decisions

Alternate Decision of President Peevey on Test Year 2009 General Rate Case for Southern California Edison Company (2009) D.09-03-025 ..... passim

Decision Adopting Settlement Agreement (Pacificorp) (2010) D.10-09-010 388

Decision Adopting Settlement Agreement in General Rate Case of Sierra Pacific Power Company (2009) D.09-10-041.....387

Decision Adopting Test Year 2009 General Rate Increases (and Decrease) for Southwest Gas Corporation (2008) D.08-11-048 387

Decision Approving Settlement on SCE Advanced Metering Infrastructure Deployment (2008) D.08-09-039..... passim

Decision Authorizing Pacific Gas & Electric Company's General Rate Case Revenue Requirement for 2007 – 2011 (2007) D.07-03-044 387

Decision Granting in Part Petition of SCE to Modify D.07-01-039 (2010) D.10-10-016 318

Decision on Peak Day Pricing for Pacific Gas & Electric Company (2010) D.10-02-032 232

Decision on the Test Year 2008 General Rate Cases for SDG&E and SoCalGas (2008) D.08-07-046.....387

Decision Implementing Methods to Decrease the Number of Gas and
Electric Utility Service Disconnections (2010) D.10-07-048 214

Decision on Pacific Gas & Electric Company Test Year 2011
General Rate Increase Request (2011) D.11-05-018 ..... passim

Decision Regarding the Risk/ Reward Incentive Mechanism (2010)
D.10-12-049 4

In Re Southern Californian Edison Company (1996) D.96-01-011,
1996 Cal. PUC Lexis 23 426

Investigation into the Operations and Practices of SCE et al.
Regarding Utility Facilities and the Canyon Fire in Malibu in October 2007
(Filed January 2009) I.09-01-018 319

Investigation into the Practices of SCE (2008) D.08-09-038 .....16, 317

Opinion (2000) (PG&E TY 1999 GRC) D.00-02-046 11

Opinion on Southern California Edison Company's Test Year 2006
General Rate Case Increase Request (2006) D.06-05-016 11

Opinion on Base Rate Revenue Requirement and Other Phase 1 Issues
(2004) D.04-07-022 ..... passim

Order Granting Rehearing D.01-10-031, 2001 Cal LEXIS 917 *6 12

SoCal Edison Company (1980) 5 CPUC 2d 39; D.9323,
1980 Cal. PUC Lexis 1296*48 .....323, 324

Southern Counties Gas Company of California (1952) 51 CPUC 533;
D.46876.....12

Other

In the Matter of the Application of Baltimore Gas and Electric Company for Approval of
Changes in Depreciation Rates (May 4, 2010) Order No. 83310.....426

In the Matter of the Application of Washington Gas Light Company
for Approval of Changes in Depreciation Rates (February 5, 2010)
Order No. 83139 426

1. Introduction & Summary of Recommendations

Pursuant to Rule 13.11 of the Commission's Rules of Practice and Procedure (Rules), and the schedule set by Administrative Law Judge Melanie Darling, the Division of Ratepayer Advocates (DRA) submits this Brief for the General Rate Case (GRC) Application of Southern California Edison Company (SCE or Edison) for Test Year (TY) 2012.

On November 23, 2010, SCE filed Application (A.) 10-11-015 seeking revenue requirement increases for the three-year period from 2012 through 2014. On April 28, 2011, SCE submitted an "Update" to reflect effects of the Tax Relief Act and removal of nuclear seismic study and license renewal costs. From the Update, it appeared that SCE's request was for a $900 million increase[1] over its currently authorized rate level. When the additional increases SCE sought for 2013 and 2014 were added in, that brought the cumulative total increase to about $4.3 billion over current authorized revenues.[2]

In July, 2011, SCE "corrected" its testimony to say that it is asking for $794 million above revenues at present rates in 2013, followed by proposed increases of $155 million in 2013[3] and $515 million in 2014. SCE's calculation of an increase of $794 million in the test year appears to understate what the Company is really seeking, by deducting an amount for "revenues" which may or may not materialize.[4] Even using SCE's figures, however, SCE is seeking a cumulative total increase of about $4.212 ***billion*** over current authorized revenues.[5]

According to SCE's own estimates, if its Application is approved, the increase to residential rates over base rate revenues would be approximately 18.93%.[6] For a small or

---

[1] Exhibit SCE-15, Figure II-1. In Exhibit SCE-15, SCE characterizes its 2012 request as an $828 million increase over currently authorized base revenues. SCE arrives at this figure by reducing the $900 million it is actually asking for by what SCE predicts as revenue from estimated sales growth. (Application, p. 3, Table 1, lines 25 and 26.) Now, in Errata to Exhibit SCE-01, SCE characterizes its TY 2012 request as $794 million above revenues at present rates. (Ex. SCE-01, Errata, p. 1.)

[2] Ex. SCE-15, Figure II-I: ($900 M in 2012) + ($900 M + $504 M in 2013) + ($900 M + $504 M + $600 M in 2014) = $4.308 Billion over the three year GRC period.

[3] This $155 million appears to leave out the $251 million revenue requirement increase SCE will start collecting for its Smart Connect meters in 2013.

[4] Ex. SCE-15, Update, Table III-5.

[5] $866 M (in 2012) + $866 M + 251M + $256 M (in 2013) + $866M+ $251M + $256 M + $600 M (in 2014) = $4.212 Billion over the three year GRC period.

[6] 8 RT 755-756, Litzinger/SCE.

medium commercial customer, the increase would be about 15.48%.[7] With so many SCE ratepayers already struggling financially in the current economic crisis, the need for increases of this magnitude should be thoroughly scrutinized.

DRA has attempted to do so. DRA conducted its own independent analysis of SCE's various claims and forecasts and recommends that the Commission authorize SCE a CPUC jurisdiction revenue requirement of no more than approximately $5.3 billion in TY 2012 (which is roughly equal to SCE's 2012 revenues at present rates), with revenue requirement increases of no more than approximately $216 million in 2013 and $116 million in 2014, or a three-year cumulative increase of $406 million for the entire 2012 -2014 GRC period.

This Brief addresses the proposals of SCE that DRA disputes. A summary of some of the major areas of disagreement between SCE and DRA is set forth below in Section 2.4. Silence on any argument should not be interpreted as assent.

2. Policy

2.1. Impact on SCE's Customers

The Commission is charged with the responsibility of ensuring that all rates demanded or received by a public utility are just and reasonable: "no public utility shall change any rate ... except upon a showing before the Commission, and a finding by the Commission that the new rate is justified."[8] SCE's existing rates are, thus, presumed to be just and reasonable.

According to SCE's President, SCE is currently providing safe and reliable service on the rates authorized by the Commission in SCE's last GRC.[9] Why, then, SCE must receive a $794 million[10] increase to continue to provide the same level of service is up to SCE to prove. SCE has not done so.

In SCE's last GRC, the Commission authorized SCE a $4.829 billion base revenue requirement for the 2009 test year.[11] This represented a 28.8% increase over SCE's 2006 authorized revenue requirement.[12] In this GRC, SCE seeks a revenue requirement of

---

[7] Amendment to Application (11/24/2010), Table 2.

[8] Public Utilities Code §§ 451, 454.

[9] 8 RT 652, Litzinger/SCE.

[10] As noted above, DRA disputes SCE's characterization of its request being for "$794 million" but uses that figure for ease of reference.

[11] D.09-03-025, p. 2.

[12] Id.

$6.214 billion in Test Year 2012, which represents a 28% increase over SCE's 2009 authorized revenue requirement of $4.829 billion based on the purported need for many of the same projects that the Commission authorized in SCE's last GRC.

SCE's actual capital expenditures for 2009 and 2010 were $502.4 million less than SCE's forecasted capital expenditures.[13] When SCE's actual capital expenditures fall short of forecasted capital expenditures, SCE's cash flows and profits increase, for the benefit of SCE shareholders and executives, and at the expense of SCE ratepayers.

SCE's own testimony bears this out. SCE's operations, subject to rate case revenue requirement, earned 9.60% in 2009,[14] 85 basis points *above* SCE's authorized rate of return on rate base of 8.75%. For 2010, SCE estimated it would earn a return of 8.81%. In 2010, SCE still had enough left over to pay 593 executives, managers and other employees compensation in an aggregate value of $139.53 million, including compensation to 15 executives that, alone, totaled $24.36 million.[15]

In its Application, SCE says that it "realizes" that its request is "substantial."[16] Nevertheless, in an attempt to persuade the Commission that this massive increase will result in "just and reasonable rates," SCE argues that the Commission should not look at the cost per kilowatt-hour of electricity.[17] Instead, SCE suggests the Commission should focus on the average annual cost per customer, which it argues is "well below the national average."[18] This argument is disingenuous on multiple levels.

First, comparing the average annual cost per customer across the entire United States fails to take into account SCE's moderate climate that results in less energy consumed by SCE's ratepayers than the national average.[19] Second, SCE fails to account for reduced consumption resulting from energy efficiency incentives, for which SCE is well-compensated in other

---

[13] Ex. DRA-78, DRA-SCE-GCN-AUDIT-008, Q/A 15.

[14] Ex. SCE-15, Appendix A, Tables for Testimony SCE -10, Vol. 1.

[15] Ex. Joint Parties- 3, 4 and 5, Data Request Set NAAC_LBCGLA_BEC, SEC-019, Q/A 1 &2.

[16] Ex. SCE-01, p. 6, lines 29-31.

[17] Application, p. 25, line 1-4

[18] Ex. SCE-01, p. 25, lines3-4.

[19] *See* 8 RT 658, Litzinger/ SCE.

proceedings.[20] Unless these and other factors are taken into account, reliance on average annual cost – based on customer use – is misleading as a measure of the justness and reasonableness of rates, as any ratepayer in SCE's service territory will attest.

The proper measure, the industry standard, is how much per kilowatt hour SCE is charging its customers. By that measure, SCE's residential ratepayers pay *more* for energy than the average California residential customer, and more than the average residential customer in any other region in the continental United States except New England."[21]

As California continues to struggle through the economic crisis with unprecedented budget shortfalls and the highest unemployment rate in 25 years, SCE's Application shows no effort on the part of the Company to contain the costs it seeks to pass off to its ratepayers. Customers in SCE's service territory have been especially hard hit by the economic downturn. Approximately one *third* of SCE's residential ratepayers are on low income rate assistance, or CARE,[22] rates.[23] In Kern and Tulare counties, nearly half of the households are eligible for CARE rates,[24] and in Imperial County, more than 73% qualify.[25] Apart from the fact that it is SCE's other ratepayers who actually fund the CARE discount, there is also an unknown number of SCE's residential customer whose income is too high for CARE eligibility, but is considered "low" by State of California standards for public assistance purposes.[26]

If ever there was a time to minimize the impact of rate increases on SCE's customers, it surely is now. The Commission's careful review of SCE's bloated revenue requirement forecasts has never been more urgently needed.

---

[20] *See, e.g.* Decision Regarding the Risk/ Reward Incentive Mechanism (2010) D.10-12-049.

[21] Ex. DRA-28, Energy Information Administration, Table 5, Residential Average Monthly Bill by Census Division and State, http://www.eia.doe.gov/cneaf/electricity/esr/table4.xls. According to the most recent EIA report, in 2009, when SCE's average retail rate for residential customers was 15.32 cents/ kWh, the average rate in California was 14.74 cents/ KWh. Only New England, at 17.47 cents/ kWh, and Hawaii and Alaska, at 21.31 cents/ kWh, had higher rates.

[22] California Alternate Rates for Energy

[23] 8 RT 729, Litzinger/SCE.

[24] Ex. DRA-15, p. 8.

[25] Id.

[26] Ex. DRA-25, 8 RT 732, Litzinger/SCE.

2.2. Impact on State and Local Economy

SCE includes in its testimony a study SCE commissioned from IHS Global, to measure the "Economic Impacts of Proposed Capital Expenditures" on the California economy if the Commission approves SCE's proposed capital expenditures.[27] DRA recommends this study be given no weight.

In its last GRC, SCE offered a similar study by the same consulting firm, also claiming that the capital expenditures SCE proposed then would "increase the economic stimulus to the Southern California economy."

DRA attempted to verify this claim from SCE's last GRC, and asked SCE to "describe all efforts SCE has made or will make, to determine the actual impacts of the 2009 expenditures in each of the categories and for each of the regions listed [in the 2009 "study."]. SCE's response was that it "... has not made an effort to determine the actual impacts of the 2009 expenditures ..." and that it had "... no plans to determine the actual impacts for 2009."[28] DRA asked that SCE consider DRA data requests as ongoing: "If, at a later date, SCE and/or Beacon Economics determines the actual impact for [Employment, Output, Value Added, Labor Income and State and Local Taxes] for 2009, please provide the information to DRA with documentation sufficient to allow for independent verification."[29] After receiving SCE's responses to that set of data requests, DRA rephrased the questions to ask for all efforts *IHS Global* had made or would make to identify actual total capital expenditures and their impacts on Employment, Output, Value Added, Labor Income and State and Local Taxes.[30]

Neither the study authors nor SCE made any effort to determine whether the claims about SCE's proposed capital expenditures were ever borne out. The so-called "study," is nothing more than a computer modeling exercise. DRA made its requests in January 2011. In February 2011, SCE sent its responses to DRA, essentially refusing to do anything to validate the method or conclusions of the study.

---

[27] Ex. SCE-10, Vol. 1, p. C-2.

[28] Ex. DRA-79, DRA-SCE-107-CKT Q/A 1a, 1b, 1c.

[29] Id.

[30] Ex. DRA-80, DRA-SCE-CKT-123, Q/A 1a, 1b, 2a, 2b, 3, 3a.

And there the matter rested until July 25, 2011, when Commissioner Simon asked the following:

> Q: From your application, you are projecting 12,760 additional jobs by way of this rate case filing. Is that number accurate?
>
> A: Southern California, we were citing a study done by an economics consulting firm which found that number. We found it plausible to use.
>
> Q: In your 2009 rate case, as I recall, similar to this general rate case, there was an emphasis on Southern California's need for infrastructure upgrade. Much of your distribution system is World War II vintage or right after World War II vintage. And the job growth that would come from these investments, was – do you have figures that would demonstrate to date the net gain in jobs that resulted from the planned expenditures of your last general rate case?[31]
>
> A: I don't have a precise number.
>
> Q: Is that information attainable? Is it possible for SCE to calculate those figures? Because this seems to be a strong impetus of the rate case, not only your need for infrastructure upgrades, but the fact that these infrastructure upgrades could benefit the local economy that you serve.
>
> A: I would think that the consulting firms that we use to make the projections could also do a look back as well using similar techniques to do it….

On August 11, 2011, SCE provided Exhibit 30, purportedly to respond to Commissioner Simon's questions. Exhibit 30 does not do so. One and a half pages of unsubstantiated arguments and six charts with no supporting documentation do not "…demonstrate to date the net gain in jobs that resulted from the planned expenditures of SCE's last general rate case."

Despite the request that SCE provide sufficient documentation to allow for independent verification of SCE's claims, SCE did not do so.[32] SCE has completely failed to show that this study, or the conclusions SCE seeks to draw from it, should be given any weight by the Commission.

---

[31] 8 RT 664

[32] Ex. DRA-80.

2.3. SCE's Threats of Layoffs

SCE devotes a substantial amount of its Rebuttal testimony to arguments like the following: "DRA Targets the SCE Rank and File Workforce for Deep Cuts,"[33] and "DRA & Intervenors' Capital Expenditure Cuts Harm Electric System Infrastructure & Reduce Jobs."[34] SCE also includes charts ostensibly to show that adoption of DRA's and intervenors' proposals would leave SCE "…with a workforce 29% below 2009 levels, or 38% below [SCE's]current workforce."[35] SCE also says that, "If the Commission Adopts DRA's deep Cuts to The SCE Workforce, The Company Should Be Entitled to Recover Severance Costs in Rates."[36]

SCE has made all these threats before. In SCE's last GRC, SCE argued in its brief that "DRA and intervenors have proposed deep cuts, not only to SCE's GRC forecast, but they would cut funding below recorded 2006 levels."[37] And, "DRA would cut 2,213 jobs from SCE's forecast, 1,488 immediately."[38] Also, according to SCE's TY 2009 brief, this "immediate layoffs of 1,488 employees..." "...would necessarily have to include severance costs of $69 million with [DRA and intervenors] do not include in their forecasts."[39] In the last GRC, for TDBU in particular, SCE argued that "DRA's proposal cuts 1,228 jobs from TDBU forecast; 485 immediately."[40]

SCE's was still making this threat in March 2009 in an ex parte contact after the Proposed Decision (PD) in A.07-11-011 declined to give SCE everything it had asked for. According to one ex parte notice "...adoption of the PD would be devastating to the reliability of SCE's electric distribution system. Thousands of SCE employee and contractor jobs would be lost."[41]

---

[33] Ex. SCE-16, line 2.

[34] Ex. SCE-16, Figure IV-5, Heading.

[35] Ex. SCE-18, Vol. 1.

[36] Ex. SCE-16, p. 14.

[37] Ex. DRA-35, Excerpts from SCE TY 2009 GRC Opening Brief, Summary of Recommendations, 1st page.

[38] Id, 2nd page, chart entitled "SCE Employee Forecast."

[39] Id., at first bullet point.

[40] Id, at p. 36.

[41] Ex. DRA-27, SCE Notice of Ex Parte Communication, March 2009.

In the end, the Commission adopted the Alternate Decision of President Peevey which gave SCE more ratepayer funding than the PD would have done, but still adopted some of DRA's recommendations and those of other Intervenors. SCE did not lay off any employees in 2009, 2010 or 2011.[42] SCE provided safe and reliable service in 2009, 2010 and 2011.[43]

SCE's threats in this GRC should be given no more credence than they were given in the last GRC. The Commission should adopt a revenue requirement based on the record evidence.

2.4. Summary of Recommendations

The following is a brief summary of some of the areas of disagreement between DRA and SCE in this rate case:

- Transmission and Distribution Operation and Maintenance (O&M) expenses – DRA's most significant adjustments are associated with Maintenance of Overhead and Underground Lines, and storm-related costs.[44]
- Transmission and Distribution capital expenditures – DRA's most significant adjustments are associated with Distribution Substation projects, Rule 20B conversions, 4kV Substation projects, Cable in Conduit Replacements,[45] Advanced Technology and Capital Maintenance Programs.[46]
- Nuclear Generation costs – DRA's most significant adjustments are associated with SCE's proposal to "share" nearly $40 million in O&M savings from SONGS personnel reductions with SCE shareholders, instead of having all the savings flow directly to ratepayers as standard ratemaking principles would require. DRA also recommends disallowance of approximately $40 million from the capital expenditures forecast for the SONGS High Pressure Turbine Retrofit Program on the basis that the SONGS Unit 2 retrofit was already authorized in the 2009 GRC, and the 40% contingency assumed by SCE for both the Unit 2 and Unit 3 retrofits is too high given that the Unit 2 retrofit will commence in less than four months.[47]
- Non-Nuclear Generation costs -- DRA's most significant adjustments are associated with the McGrath Peaker project, which is unlikely to be in

[42] 9 RT 930, Ziegler/ SCE;

[43] 8 RT 652, Litzinger/ SCE.

[44] Ex. DRA-5

[45] Ex. DRA-6

[46] Ex. DRA-7

[47] Ex. DRA-8.

service in the Test Year. Consequently, DRA recommends a disallowance of $20 million from the fossil fuel capital budget forecast, and a disallowance of $2.859 million from the O&M forecast. DRA also opposes SCE's proposal to move its Solar Photovoltaic Program costs into Test Year O&M. The balancing account established for that program should be preserved.[48]

- Customer Service costs – DRA's most significant adjustments are associated with Customer Records & Collection expenses, Local Public Affairs expenses, meter-related costs, and capitalized software.[49]
- Operations Support costs – DRA's most significant adjustments are associated with expenses for Corporate Security, Corporate Resources and Operations Support Services as well as various capital expenditures for the Alhambra Data Center, and the Critical Infrastructure Protections Physical Security projects.[50]
- Administrative and General (A&G) expenses – DRA's most significant adjustments are associated with expenses for liability insurance, Outside Services, Outside Counsel and various labor costs.[51]
- Human Resources and Executive Officers, and Incentive and Recognition Programs – DRA's most significant adjustments are associated with Short-Term and Long-Term Incentive Program costs.[52]
- Power Procurement Costs – DRA's most significant adjustments are associated with SCE's requests for new employees.[53]
- Pensions and Benefits – DRA's most significant adjustments are associated with pension contributions, benefits costs (*e.g.*, medical plans, retirement savings plan, etc.), and Executive benefits.[54]

Information Technology Costs – DRA's most significant adjustments are associated with expenses for Application Services, Technology and Risk Management, and the removal of all capital and expense forecasts associted with the Market Redesign and Technology Upgrade (MRTU)[55]

---

[48] Ex. DRA-9.

[49] Ex. DRA-10.

[50] Ex. DRA-11

[51] Ex. DRA-12.

[52] Ex. DRA-13.

[53] Ex. DRA-14.

[54] Ex. DRA-15.

[55] Ex. DRA-16.

- Depreciation Expense and Reserve – DRA's most significant adjustment to SCE's proposal is to recommend that SCE's current net salvage rates adopted in D.09-03-025 remain unchanged.[56]
- Rate Base – DRA's most significant adjustment is associated with the ratemaking treatment of Customer Deposits.[57]
- Post- Test Year Ratemaking – DRA's most significant adjustment is associated with using the Consumer Price Index (CPI) as the basis for developing post-test year increases.[58]
- Results of Examination – DRA's most significant adjustments are associated with recorded expenses for the WISER Program as well as lower rates for Allowance for Funds Used During Construction.[59]

2.5. Procedural Background

SCE's GRC Application was accompanied by over 5,600 pages of testimony by 88 different witnesses, and 16 boxes of workpapers. In accordance with Rule 2.6 of the Commission's Rules of Practice and Procedure, DRA filed its Protest on December 29, 2010. Numerous other parties, including The Utility Reform Network, (TURN), Aglet Consumer Alliance (Aglet), the Black Economic Council, the Latino Business Chamber of Greater Los Angeles, the National Asian American Coalition (collectively referred to as Joint Parties), Disability Rights Advocates, the Port of Long Beach, the Eastern Sierra Ratepayer's Association (ESRA), the Sierra Club, and the Vote Solar Initiative requested and were granted party status over the course of the proceeding.

At the pre-hearing conference on January 31, 2011, SCE proposed a schedule seeking a final decision before the end of 2011. TURN and DRA proposed a schedule similar to those the Commission has used to process other large energy utility GRCs during the past decade.

On March 1, 2011, a Scoping Memo and Ruling was issued adopting a schedule with DRA testimony due May 11, 2011, Intervenor testimony due June 1, 2011 and Rebuttal testimony due July 3, 2011.[60] Hearings were scheduled to begin on July 25, 2011.

---

[56] Ex. DRA-17.

[57] Ex. DRA-19, and Ex. TURN-3.

[58] Ex. DRA-21

[59] Ex. DRA-22.

[60] The due date for Rebuttal Testimony was changed to July 5th.

On July 5, 2011, SCE's submitted its Rebuttal, adding another 35 volumes of testimony and eight more witnesses. On June 15, 2011, SCE filed a Motion to Strike portions of the direct testimony of TURN, DRA and Disability Rights Advocates to which DRA, and TURN and Disability Rights Advocates responded. On July 20, 2011, five days before hearings began, SCE filed a Motion to Compel a data request response from DRA that DRA had, in fact, already answered. Both motions were denied on the first day of the evidentiary hearings.[61]

Hearings were held for two days in Los Angeles, and 14 days in San Francisco, concluding on August 26, 2011.

2.6. Forecasting Issues

2.6.1. Overview

As the Commission has noted in prior GRC decisions, "there are a number of acceptable methodologies for forecasting test year costs."[62] In this TY 2012 GRC, DRA, SCE and other parties have used averages and trends of recorded costs, the most recent recorded costs, and forecasts based on budgets. In the past, in these situations, the Commission has found that:

> [d]epending on circumstances, one method may be more appropriate than others. Under other circumstances, two or more methods may be equally appropriate. In general, the parties' testimony should explain (1) why its methodology is appropriate, (2) why it is better than methodologies proposed by other parties, and (3) why the results are reasonable.[63]

However, in connection with forecasts using budget-based methodologies, the Commission has cautioned that:

> While incremental budgets may capture anticipated increases over historic levels it is not always clear that (1) additional productivity from past year or current projects are also being properly cast on a forward basis, (2) that certain historic costs will be necessary in future years and can, instead, be used to offset new costs, and (3) that the proposed budgeted costs are not included in another form in the embedded recorded data. *When these types of issues are raised, the utility has the responsibility to demonstrate the*

[61] 8 RT 601.

[62] D.06-05-016, mimeo, p. 10.

[63] Id., at pp. 10-11.

> *reasonableness of its estimates, even if it means identifying and justifying all costs embedded in the base year amount.*[64]

DRA's forecasts have attempted to incorporate all of these principles. SCE, on the other hand seems to rely heavily on a decision the Commission issued in a PG&E GRC 22 years ago. That decision included, in part, the following:

> From these descriptions of the parties' methodologies, we may discern general agreement on certain principles for developing a base estimate *of 1990 expenses:*
>
> If recorded expenses in an account have been relatively stable for three or more years, *the 1987 recorded expenses is an appropriate base estimate for 1990.*
>
> If recorded expenses in an account have shown a trend in a certain direction over three or more years, *the 1987 level is the most recent point in the trend and is an appropriate base estimate for 1990.*
>
> For those accounts which have significant fluctuations in recorded expenses from year to year, or which are influenced by weather or other external forces beyond the control of the utility, an average of recorded expenses over a period of time (typically four years) is a reasonable base expense *for 1990.*[65]

SCE seems to have interpreted these principles as eternal, black letter law. Except, of course, when the application of these principles does not serve SCE's purposes, as with SCE's proposed "backcast forecast" to inflate Claims expenses.[66]

DRA assumes that the principles in D.89-12-057, like the principles enunciated in more recent GRC decisions, are examples of the reasoning the Commission applies to these cases. DRA also assumes that the Commission, in this case as well, will be guided by the law, the record and Commission policy.

2.6.2. Capital Expenditures Versus Capital Additions

For capital areas, DRA analyzed SCE's proposed capital expenditures occurring from the end of the last recorded year through the end of the Test Year 2012. Capital expenditures, once they become plant additions, are cumulative in nature. Expenditures made during one year are added to expenditures that were made in previous years.

---

[64] Id., at p. 11, emphasis added.

[65] Re PG&E (1999) 34 CPUC 2d 199, 231; D.89-12-057, emphasis added.

[66] See Section 9.4.2. below.

In some exhibits and workpapers, SCE presented its capital expenditures in direct nominal dollars. "Direct" dollars refers to the fact that SCE's capital expenditure estimates do not include various loadings, such as the capitalized portions of Pensions and Benefits, Payroll Taxes, Injuries and Damages, Administrative and General Expenses, etc. These various loadings are estimated separately and are allocated to the various capital projects by the Results of Operations (RO) computer model. "Nominal" dollars refers to the fact that SCE's forecasts are presented with estimates keyed to the year in which they occurred. For example, a 2011 capital expenditure will use 2011 dollars for its forecast, rather than presenting the estimate in constant dollars from a prior year.[67]

DRA's exhibits do not specifically address capital additions, but rather, are organized around capital expenditures. The distinction between the two is important. Capital expenditures, as the term implies, reflect the capital dollars that SCE spends in a given year. No consideration is given as to whether or not those expenditures result in projects that are actually completed (and considered to be "used and useful") during the year.

In contrast, capital additions reflect the dollar amount of projects that are completed during a given year, regardless of when the expenditures actually took place. SCE's capital witnesses provide testimony regarding the magnitude of the direct capital dollars that are estimated to be spent each year, not how much is actually being booked to plant. DRA's analyses and recommended direct capital adjustments are also stated in terms of capital expenditures.

When analyzing data in this format, the impact of recommended adjustments to capital expenditures may not show up in the year in which they are made. For example, suppose a capital project is scheduled to begin construction in 2011, but is not scheduled to be completed until 2012. If DRA recommends an adjustment to the 2011 expenditures, there will not be a revenue requirement impact until 2012, when the project is completed, is booked to plant-in-service, and begins earning a return.[68]

3. Evidentiary Standards and Burden of Proof

The Commission is charged with the responsibility of ensuring that all rates demanded or received by a public utility are just and reasonable; "no public utility shall change any rate...

---

[67] See Ex. DRA-6, pp. 6-7.

[68] Ex. DRA-6, pp. 7-8.

except upon a showing before the Commission, and a finding by the Commission that the new rate is justified."[69]

In its decision in SCE's TY 2006 GRC, the Commission confirmed that the burden is on the utility:

> As the Applicant, SCE must meet the burden of proving that it is entitled to the relief it is seeking in this proceeding. SCE has the burden of affirmatively establishing the reasonableness of all aspects of its application. Intervenors do not have the burden of proving the unreasonableness of SCE's showing.[70]

As the Applicant in this rate case, SCE has the burden of proving that each of its proposals is reasonable.

With the burden of proof placed on the Applicant in rate cases, the Commission has variously held that the standard the Applicant in a GRC must meet is "clear and convincing evidence"[71] or "preponderance of the evidence."[72] According to the decision on the TY 2009 GRC for Southern California Edison:

> ... the Commission has held that the standard of proof the applicant must meet is that of a preponderance of evidence, which the Commission has, at times, incorrectly referred to as "clear and convincing" evidence. Evidence Code 190 defines proof as the establishment by evidence of a "requisite degree of belief." We have analyzed the record in this proceeding within these parameters.

Thus, in one paragraph, D.09-03-025 goes against a long line of other Commission decisions that find the standard of proof to be "clear and convincing evidence." D.09-03-025 offered no explanation of why "clear and convincing evidence" is the "incorrect" standard to apply. General rate increase proceedings going back at least as far as 1952 have held that "...a utility seeking an increase of rates has the burden of showing by clear and convincing evidence that it is entitled to such increase."[73] In fact, the Commission applied this standard in PG&E's

---

[69] Public Utilities Code §§ 451, 454.

[70] Opinion on Southern California Edison Company's Test Year 2006 General Rate Case Increase Request (2006) D.06-05-016, mimeo, p. 7.

[71] Alternate Decision of President Peevey on Test Year 2009 General Rate Case for Southern California Edison Compan (2009) D.09-03-025, p. 8.

[72] Opinion (2000) D.00-02-046, p. 36 (PG&E TY 1999 GRC)

[73] Southern Counties Gas Company of California (1952) 51 CPUC 533, 534; D.46876.

last contested GRC Application,[74] and reiterated it in an opinion deciding applications for rehearing:

> We have historically, although not wholly consistently, applied the clear and convincing burden of proof to utilities seeking general rate [*6] increases. We applied the clear and convincing standard to PG&E in this case. This standard is applicable to all aspects of PG&E's showing. The Decision contains six pages (pp. 34-40) discussing at length both the clear and convincing standard and the substantial evidence standard. Moreover, the Decision explicitly reiterates later that "we must insist upon PG&E demonstrating, for each component of its proposed revenue requirements, that it produce **clear and convincing evidence.** To the extent it fails to do so, we **cannot grant its requested revenue** increase.[75]

In a 2003 decision resolving a water utility GRC, the Commission again held that the standard of proof is clear and convincing evidence. Why D.09-06-025 suddenly departed from this long line of precedent is not explained, and DRA recommends that the Commission affirm that the proper standard of proof for GRCs is clear and convincing evidence.

By any standard, though, SCE has failed to prove that its requested $4.212 billion increase is reasonable. The areas DRA disputes are discussed below.

4. Generation

4.1. Generation – Nuclear Generation

4.1.1. SONGS

SCE requests $270.5 million in SONGS Operation and Maintenance (O&M) expenses for TY 2012[76] and $112.9 million, $115.1 million, and $102.0 million for capital expenditures in 2010, 2011, and 2012, respectively.[77]

As discussed below, DRA recommends that the Commission disallow $19.3 million intended to flow to SCE shareholders as "shared" personnel savings from SONGS O&M, and recommends the following reductions to SCE's capital expenditure forecasts: (1) $36.6 million in 2012 for the SONGS 2 High Pressure Turbine (HPT) retrofit project; (2) $4.696 in 2012 for the SONGS 3 HPT retrofit project; (3) $1.2 million in 2010-2013 for the proposed parking lot

---

[74] D.00-02-046, p. 36.

[75] Order Granting Rehearing D.01-10-031, 2001 Cal LEXIS 917 *6.

[76] Ex. SCE-2, Vol. 1 at 135; Ex. SCE-2, Vol. 3 at 21.

[77] Ex. SCE-17, Vol. 2 at 17.

light project;[78] (4) $1.1 million in 2013 for the service air piping project;[79] and (5) $1.5 million in 2011 for the two cafeteria remodels.[80]

4.1.1.1. SDG&E's Request for SONGS Cost Recovery

SDG&E's cost recovery is dependent on the results of this GRC; DRA made recommendations in the SDG&E GRC regarding cost recovery (A.10-12-005/006, Exhibits DRA-5 and DRA-12).

4.1.1.2. SONGS O&M - SCE's Proposal for Ratepayers To "Share" SONGS Cost Savings With SCE Shareholders

4.1.1.3. Background

SCE proposes substantial personnel reductions at SONGS, including "a reduction of 100 contractor personnel from the contractor headcount expected as of the end of 2011"[81] and a reduction in 2012 of 500 SCE personnel "compared to the SCE headcount at the end of 2009."[82] From these reductions, SCE estimates total O&M savings of approximately $150 million over the rate case cycle, based on annual savings of $100,000 per employee and $160,000 per contractor.[83] SCE anticipates contractor reductions by the end of 2011,[84] but assumes an October 1, 2012 termination date for modeling purposes.[85] SCE also normalizes the net savings over the three year rate case cycle (2012-2014) for ratemaking purposes.[86]

If it were following standard cost-of-service ratemaking principles, SCE would simply forecast these savings from reduced personnel as lower O&M costs, and the savings would automatically be passed through to ratepayers in the form of lower rates – or in this case, a lower revenue requirement increase. However, in conjunction with the *largest* revenue requirement increase it has ever requested in Phase I of a General Rate Case (GRC), SCE proposes that,

---

[78] Ex. SCE-2, Vol. 2 at 28; see also Appendix B, reference #17 at B-19.

[79] Ex. SCE-2, Vol. 2 at 45-46; see also Appendix B, reference #45 at B-47.

[80] Ex. SCE-2, Vol. 2 at 29-30; see also Appendix B, reference #19 at B-21.

[81] Ex. SCE-2, Vol. 1 at 12.

[82] Ex. SCE-2, Vol. 1 at 13.

[83] Ex. SCE-2, Vol. 1 at 14.

[84] Ex. SCE-2, Vol. 1 at 12.

[85] Ex. SCE-2, Vol. 1 at 14.

[86] Ex. SCE-2, Vol. 1 at 14-15.

instead of passing these savings directly through to ratepayers, SCE shareholders should receive 50% of the savings. In support of this extraordinary proposal, SCE argues that both DRA and the Commission have previously approved such sharing proposals.[87]

DRA does not oppose SCE's proposal to reduce personnel at SONGS, nor does it challenge SCE's estimated savings or normalization of those savings over the rate case cycle. However, DRA does oppose SCE's request to share 50% of the net cost savings with its shareholders, rather than having all the savings flow to ratepayers in the form of lower rates.

SCE's proposed workforce reductions stem from a report prepared by Goodnight and Huron Consultants in 2009, which compares SONGS staffing levels to other comparable nuclear facilities.[88] The report was commissioned in the wake of significant management changes at SONGS at the beginning of 2009, which were made in response to, among other things, scheduled outages in the last quarter of 2008 that each lasted a month longer than planned.[89]

The Goodnight and Huron report recommended staffing reductions at SONGS based on comparisons to other peer commercial nuclear stations. While the recommendations were made in 2009, SCE management elected not to implement the recommended changes because of the "extraordinary circumstances" presented by the Nuclear Regulatory Commission (NRC) inspection in November 2009 and the NRC's March 2, 2010 "chilling effects" letter regarding work environment issues at SONGS.[90] SCE explains: "…[I]t was ultimately SCE and SONGS executive management's judgment that it would not be prudent to undertake major organizational changes and staffing reductions at the same time efforts were underway to improve and stabilize the NRC's concerns and the station's performance metrics."[91] SCE argues that with the management improvements wrought by its resolution of NRC's concerns, the time is now right to implement the staffing reductions: "…[T]he 2012 Test Year forecast assumption of achieving NRC oversight stability and forward momentum in performance metrics also means it is appropriate to assume that in the Test Year, SCE can significantly reduce contractor and

---

[87] Ex. SCE-2, Vol. 1 at 14-16; Ex. SCE-17, Vol. 1 at 5-7.

[88] Ex. SCE-2, Vol. 1 at 8.

[89] Ex. SCE-2, Vol. 1 at 6.

[90] The NRC "chilling effects" letter referenced in SCE's testimony at Exh. SCE-2, Vol. 1, page 9 is available at http://pbadupws.nrc.gov/docs/ML1006/ML100601272.pdf.

[91] Ex. SCE-2, Vol. 1 at 9.

SCE personnel at SONGS."[92] The assumption that SCE will achieve "NRC oversight stability" is supported by a letter to SCE from NRC dated September 6, 2011, in which NRC determined that SCE had instituted corrective programs to improve work safety issues, and noted a significant reduction in allegations relating to an unsafe work environment received in 2011. The NRC letter concludes that NRC will no longer consider its "chilling effects" letter for purposes of plant assessment.[93] Thus, it appears the time is more than ripe for SCE to initiate its staffing reduction plans.

4.1.1.4. SCE Has An Obligation To Prudently Manage SONGS

Read carefully, SCE's testimony reveals an era of mismanagement at SONGS publicly exposed by the extended unit outages in the last quarter of 2008, SCE's actions to correct the mismanagement through creation of a "new SONGS Senior Leadership Team (SLT)" implementing various new management programs,[94] and the NRC's public direction to improve management, resulting in additional corrective actions by SONGS management.[95] While SONGS now appears to be on a path to recovery, consistent with established industry models and metrics, none of the management activities to get on this path reflect anything beyond basic prudency, and only after a period of evidently imprudent management. On the path to management improvements, SCE discovered SONGS has been significantly overstaffed, and is now taking steps to correct that problem as well.

In support of its "sharing" proposal, SCE appears to argue that its shareholders should be rewarded for SCE implementing management practices that should have been in place at SONGS many years before. SCE is mistaken.

Utilities have an obligation, in exchange for their rate of return, to prudently operate their business. Prudency encompasses an obligation to be efficient and economic. Prudency is the expected norm – it is not exceptional conduct that requires a "reward". Public Utilities Code § 451 embodies this requirement to be prudent in exchange for a just and reasonable rate. SCE must "furnish and maintain such adequate, efficient, just and reasonable service, instrumentalities, equipment, and facilities . . . . as are necessary to promote the safety, health,

---

[92] Ex. SCE-2, Vol. 1 at 12.

[93] California Energy Markets, Sept. 9, 2011, No. 1146, Item 9 on page 2.

[94] Ex. SCE-2, Vol. 1 at 6.

[95] Ex. SCE-2, Vol. 1 at 7.

comfort, and convenience of its patrons, employees, and the public." Consistent with standard ratemaking principles and § 451, SCE has an obligation to prudently manage SONGS, and its shareholder do not now deserve a reward for SCE finally meeting this basic obligation.

SCE also appears to argue that its shareholders are entitled to share in the cost savings from the personnel reductions because they "funded" the management improvement programs that will ultimately result in the projected savings. SCE claims the "turnaround … has cost shareholders at least $45 million" in costs exceeding the authorized O&M in the 2009 GRC.[96] SCE's argument lacks merit on several levels.

First, as observed above, SCE's testimony reveals that staffing reductions at SONGS are long overdue. Ratepayers have been paying these extra staffing costs since at least 2010, and likely longer. Had the need for staffing reductions been recognized sooner, in addition to avoiding those employment costs, SCE's new management programs, which focus on training for SONGS workers, would have cost less.

Second, SCE's testimony suggests that the program costs related to addressing NRC concerns regarding "Safety Conscious Work Environment" issues were completely unanticipated, and therefore not included in the 2009 GRC. However, there is a long history of active mismanagement at SONGS in the last decade, including management's failure to support a "culture of safety." As the Commission's D.08-09-038 plainly stated: "We have found numerous safety violations at SONGS with complicity of SCE management."[97] The decision details years of active mismanagement at SONGS, including express directives from SONGS management to workers to underreport work place injuries, among other things.[98] In the wake of D.08-09-038's damning conclusions, NRC concerns regarding SONGS lack of a safety culture in November 2009 and March 2010 could have been anticipated. In fact, even the March 2, 2010 "chilling effects" letter noted that the issues raised in the letter were not new to SCE:

> … [T]he NRC's 2009 Mid-Cycle Assessment notes that this was the fourth consecutive assessment period with substantive cross-cutting issues in the areas of human performance and problem identification and resolution.[99]

---

[96] Ex. SCE-2, Vol. 1 at 11-13.

[97] Investigation into the Practices of SCE (2008) D.08-09-038, mimeo, p. 93.

[98] See, e.g., D.08-09-038, mimeo, pp. 57-67 and Findings of Fact 37-43.

[99] The March 2, 2010, "chilling effects" letter is publicly available on the NRC's website at

The "chilling effects" letter explains the bases for NRC's concerns. Among them: "The NRC has received a significant increase of allegations from onsite sources at SONGS to *nearly ten times the industry median in 2009*."[100]

Given the extended history of workplace safety issues at SONGS, SCE's failure to recognize the need for and include the costs of corrective action management programs in its 2009 GRC reflects its own continued mismanagement at that time.

SCE's 1992 and 2006 GRC Decisions Are Not Relevant Here

SCE argues that its ratepayers should "share" 50% of the savings realized from staffing reductions because this policy is consistent with the Commission's decisions in its 1992 GRC (D.91-12-076) and its 2006 GRC (D.06-05-016).[101] As set forth above, SCE has failed to make a case that sharing is justified – as a practical matter - under any of the facts of this case. If anything, the facts suggest that SCE has engaged in years of mismanagement that warrant other types of regulatory action, but certainly no "reward" to its shareholders.

Further, SCE's reliance on these two Commission decisions as precedent for its sharing proposal in this GRC is grossly misplaced. D.06-050-016 contains *no* language supporting a SCE sharing program. D.06-05-016 *does*, however, discuss, *and reject,* a SDG&E sharing proposal *specific to SONGS*. As D.06-05-016 explains, SDG&E proposed its Cost Containment Incentive Mechanism (CCIM) for SONGS, which SCE opposed, because SDG&E was "extremely disturbed with SCE's *historic inability*, as the Operating Agent under the SONGS Operating Agreement, to manage SONGS 2&3 costs, as demonstrated over time by the fact that SCE routinely spends considerably more on both O&M and capital related costs than it forecasts."[102] D.06-05-016 rejected the SDG&E proposal for SONGS, preferring instead, cost of service ratemaking:

---

http://pbadupws.nrc.gov/docs/ML1006/ML100601272.pdf The letter explains:

The Nuclear Regulatory Commission (NRC) has concluded that some employees in multiple workgroups at SONGS have the perception that they are not free to raise safety concerns using all available avenues, and that management has not been effective in encouraging employees to use all available avenues without fear of retaliation. …

The NRC observed that not all SCE managers have completed Safety Conscious Work Environment Training ….

[100] Id. at page 1 (emphases added).

[101] Ex. SCE-2, Vol. 1 at 15-16.

[102] D.06-05-016, mimeo, p. 310 (emphases added).

> … [W]e are not convinced that an incentive mechanism at this time will necessarily lead to lower costs, over the long term, than would occur under normal cost of service ratemaking. … We will continue to evaluate and set authorized levels of rate recovery for SONGS on a cost of service ratemaking basis.[103]

Thus, nothing in D.06-05-016 reflects Commission support for the type of sharing treatment SCE proposes here. Rather, D.06-05-016 expresses a preference for traditional cost of service ratemaking as the appropriate mechanism for controlling SONGS O&M costs.

SCE's reliance on D.91-12-076 is similarly inappropriate. That decision addressed SCE's Cost Containment Program, begun in 1988, which had a program goal "to limit the growth of *all* O&M expenses to inflation less 1.5%."[104] While a properly-designed cost-containment program for *all* of SCE's O&M expenses (utility-wide) may make sense, that is not what SCE proposes here. Rather, SCE proposes to cherry-pick a single reduced expense occurring only at SONGS - for sharing with its shareholders. SCE takes on none of the burden of a holistic cost containment program – like that discussed in D.91-12-076 - which would require it to produce cost savings across many expense categories and throughout the utility before shareholders are rewarded.

In sum, SCE has failed to meet its burden of proving that a "reward" to its shareholders would result in just and reasonable rates. At best, the Commission can hope that SCE is on the path to management stabilization at SONGS. At worst, the evidence suggests years of SONGS mismanagement (subsidized by ratepayers), and that SCE has unreasonably delayed personnel reductions at SONGS purely to preserve the issue of "sharing" for this rate case. Had SCE instituted the reductions in the 2009 GRC cycle the savings would have flowed through to ratepayers with no further discussion, and they should do so here. DRA recommends that the Commission disallow $19.3 million from SONGS O&M expense request in TY 2012.[105]

4.1.1.5. SCE's High Pressure Turbine Retrofit Project

SCE proposes to spend $36.6 million in 2011 to retrofit the High Pressure Turbine (HPT) at SONGS 2 and an additional $36.6 million on SONGS 3 in 2013, for a total of $73.2 million in

---

[103] D.06-05-016, mimeo, p. 323.

[104] Re Southern California Edison (1991) 42 CPUC 2d 645; D.91-12-076, 1991 Cal. PUC LEXIS 911, p. *14 (emphases added).

[105] $19.3 million represents SCE's ownership share in the $24.75 million annual savings that SCE proposes to transfer to shareholders.

capital expenditures.[106] During cross-examination, SCE admitted that the schedule for the SONGS 2 HPT retrofit had slipped from 2011 to 2012.[107] These projects have been in the planning stages since 2007,[108] and a cost of $41 million for SONGS 2 was included in the Test Year 2009 GRC.[109] SCE assumes that the retrofit will increase SONGS 2 and 3 energy output and capacity by 2%, approximately 48 MW.[110] SCE includes a 40% contingency rate for both projects: $10.5 million for SONGS 2 and $9.9 million for SONGS 3.[111]

DRA requested from SCE a HPT retrofit cost-effectiveness study, and learned that SCE estimated a 1.4 benefit-to-cost ratio under "conservative" assumptions; but the benefit-to-cost ratio drops to 1.0 if lower gas prices are assumed.[112] SCE's data response included a portion of the company's 2009 GRC testimony, which shows a $41 million capital cost to retrofit SONGS 2 in 2011 and a 1.22 benefit-cost ratio.[113]

While SCE's direct testimony states that SCE expects a 48 MW capacity increase from the HPT retrofits, SCE's rebuttal testimony offered the rather broad range of 6 MW to 100 MW.[114] SCE admitted that it did not perform any sensitivity analyses for cost-benefit analyses for the HPT projects with varying capacity levels.[115] SCE's failure to perform any sensitivity analyses raises doubts about the validity of SCE's 48 MW capacity increase forecast and additional doubts about the cost-effectiveness of the HPT retrofits in general.

While DRA does not oppose the proposed HPT retrofit project, DRA recommends two disallowances. First, given that $41 million was authorized for the SONGS 2 HPT retrofit in SCE's 2009 GRC, DRA opposes including the $36.6 million SCE now requests for this project

---

[106] Ex. SCE-2, Vol. 2 at 25.

[107] 16 RT 2393:15-22, Bauder/SCE and 16 RT 2398:18-26, Bauder/SCE.

[108] 16 RT 2399:13-15, Bauder/SCE.

[109] Decision Granting Petition to Modify D.05-12-040 (2011) D.11-05-035, mimeo, p. 2; and 16 RT 2392:6-8, Bauder/SCE.

[110] Ex. SCE-2, Vol. 2 at 24.

[111] Ex. SCE-2, Vol. 2, Part 2 workpapers at 126 and 132.

[112] Ex. DRA-8, p. 8, citing SCE response to DRA data request 34, Q.4.

[113] SCE-17, Vol. 2 at A-20 to A-45, which provides SCE's response to DRA data request 34, Q.4, which includes portions of SCE's TY 2009 GRC testimony from Ex. SCE-02, Vol. 5. See specifically pages 1 and 8 of that 2009 GRC testimony.

[114] Compare SCE-2, Vol. 2 at 24 to SCE-17, Vol. 2 at 6.

[115] 16 RT 2397:18 through 16 RT 2398:13, Bauder/SCE.

in TY 2012. It is not appropriate for ratepayers to pay for this project twice. The Commission should disallow $36.6 million from SCE's capital expenditures forecasted for 2012.

Second, the 40% contingency for the SONGS 3 HPT retrofit should be reduced to no greater than 20%. As testified to by SCE, the SONGS 3 HPT retrofit is "essentially identical" to the SONGS 2 HPT retrofit,[116] has been in planning since 2007,[117] and is scheduled to commence shortly, on January 10, 2012.[118] In a data response attached to its Rebuttal Testimony, SCE explains the process it used to arrive at the 40% contingency for the two HPT retrofits:

> SCE estimates project contingency based on the Association for the Advancement of Cost Engineering (AACE) guidelines … When determining project contingency, several factors are considered, such as project scope and risk, project costs and level of effort. These factors are then translated to a level of project definition and an estimate classification. The document attached below titled "AACE Contingency Categorization" depicts AACE's matrix. SCE uses the AACE matrix and classification guidelines to then assess a percent of project contingency. SCE's percent of project contingency to estimate class and level of project definition is as follows:

Estimate Class	Level of Project Definition	Percent of Contingency
Class 1	50% to 100%	5% to 20%
Class 2	30% to 70%	5% to 20%
Class 3	10% to 40%	20% to 40%
Class 4	1% to 10%	45% to 60%
Class 5	0% to 2%	65% and Above

> Following the contingency and estimating guidelines described … above, a 40% contingency was applied to the U2 HPT project…. Detailed plans, including design documents (diagrams/drawings), project plans, schedules, and Work Breakdown Structure (WBS), have not been developed at this stage, requiring a 40% contingency.[119]

[116] 16 RT 2391:3-4, Bauder/SCE.

[117] 16 RT 2399:13-15, Bauder/SCE.

[118] 16 RT 2398:25-26, Bauder/SCE.

[119] Exh. SCE-17, Vol. 2 at A-75 to A-76, citing SCE Response to DRA-SCE-034-TXB, Q/A 14.

Reducing SCE's 40% contingency is appropriate given the imminent commencement of work on the SONGS 2 HPT retrofit. SCE has testified that the design for the turbine upgrade is complete and the materials needed for the retrofit have been ordered.[120] When asked what the biggest component of the contingency was, SCE's witness said that he did not recall but that "I would expect materials though would be a big driver."[121] The AACE matrix relied upon by SCE suggests that a 40% contingency is only appropriate when the level of project definition is 10% to 40%. The level of the HPT retrofit's project definition – a project planned to commence in less than 4 months – is clearly well over 50% at this stage, justifying a contingency of 5% to 20% pursuant to the AACE matrix. SCE's 40% contingency for the Unit 3 HPT retrofit is unsustainable given that the Unit 3 project is "nearly identical" to the Unit 2 project, which will be underway shortly. DRA recommends adjustment of the contingency for Unit 3 to 20%, which should be reflected as a disallowance of $4.969 million in the 2012 capital expenditure forecasts for SONGS.

4.1.1.6. Parking Lot Lighting Project

SCE proposes to spend $1.2 million in capital expenditures in 2010-2013 to install battery-powered, solar-cell charged light emitting diode (LED) overhead lighting in three parking lots at SONGS.[122] SCE's plans are preliminary at best: "SCE will conduct lighting surveys in SONGS parking lots 2, 3 and 4, and as well survey access and ingress/egress routes to the parking areas. SCE will use this data to select areas to modify or replace SONGS parking lot lighting, including light poles and fixtures."[123] The project cost includes a relatively high 42% contingency of $290,000.[124]

SCE states "[t]here are certain areas of SONGS parking lots 2, 3 and 4 where vision is limited due to insufficient lighting. This could *potentially* contribute to a situation where an injury *may* occur (e.g. an injury caused by an inconspicuous object or presence of rattlesnakes *and* mountain lions)."[125] DRA asked SCE whether improving the lighting in the SONGS

---

[120] 16 RT 2399:21-26, Bauder/SCE.

[121] 16 RT 2411:11-15, Bauder/SCE.

[122] Ex. SCE-2, Vol. 2 at 28; see also Appendix B, reference #17 at B-19.

[123] Ex. SCE-2, Vol. 2 at 28, lns. 10-12.

[124] Ex. SCE-2, Vol. 2, Pt. 2 workpapers at 141, ln. 4.

[125] Ex. SCE-2, Vol. 2 at 28, lns. 20-22 (emphasis added).

parking lots would improve the predation opportunities of "rattlesnakes and mountain lions"; SCE responded that "SCE does not know whether the lighting improvements in SONGS parking lots would improve or reduce predation opportunities of 'rattlesnakes and mountain lions.'"[126]

DRA recommends disallowance of funding for the site parking and pedestrian lighting project. SCE does not appear to have fully planned this project, the company's justification for the project is questionable given the lack of evidence of snake or mountain lion incidents, or that installing lighting in the parking lot would deter such incidents. Finally, the 42% contingency appears high for what should be a relatively straight-forward project.[127]

4.1.1.7. Service Air Piping Project

SCE proposes to spend $1.1 million in capital expenditures in 2013 to upgrade the SONGS' service air system piping.[128] SCE admits that the project was delayed from 2009: "[t]his project was deferred from its originally estimated in-service year of 2009 to provide funding for emergent projects having higher priority."[129] In response to a DRA data request, SCE confirmed that the project was part of the last GRC: "SCE listed the Service Air Piping Project as a planned capital project within the 2009 GRC. SCE did not complete this project as planned."[130] The project cost includes a 20% contingency cost of $150,000.[131]

DRA recommends disallowance of funding for this service air piping project. This project was included in the 2009 GRC. DRA does not oppose the project itself, only that ratepayers should not pay in TY 2012 for a project included in the 2009 GRC.

4.1.1.8. Cafeteria Remodeling Projects

SCE proposes to spend $1.5 million in capital expenditures in 2011 to remodel two cafeterias at SONGS.[132] SCE explains:

> [t]here have been no upgrades or modifications made to the cafeterias since the early 1980s. Consequently the cafeterias have degraded, and do not meet expected levels of cleanliness and

---

[126] Ex. DRA-8, p. 11 citing SCE response to DRA data request 34, Q.5 (excerpt).

[127] Ex. SCE-2, Vol. 2, Part 2 workpapers at 126 and 132.

[128] Ex. SCE-2, Vol. 2 at 45-46; see also Appendix B, reference #45 at B-47.

[129] Id. at 46.

[130] Ex. DRA-8, p. 12, citing SCE response to DRA data request 34, Q.11 (excerpt).

[131] Ex. SCE-2, Vol. 2, Pt. 2 workpapers at 407, ln. 4.

[132] Ex. SCE-2, Vol. 2 at 29-30; see also Appendix B, reference # 19 at B-21.

> lighting to satisfy the needs of the present day worker. Because of food preparation, years of grease residue have built up on the ceilings and portions of the walls of the cafeteria. In addition, the equipment and appliances have withstood many years of repair and replacement parts are no longer available.[133]

DRA asked SCE to provide workpapers on options SCE considered regarding remodeling the cafeterias. SCE provided no workpapers, but did provide this explanation:

> [t]he remodeling design was based on the age of equipment and structures and was developed using the constraints of the existing footprint for both the serving and food preparation areas. Because of the limited space and work area in the SONGS cafeterias, SCE could not consider multiple remodeling options. Therefore, SCE considered one remodeling option. As discussed in SCE's testimony in SCE-02, Volume 2 on page 30, 'There have been no upgrades or modification made to the [SONGS] cafeterias since the early 1980s. Consequently the cafeterias have degraded…. In addition, the equipment and appliances have withstood many years and repairs and replacement parts are no longer available.' Because of the degraded condition of the cafeterias, SCE rejected the option of not remodeling them.[134]

SCE's capital cost forecast includes a 40% contingency for the remodel: [d]etailed plans, including design documents (diagrams/drawings), project plans, schedules, and Work Breakdown Structure (WBS), have not been developed at this stage, requiring a 40% contingency."[135]

Since the time of the data response justifying the 40% contingency, SCE has moved forward with a portion of the remodel: replacement of the ventilation and fire suppression systems at the largest of the cafeterias, for a cost of $332,000.[136] To the extent that there was a worker safety issue, it has been resolved by this work. SCE does not know when it will complete the additional work.[137]

SCE's justification for the remaining remodel work does not appear to be related to either safety or plant reliability. DRA recommends disallowance of the funding for the cafeteria

---

[133] Ex. SCE-2, Vol. 2 at 30, lns. 8-12.

[134] Ex. DRA-8, p. 13, citing SCE response to DRA data request 34, Q.6.

[135] Ex. DRA-8, pp. 13-14, citing SCE response to DRA data request 34, Q.16.

[136] Ex. DRA-57, SCE response to DRA data request

[137] 16 RT 2407:16-25, Bauder/SCE.

remodeling project, given what appears to be deficient project planning, an unknown commencement date for the remainder of the work, an excessive 40% contingency, and the lack of a safety or plant reliability rationale.

4.1.2. Palo Verde

SCE requests $38.0 million in capital expenditures for 2010, $36.7 million for 2011 and $30.4 million for TY 2012 for Palo Verde Nuclear Generating Station (Palo Verde).[138] DRA proposes to adjust SCE's requests to $35.8 million in 2010, $35.0 million in 2011 and $29.3 million in 2012 to disallow costs associated with SCE's share of the Component Design Basis Review documentation and the Nuclear Administrative and Technical Manual replacement.

SCE owns 15.8% of Palo Verde, and shares the costs of Palo Verde on an ownership percentage basis with the owners, including Arizona Public Service (APS), Palo Verde's operating agent. SCE appears to take no management responsibility for costs incurred at Palo Verde in the development of the Design Basis Review documents or the Nuclear Administrative and Technical Manuals. Instead, SCE states that "[a]s the operating agent for Palo Verde, Arizona Public Service (APS) develops and manages capital expenditures."[139] SCE treats its Palo Verde expenses as an automatic pass through to ratepayers, exercising minimal to no management control over APS.

Component Design Basis Review Documentation

SCE's testimony discusses deficiencies in the NRC-required Design Basis Review documentation:

> During an inspection of the plant, the NRC found a number of deficiencies between the Architectural Engineering (A-E) and Nuclear Steam Supply System (NSSS) vendors Design Basis documentation. A design basis identifies the specific engineering design parameters and the functions to be performed by a structure, system, or component of a facility. [footnote omitted] At Palo Verde this information is documented in a set of design basis manuals. In general, *it was discovered that Palo Verde's Design Basis Project (conducted in the early to mid-1990s) did not complete development of all planned Design Basis Manuals*."[140]

---

[138] Ex. SCE-2, Vol. 4 at 9, Table IV-1.

[139] Ex. SCE-2, Vol. 4 at 1.

[140] Ex. SCE-2, Vol. 4 at 19 (emphasis added).

In other words, the original Design Basis Project conducted in the early to mid-1990s was not complete. This is reflected in APS' own work authorizations for the new Design Basis Project:

> The Design Basis Project (conducted in the early to mid-1990's), did not complete development of all planned Design Basis Manuals (DBM's), nor did it complete the associated calculation re-verification effort. *The DBM's and re-verified calculations may not in all cases reflect the industries current best practices*.[141]

In fact, the Design Basis Project has been underway for over 5 years,[142] with SCE testimony showing prior capital expenditures of $3.7 million, a 2010 forecast of $1.3 million and a 2011 forecast of $0.7 million, for a total of $5.7 million.[143] SCE contends that "as the operating agent, APS is responsible for the development of the Design Basis manual."[144]

SCE is correct that the development of the Design Basis Review Documents belongs with the operating agent, APS, not SCE. APS had an obligation to complete the development of the Design Basis Manuals in the "early to mid-1990s," but, as discussed above, it failed to properly do so.

SCE's ratepayers should not be obligated to pay multiple times for the long overdue completion of the Design Basis Manuals. As a partial owner of Palo Verde, SCE has an obligation to oversee APS's performance and protect its ratepayers from APS inefficiencies.[145] SCE's failure to require APS to operate in an efficient and cost-effective manner should not be subsidized by SCE's ratepayers. DRA recommends an adjustment of $5.7 million to the capital expenditures for the Design Basis Manuals.

Nuclear Administrative and Technical Manual Replacement, Phase I

SCE's testimony addresses the need to replace the Nuclear Administrative and Technical Manuals at Palo Verde:

---

[141] Ex. DRA-58, Executive Summary at 1 (emphases added).

[142] Ex. DRA-58. The Executive Summary reflects that Phase I of the Design Basis Replacement was approved on September 20, 2006.

[143] Ex. SCE-2, Vol. 4, Table IV-2 at 10.

[144] Ex. DRA-8, p. 16 citing SCE response to DRA data request 37, Q.3 (emphasis added).

[145] Note that SDG&E took an active role in a prior SCE rate case (discussed in Section 4.1.1.2 above) in an effort to make SCE accountable for its management of SONGS.

> The NRC and Palo Verde internal audits group have identified instances of ineffective program administration and areas for potential improvement with regards to human behavior and performance. To address these concerns, Palo Verde is replacing the Nuclear Administrative and Technical Manual (NATM). The replacement of the NATM will improve technical specifications and reduce the likelihood of inoperable equipment, such as main steam isolation valves or station batteries, due to poorly defined maintenance procedures.[146]

For the replacement project, SCE's testimony shows prior capital expenditures of $0.8 million, a 2010 forecast of $0.9 million, a 2011 forecast of $1.0 million, and a 2012 forecast of $1.1 million, for a total of $3.8 million.[147] DRA obtained copies from SCE of the Palo Verde internal audit and NRC documentation mentioned above.[148] Both APS and the NRC identified "instances of ineffective program administration and areas for potential improvement with regards to human behavior and performance" that are the responsibility of the operating agent, APS. For the same reasons set forth above with regard to the Design Basis Review Documents, SCE's ratepayers should not be responsible for the manual replacement. DRA recommends an adjustment rejecting the inclusion in rates of $3.8 million for the NATM.

4.2. Generation – Coal Generation

SCE owns significant shares of two coal generation resources: the Mojave Generation Station (Mohave) and the Four Corners Generation Station (Four Corners). The Mohave plant is currently being decommissioned. The decommissioning should be complete during this GRC. SCE operates Mohave, and has a 56 percent ownership share in the plant. Arizona Public Service (APS) operates Four Corners and SCE has a 48 percent share (720 MW) of Units 4 and 5 of that plant. SCE's 50-year participation in Four Corners is scheduled to expire in 2016, absent any action or agreement with APS and the other project co-owners.

DRA does not dispute SCE's capital budget forecasts for coal, or the O&M forecast for Mohave. However, DRA recommends that SCE's Four Corners O&M forecast should be reduced by $4.829 million.

---

[146] Ex. SCE-2, Vol. 4 at 19.

[147] Ex. SCE-2, Vol. 4, Table IV-2 at 10.

[148] Ex. DRA-8, p. 17, citing SCE response to DRA data request 37, Q/A.4. SCE asserts a confidentiality claim over this data response.

4.2.1. Mohave

DRA does not dispute SCE's forecasts for Mohave given that all expenses at Mohave are subject to Mohave Balancing Account (MBA) treatment.[149] The MBA mandates that Mohave O&M funds shall not be redirected to other spending categories. The balancing account protects ratepayers from any imprudent funds shifting while the coal plant is being decommissioned. SCE forecasts $20.3 million in capital expenditures for its share of the decommissioning project at Mohave for 2010 and 2011.[150] The MBA also applies to the capital expenditures. On this basis, DRA does not oppose SCE's Mohave request.

4.2.2. Four Corners

DRA does not dispute SCE's capital expenditure forecasts for Four Corners, but does recommend that SCE's Four Corners O&M expense forecast be reduced by $4.829 million in Test Year 2012.

For cost forecasting purposes, the company provides two scenarios for consideration in this GRC: a "sale case" and a "decommission case".

In Application (A.)10-11-010, SCE presents a "Purchase and Sale Agreement" between SCE and APS, the operator of the Four Corners plant. Under the terms of the agreement, the forecast closing of the sale is October 1, 2012. The sale case assumes that SCE will contribute to the operation and maintenance of the facility on a "business as usual" basis, until the transaction closes.

The decommission case assumes that owners of the plant will somewhat reduce the historical maintenance and overhaul practices because the generating station will be nearing the end of its useful life. There would be reduced costs under the decommission case.

The sale case is $2.8 million greater than the decommission case. SCE justifies its funding request in this GRC pursuant to the sale case scenario. Consequently, DRA focused its review on this scenario.

DRA recommends a $4.829 million reduction in the O&M forecast for Four Corners. The first portion of the reduction, $4.257 million, is reflected in the non-labor FERC accounts 512, 513, and 514.[151] These expenses are related to the scheduled 2014 overhaul of Unit 5.

---

[149] Ex. SCE-2, Vol. 6 (Part 1), p. 65.

[150] Ex. SCE-2, Vol. 6 (Part 2), p. 50.

[151] Ex. SCE-17, Vol. 6 (Part 1), p. 4. The $4.257 number replaces $4.129 originally recommended in

However, under the sale scenario, which is forecast to occur in 2012, this 2014 overhaul would not be part of SCE's ownership obligation, since SCE would no longer be a co-owner of the plant. SCE's argument that the Four Corners sale to APS might not close is unpersuasive.[152]

The remaining $0.572 million of the Coal O&M adjustment is based on DRA's use of the 5-year recorded data for non-labor expenses for FERC Accounts 500, 501, and 502. In Rebuttal, SCE states "SCE agrees with DRA's proposal to use a 5-year average to forecast non-labor in accounts 500, 501, and 502, assuming the forecast includes overhaul costs."[153] Under the scenario that overhaul costs are still necessary, SCE estimates the reduction to accounts 500, 501, and 502 at $0.411 million.[154] There remains a $.161 million difference between DRA and SCE for this O&M category. However, DRA maintains its recommendation to disallow the forecast of overhaul costs, and hence, DRA continues to recommend a $.572 million adjustment.

4.3. Generation – Hydroelectric Generation

SCE's hydroelectric generation facilities (Hydro) are predominantly in the Big Creek (or Northern) system, which total 1,014 MW. The Eastern Region system totals 161 MW. The TY 2012 O&M request totals $57.6 million, which includes $9.6 million in future adjustments above the recorded 2009 base year amount which forms the basis of SCE's forecast. The Hydro capital expenditure forecasts for years 2010, 2011, and 2012, are $104.5 million, $93.1 million, and $95.5 million, respectively.[155]

DRA does not dispute SCE's capital budget forecasts for Hydro, but does recommend that SCE's O&M forecast be reduced by $6.840 million.

SCE's Hydro O&M expense request is significantly higher than average recorded figures. Based on SCE's data, DRA calculates the 2005-2009 average recorded annual expense to be $41.785 million (2009 $). Rather than relying on this data to form the basis of its forecast, SCE chose $48.0 million as its base forecast, evidently relying upon higher than normal 2009 recorded expenses. SCE then layers in several complicated "future adjustments" totaling $9.628 million to develop a TY forecast of $57.4 million. SCE explains that these future

---

Ex. DRA-9, p. 7.

[152] Ex. SCE-17, Vol. 6, (Part 1), p. 6.

[153] Ex. SCE-17, Vol. 6, (Part 1), p. 12.

[154] Ex. SCE-17, Vol. 6, (Part 1), p. 12.

[155] Ex. SCE-2, Vol. 7 (Part 2), p. 2.

adjustments come in seven distinct categories. The two most significant categories are discussed below.

The first future adjustment is termed "NERC and Other Agency Compliance." The cost forecast starts at $106,000 in 2010 and escalates to $2.714 million in TY 2012. Most of these costs are to cover additional personnel, 18 by 2012, to meet the increasing needs of the North American Electric Reliability Council (NERC) and other regulatory agencies. Edison reports that these new personnel include dispatchers, technicians, electricians and a librarian.

The second future adjustment by SCE is to "Optimize System Operations." The costs start at $224,000 in 2010 and jump to $1.264 million by TY 2012. This new cost category includes 10 additional personnel, including maintenance mechanics and a Program Manager. A non-personnel cost is for "Hydro Modeling Upgrade" to improve data gathering, forecasting, and grid operator requirements, according the company.

DRA has several concerns regarding SCE's proposed future adjustments to the Hydro O&M forecast. First, adding 28 new personnel, with the majority of the hires scheduled for TY 2012, represents a nearly 10 percent increase in total Hydro Division staffing. Many of these new hires seem to have tasks which should be covered within the current Hydro staff of dispatchers, technicians and electricians.

Second, the future adjustment categories not related to staffing increases, such as the maintenance activities (Flowline & Penstock and Powerhouse & Structure), are forecast to ramp up dramatically in TY 2012. SCE has not explained why these activities have sudden cost increases timed with the Test Year.

Given these concerns, DRA recommends that, to approve the Future Adjustments, the base year forecast should adjusted back to reflect historical average O&M costs. The base forecast is $41.785 million under DRA's approach. Adding SCE's future adjustments to DRA's base brings the total TY Hydro O&M to $50.591 million. This represents a $6.840 million reduction to SCE's request, and is appropriate given SCE's failure to justify the additional costs it proposes.

4.4. Generation – Gas-Fired Generation

SCE owns and operates the 1050 MW Mountainview Generating Station and four 49 MW peaking power plants. The Mountainview plant began operation in 2006, and consists of two modern combined-cycle units that are intended for efficient, load-following operation. The

peaking units are also of recent vintage; they were installed pursuant to a 2006 Commission Resolution.[156] These units are simple-cycle, quick start, and are intended for peak load operations to support system reliability.

SCE's gas generation O&M request totals $60.611 million for TY 2012. The capital budget request for 2010, 2011, and 2012 is $41.6 million, $7.8 million, and $22.0 million, respectively.[157]

DRA does not dispute SCE's capital budget forecasts for Mountainview, but recommends that its O&M forecast be reduced by $307,000.

Given that SCE's peaker forecast include costs for the McGrath Peaker, which is unlikely to be operational in the Test Year, DRA recommends that SCE's Peakers O&M forecast be reduced by $2.589 million and that its capital budget forecast for 2010 be reduced by $20.0 million.

4.4.1. Mountainview

DRA recommended two adjustments to SCE's Mountainview O&M forecast in its testimony. DRA recommended that SCE's proposed $307,000 incremental cost to cover additional compliance activities related to NERC standards be denied. DRA continues to make this recommendation. DRA has reviewed the workpapers that describe the duties for three new positions: two Program Managers and one Engineer. SCE states that these positions are allocated to Mountainview O&M as part of the $2.7 million overall impact that NERC compliance is forecast across the Power Production Department O&M expense. The activities forecast by SCE for three new positions (one Engineer and two program managers) should be absorbed into the remaining $2.4 million NERC compliance expense.[158]

The second, and larger, adjustment that DRA recommended in its testimony involves one-third of the cost for the scheduled 2015 Hot Gas Path Inspection (HGPI) (plus the Parts Use Tax). SCE forecasted the payment to General Electric under the Contractual Services Agreement to occur in late 2014. On Rebuttal, SCE agreed to move the 2014 forecast payment for the 2015 HGPI plus taxes to the 2015 GRC test year forecast.[159]

---

[156] Resolution E-4031, November 9, 2006.

[157] Ex. SCE-2, Vol. 08, p. 49.

[158] Ex. SCE-2, Vol. 8 workpapers, p. 20.

[159] Ex. SCE-17, Vol. 08, p. 1.

4.4.2. Peakers

4.4.2.1. Peakers O&M

DRA recommends an adjustment of $2.589 million for the Peakers O&M based on DRA's conclusion that the fifth Peaker (McGrath) will not be installed and operating by the Test Year. The McGrath peaker is not permitted and construction has not begun. The McGrath Peaker project would be located in the City of Oxnard. Since 2007, the City has mounted significant legal challenges to the company's attempt to site and construct this power plant. Currently, SCE is seeking a writ of mandate in Ventura County Superior Court to force the City to issue the final permits for construction to begin.[160] The hearing on SCE's writ, which will determine whether SCE can move ahead with construction, is scheduled for February 27, 2012.[161] Notwithstanding this hearing date, SCE has assumed pre-construction activities at the site to begin on January 2, 2012, to meet its in-service date of August 14, 2012.[162] While SCE claims that it is negotiating with the City and believes construction permits will be granted prior to the writ hearing date,[163] this seems improbable given the City's longstanding resistance to the McGrath Peaker being sited in the City. Given the uncertainty over the final resolution of the City's challenge, it would be imprudent to include McGrath-related costs in Test Year forecasts.

DRA's $2.589 million adjustment is based on 2009 recorded data, reflecting a full year of data for the four currently operating units. The adjustment represents a 29 percent decrease from SCE's TY forecast. The recorded 2009 data best reflects the O&M needs of the four operating peakers.

4.4.2.2. Peakers Capital Expenses

The SCE Peaker capital expenditure forecast for 2010, 2011, and 2012 is $31.8 million, $3.2 million, and $3.1 million, respectively.[164] The 2010 forecast includes $20.0 million for completion of the McGrath Peaker.[165] For the reasons described above, DRA recommends a disallowance of $20.0 million given the status of the McGrath Peaker project.

---

[160] Ex. SCE-17, Vol. 9, p. 3, lines 2-7.

[161] 14 RT 1935-1936, Phelan/SCE.

[162] 14 RT 1933-1934, Phelan/SCE.

[163] 14 RT 1956-1958, Phelan/SCE.

[164] Ex. SCE-2, Vol. 9, p. 15.

[165] Ex. SCE-2, Vol. 9, p. 15.

4.5. Generation – Project Development Division

DRA does not object to SCE's forecast for Project Development Division O&M.

4.6. Generation – Other

This section addresses the expenses SCE has forecasted for: (1) its recently established Solar Photovoltaic Program (Solar PV Program); (2) its Catalina Island generation; and (3) its recently established Fuel Cell Program.

DRA does not oppose SCE's capital budget forecasts for the Solar Photovoltaic Program (Solar PV Program). However, DRA recommends that SCE's Solar PV Program O&M Balancing Account be preserved.

DRA does not oppose SCE's Catalina Island O&M forecast. However, DRA recommends that its capital budget forecast for 2010 and 2011 be reduced by $2.885 million in each year.

DRA does not oppose either SCE's O&M or capital budget forecasts for its Fuel Cell Technology Program. However, DRA does oppose SCE's proposal to eliminate the Fuel Cell Program Memorandum Account. DRA proposes instead that the memorandum account be replaced with a one-way balancing account beginning January 1, 2012.

4.6.1. Solar PV

SCE's Solar Photovoltaic Program (Solar PV Program) was initially authorized in D.09-06-049. SCE forecasts capital expenditures for the Solar PV Program of $191.0 million, $197.0 million, and $203.0 million for 2010, 2011 and 2012, respectively.[166] DRA does not oppose these forecasts.

SCE has requested O&M funding for TY 2012 for the Solar PV Program activities. In support of this request, SCE's testimony explains:

- The Solar Photovoltaic Program is authorized funding pursuant to D.09-06-049.
- SCE *is not requesting additional capital beyond those amounts already authorized in D.09-06-049*.
- SCE *is requesting to include recovery of the associated solar photovoltaic program revenue requirement in the total general rate case revenue*

[166] Ex. SCE-2, Vol.10, p. 11.

requirement, consistent with how SCE recovers other utility-owned generation revenue requirements.[167]

SCE is essentially proposing to change the ratemaking treatment of the program originally authorized in D.09-06-049. SCE proposes to replace the one-way balancing account authorized in D.09-06-049 with traditional test-year GRC base rate revenue requirement treatment. DRA opposes this proposal, and strongly recommends that it be denied.

Decision 09-06-049 forecast Solar PV Programs expenditures of $41.31 million (2008 $) in O&M and $962.5 million (2008 $) in direct capital expenditures during the 2008 through 2014 program period.[168] By authorizing balancing account treatment for the O&M budget, the Commission ensured that SCE would recover the actual program expenditures, no more and no less. Based on recent information from SCE, the recorded program O&M expenditures through March, 2011, totaled $4.74 million, well below the pace of spending forecast in D.09-06-049. If that actual low spending trend continues, and the balancing account is eliminated, SCE could receive a revenue requirement well above program needs. Leaving ratepayers unprotected from this possibility is contrary to the ratemaking policy adopted in D.09-06-049.

Further, a recent filing by Edison provides strong evidence that SCE's O&M spending forecast in inflated. In its Petition For Modification (PFM) of D.09-06-049, dated February 11, 2011, SCE requested that the utility-owned generation (UOG) portion of the Solar PV Program be reduced from a 250 MW program to 125 MW program.[169] In support of the PFM, SCE states that the revisions requested in the PFM could result in approximately $300 million in savings to the revenue requirement on a present value basis.[170]

SCE's proposal to eliminate the Solar PV Program Balancing Account (SPVBA) should be denied. Balancing accounts are established for programs or activities distinct from traditional utility O&M activities and spending practices. SCE requested authority to establish the SPVBA.[171] There is no reason to eliminate the SPVBA at this time, particularly since the program may undergo a significant modification based on SCE's PFM, which would result in

---

[167] Ex. SCE-2, Vol.10, Summary page (emphases added); see also Ex. SCE-2, Vol.10, p.10.

[168] Decision Addressing A Solar Photovoltaic Program for SCE (2009) D.09-06-049, mimeo, p. 44.

[169] SCE Petition for Modification of D.09-06-049, A.08-03-015, Feb. 11, 2011, p. 2.

[170] SCE Petition for Modification of D.09-06-049, A.08-03-015, Feb. 11, 2011, p. 3.

[171] D.09-06-049, mimeo, p. 8

lower spending on the UOG portion of the program. The SPVBA should be maintained through this GRC cycle to ensure that the authorized funds are directed only to Solar PV Program activities.

4.6.2. Catalina Diesel

SCE provides electricity for Catalina Island through a system of diesel generators and micro turbines totaling 9.4 MW. Edison requests $4.730 million for TY 2012 O&M,[172] and $7.213 million, $12.110 million, and $1.060 million in capital expenditures for 2010, 2011, and 2012, respectively.[173] DRA recommends that SCE's Catalina Island O&M forecast be reduced by $0.140 million and that its capital budget forecast for 2010 and 2011 be reduced by $2.885 million in each year.

4.6.2.1. Catalina O&M Expenses

SCE forecasts $4.730 million for TY 2012 O&M expenses. DRA analyzed the three FERC accounts for Catalina, Accounts 548, 549, and 553 and recommended certain minor adjustments in its testimony.[174] The adjustments were based on reliance on the five-year historical average, or the 2009 recorded data. DRA's recommended total adjustment was $140,000, of which $87,000 was for Account 553. The $87,000 expense was for four power packs, where SCE spread the total cost of the packs over three years.

In its Rebuttal Testimony, SCE explained that various factors, such as vendor schedules, parts availability, load demands, and SCE maintenance schedules, affect the timing of the power pack installation process.[175] SCE's explanation is reasonable and DRA does not oppose the $87,000 power pack expense.

The remaining $53,000 of the recommended adjustment was based on the difference between historical expenses versus SCE's budget-based forecast. In its rebuttal testimony SCE represented that the $53,000 is based on a forecast for travel and miscellaneous expenses for two new employees, and is required based on the union contract.[176] Based on this representation,

---

[172] Ex. SCE-2, Vol.11, p. 4.

[173] The annual Catalina capital forecasts are derived from SCE's revenue requirement model.

[174] Ex. DRA-9, p. 11.

[175] Ex. SCE-17, Vol. 5, p. 2.

[176] Ex. SCE-17, Vol. 5, p. 3.

DRA does not oppose the $53,000 expense. Therefore, DRA does not oppose SCE's Catalina Island O&M forecast.

4.6.2.2. Catalina Capital Expenditures

SCE forecasts $7.213 million, $12.110 million and $1,060 million in capital expenditures for 2010, 2011, and 2012, respectively. DRA recommends two adjustments to the SCE forecasts in 2010 and 2011 to reflect that two projects included in the capital expenditures forecasts were previously approved in the 2009 GRC.

SCE requests $1.147 million to complete a Control Room Betterment Project. Edison admits that it requested and the Commission approved this project in the 2009 GRC.[177] The company states that other projects made it necessary to delay this project.[178] DRA believes it is inappropriate for SCE to ask the Commission to "re-approve" this project. Further, SCE now states that $1.406 million has been spent through June, 2011 on the Control Room Betterment Project.[179] This is clear evidence that the 2012 GRC should not include any capital expenditures for this project. SCE has now spent the money that was approved in the 2009 GRC. Therefore, DRA recommends that the Commission reduce SCE's forecasts for 2010 and 2011 by $573,500 per year.

SCE also requests $4.623 million to complete the Main & Garage Buildings Betterment Project on Catalina Island. Through June, 2001, SCE has spent $2.43 million on this project.[180] Similar to the Control Room Project, this project was approved in the 2009 GRC, but deferred. Edison states the deferral was related to a Settlement Agreement with the South Coast Air Quality Management District (SCAQMD).[181] This does not justify a second request to fund the same project. Further, over 50 percent of the project's capital budget approved in 2009 GRC has been spent. No further funding is justified for this project. DRA recommends an adjustment of $4.623 million, to be split evenly between 2010 and 2011, resulting in a disallowance of $2.312 million in both 2010 and 2011 for the Main & Garage Buildings Betterment Project.

---

[177] Ex. SCE-2, Vol. 11, p. 25.

[178] Ex. SCE-2, Vol. 11, p. 26.

[179] Ex. DRA-62.

[180] Ex. DRA-63.

[181] Ex. SCE-2, Vol. 11, p. 26.

4.6.3. Fuel Cells

SCE requests that currently authorized funding for the Fuel Cell Technology Program be maintained.[182] DRA does not oppose this request. SCE also requests elimination of the Fuel Cell Memorandum Account.[183] DRA opposes this request.

The Fuel Cell Program Memorandum Account (FCPMA) was established pursuant to D.10-04-028. As stated in SCE's Preliminary Statement to its tariffs, "The purpose of a Memorandum Account is to record all costs incurred by the Company for Specified Projects authorized by the Commission."[184] The Preliminary Statement also states that "Entries (of the revenue requirement) will be recorded in the FCPMA until such time as recovery of the Fuel Cell Program revenue requirement is included in a General Rate Case revenue requirement."[185] DRA agrees that this is the appropriate proceeding to now include the recorded costs of the Fuel Cell Technology Program within the authorized funding of $19.1 million capital and $8.9 million for O&M in the base rate revenue requirement.

However, as the program is a "Specified Project" as defined in the Preliminary Statement, and D.10-04-028 did not authorized spending above the amounts noted above, the FCPMA should be replaced with a one-way balancing account beginning in January 1, 2012. One-way balancing account treatment is consistent with D.10-04-028, which states that SCE "may file either a petition for modification or a separate application to seek recovery of the excess (spending over $19.1 million capital, $8.9 million O&M)."[186] This treatment will ensure that the ratepayer funds authorized for the program are not redirected to other activities or shareholder accounts.

5. Transmission and Distribution

5.1. T&D -- Policy

In this GRC, SCE's requests for Transmission and Distribution Business Unit capital expenditures and Operations and Maintenance expenses far exceed any request any utility has made in recent years, and come at a time of one of the worst economic periods in California's

---

[182] Ex. SCE-2, Vol. 10, pp. 33-38

[183] Ex. SCE-10, p. 35.

[184] SCE Tariff Books, Preliminary Statement "N", Memorandum Accounts, Sheet 1, available at http://www.sce.com/NR/sc3/tm2/pdf/ce91-12.pdf.

[185] Id., Sheet 58.

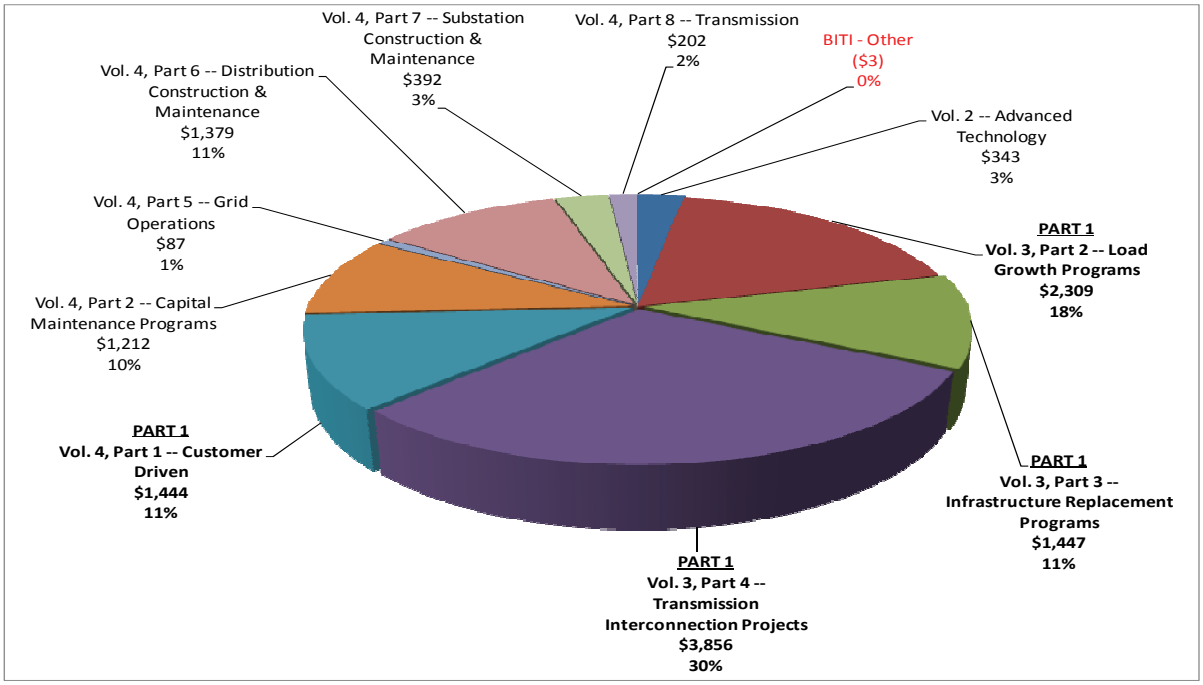
[186] Decision Authorizing Fuel Cell Projects (2010) D.10-04-028, mimeo, Ordering Paragraph 4c.

history. Oblivious to this, in SCE's Direct testimony, SCE proposes to spend a total of $12.668 billion on Transmission and Distribution Business Unit (TDBU) capital projects over the 5-year period, 2010 through 2014.[187]

Included in this $12.668 billion total are expenditures that will be litigated in Federal Energy Regulatory Commission (FERC) proceedings, therefore many of the dollars that make up the $12.668 billion are not discussed in this GRC. Nevertheless, it is important for the Commission to be aware of the entire capital obligation (CPUC plus FERC) that SCE is asking its ratepayers to bear.[188]

The chart below shows how SCE has subdivided its enormous TDBU capital expenditure request into numerous parts. The chart also shows the cumulative amounts that SCE has proposed spending for each part over the five-year period 2010 through 2014, as well as the percentage of the total expenditures each part constitutes.

SCE's TDBU Capital Expenditure Request
2010 – 2014 Forecast for Total Company
(in Millions of Direct Nominal Dollars)



[187] Ex. DRA-6, p. 2.

[188] Id.

The total of SCE's request of $12.668 billion also includes capital expenditures through 2014. Consistent with the Commission's decisions in SCE's last two GRCs, DRA examined SCE's proposed capital expenditures up to and including the 2012 Test Year.

On the TDBU expense side, SCE is asking for approximately $600 million (in 2009 dollars) for Operations and Maintenance expenses for the 2012 Test Year. This represents a $70 million (or 13.2%) increase over SCE's TY 2009 recorded expenses of $530 million (in 2009 dollars). SCE's Direct Testimony on TDBU O&M expenses alone numbered 5 volumes (public and confidential versions, with multiple parts) of testimony, and nearly 30 volumes of workpapers, sponsored by about 15 different witnesses.

The voluminous nature of SCE's testimony does not, however, mean that SCE has justified its forecasts. Despite the vast quantities of documents that were supposed to support SCE's requests for TDBU capital expenditures and O&M expenses, all too often the requests were based on conclusory statements with no documentation to support them, or forecast methods that were not fully explained, or were presented in a way that made it difficult, and on occasion, impossible, to track what SCE is asking for in this case against what it asked for, and received, in the last one.[189] This, in turn, necessitated numerous data requests to each of the numerous SCE witnesses, seeking explanations of what SCE should have provided in the first place.

In Rebuttal, SCE compounded these problems. Some of the "Rebuttal" testimony merely repeated the same generalizations made in direct testimony, or mischaracterized the testimony DRA and other parties had submitted. In some of the Rebuttal, SCE witnesses criticized DRA for not addressing SCE's budget-based forecasts for 2014, apparently unaware of the two previous SCE GRC decisions which held that:

> ..there is a fundamental problem with budget-based ratemaking that boils down to the fact that budgets are not always implemented as planned. In addition, no party other than SCE

[189] In SCE's 2009 rate case, SCE recorded costs in different FERC subaccounts than it recorded and presented in its 2012 case. For example, in 2009, SCE's FERC subaccounts looked like this: 570.200. In its 2012 case, no such subaccount exists (the subaccounts now look like this: 570.150) and it is nearly impossible to track and compare 2009 recorded costs with 2012 recorded costs because SCE failed to provide a roadmap correlating the 2009 subaccounting system with its 2012 subaccounting system. SCE admits that trying to track 2012 forecasted costs back to how SCE recorded the same costs in 2009 would be "very laborious" (see, 12 RT 1616:19, Trainor/SCE) and "difficult" (see, 12 RT 1618:19, Trainor/SCE).

> provided or analyzed detailed post-TY plan additional budget forecasts in determining increases. We cannot fault other parties for not recommending detailed PTYR capital budgets. As we have noted in past GRCs, analyzing such budgets for two additional years imposes a significant burden on resources.[190]

Implicit, and sometimes explicit, in SCE's Rebuttal were threats that adoption of forecasts for TDBU for anything less than what SCE is asking will endanger public and employee safety. For example, according to Rebuttal testimony sponsored by SCE's Executive Vice President for Power:

> We also initiated a new program in 2009 to systematically identify and replace underground vaults. These vaults house highly energized electrical equipment in a confined space, which makes them a difficult and dangerous place to work. A structurally compromised vault is not only a reliability issues, it also presents a significant safety challenge for our employees and the public. We currently have identified 135 structures for replacement. The engineering, planning and permitting work is ongoing. DRA's proposal would not let us complete these replacements for another seven years without counting a single additional structure that might be identified for replacement going forward...[191]

When asked if any of SCE's underground vaults had failed, SCE's Executive Vice President said: "Yes *they* have. I don't have the specifics, but *they* have failed."[192] When asked when SCE had found the failures in the vaults and what sort of failures she was referring to, the witness deferred the question to another SCE witness. That witness said that, in his 24 years at Edison, he was aware of one vault that failed this year in Long Beach. He was not aware of any "safety challenges to employees or the public," did not believe that anyone was hurt, and was not aware of any underground vaults that needed to be replaced immediately."[193]

In connection with employee safety, SCE's Rebuttal included the following: "DRA's Proposed Funding Levels Would Threaten Recent Improvements in Employee Safety"[194] The Rebuttal testimony continues, "[t]he costs of being safe are spread throughout our expense and

---

[190] D.09-03-025, p. 305; D.06-05-016, p. 306.

[191] Ex. SCE-18, Vol. 1, p. 8.

[192] 9 RT 935-936, Ziegler/ SCE, emphasis added.

[193] 13 RT 1766-1768, Stark/ SCE

[194] Ex. SCE-18, p. 7 lines 12-13.

capital expenditure estimates. This includes the costs incurred for safety team meetings, safety training, safety programs, and safety development."[195]

In SCE's TY 2009 GRC, SCE requested and was authorized $50 million for its Transmission and Distribution Training expenses. In that GRC, DRA objected to SCE's forecast as being excessive. In fact, it now appears from SCE's testimony in this GRC that, although SCE was authorized the full amount it requested for safety training for 2009, it actually spent about $10 million less for that purpose.[196]

Many of the issues in dispute in this case do not involve disagreements regarding facts. Instead, many of the topics involve matters of judgment. All too often, SCE claims its requests are based on subjective engineering or management judgment that is not borne out by any objective evidence. Another fundamental concern DRA has with the Application has to do with SCE's sudden desire to drastically increase its forecasted expense and capital expenditure levels in the 2012 Test Year.

Capital expenditure increases, deemed urgently needed by SCE, are forecasted for 2012. New capital categories, similarly deemed to be urgent, are created in 2012. DRA has questioned the urgency of many of these projects – if urgency is truly an issue, SCE should be required to explain to the Commission why it has waited until 2012 to institute these increases instead of incorporating them into the 2010 or 2011 capital forecasts. Similarly, SCE should be required to explain what precipitating events will cause these projects to become urgent, especially when the facilities being replaced performed satisfactorily the year before. Without these explanations, DRA recommends the Commission be very skeptical of SCE's claims of urgency.

Finally, there is SCE's recurring theme of "aging infrastructure" as a justification for the huge size of SCE's TDBU capital expenditure request. The Commission should examine this claim critically. The day a new car leaves the showroom, it begins to "age" and, theoretically, becomes less reliable. At what point should this car be replaced – 1 year, 2 years, 10 years, 20 years? The answer, of course, depends on many factors, including how well the vehicle has been maintained. Forty-year old Mustangs are commonly seen, and classic cars often look as pristine, and are as reliable, as the day they rolled off the assembly line. The point of all this is

---

[195] Ex. SCE-18, p. 7, lines14-16.

[196] Ex. DRA-5, pp. 9-10, footnote 15 citing D.09-03-025, p. 63 and Ex. SCE-3, Vol. 5, Part 2, pp. 43 and 48.

that SCE's simple claim that equipment is aging is not, by itself, sufficient to justify the need for large increases. The Commission should be acutely aware that just because SCE says its equipment is aging does not mean that reliability is being compromised or that drastic changes to the construction budget are warranted.

DRA has a mandate from the Legislature to seek "the lowest possible rate for service consistent with reliable and safe service levels."[197] For its review of this Application, DRA begins with the premise that SCE's current rates are just and reasonable. DRA also presumes that SCE is operating its system with current rates in a safe and reliable manner. With those assumptions in mind, DRA has examined the reasons SCE gives for its proposals in light of what SCE has asked for, and spent, in the past, and with reference to past Commission decisions that address the issues. The areas where DRA's recommendations differ from SCE's for TDBU costs are set forth below.

5.2. T&D – Advanced Technology

Operation and Maintenance Expenses - 560.260, 580.260, 588.260 & 580.261

SCE forecast $23.790 million for its Advanced Technology expenses: $20.977 million for Advanced Technology projects and $2.814 million for Research, Development and Demonstration expenses.[198] SCE developed its test year forecast utilizing a budget-based method.[199] The corresponding DRA estimate for SCE's Advanced Technology expenses is $15.254 million, which is $8.536 million less than SCE's forecast.

In regards to its Advanced Technology Organization[200] SCE states "because Advanced Technology was created in 2009, we do not yet have sufficient "apples to apples" historical information to permit the use of forecasting methodologies based on four or five years of historical data (for example, a five-year average methodology)".[201] DRA disagrees and utilized

---

[197] Public Utilities Code § 309.5

[198] Ex. SCE-3, Vol. 2, page 14 and 110.

[199] Ex. DRA-5, p. 139, citing DRA-SCE-063-TLG questions 13-b.2 and 9-c.1.

[200] SCE's Advanced Technology Organization (ATO) was created "by bringing together and pooling existing resources throughout the company" and the funding that was transferred into ATO from these other areas was authorized funding from previous rate cases. SCE did not provide historical recorded costs from the other areas that it pooled resources from in the creation of ATO for review, analysis and comparison with SCE's ATO historical expenses and test year forecast.

[201] Ex. SCE-3, Vol. 2, page 13.

averaging methodologies as well as SCE's 2009 recorded data as the basis for its estimates of SCE's Advanced Technology expenses.

560-260 – Operation Supervision and Engineering

SCE forecast $4.507 million for Sub-Account 560.260 (Labor of $2.539 million and Non-Labor of $1.968 million) for its Operation Supervision and Engineering expenses.[202] DRA utilized a three year average (2007-2009) as a basis for its forecast of $2.618 million for SCE's Sub-Account 560.260. DRA's estimate is $1.889 million less than SCE's forecast.

SCE's expenses increased by $4.039 million between 2005 and 2009, with 2009 recording the highest level of expenditures of $4.507 million. SCE states the following as the reason for the non-labor increase of $2.485 million between 2008 and 2009, "SCE commenced three important initiatives, each of which encompassed multiple projects and studies".[203] DRA requested additional information on SCE's work activities and its test year forecast.

DRA asked:[204]

> SCE's forecast includes an additional $0.799 million to add six additional positions in 2012 over 2009 to its AT organization. In 2009 SCE's labor increased by $0.716 million due to SCE adding additional positions.
>
> Provide the documentation that demonstrates specifically how SCE incorporated the salary savings from employee retirements during the historical years into its test year forecast for six additional positions.

SCE's response:

> As stated in testimony at page 13, lines 6-12, the Advanced Technology Organization (AT) was created in 2009. As such, use of historical information to permit forecasting future needs was not useful or representative of the real funding needs on a going forward basis. Therefore, we adopted a budget-based approach that used recorded and adjusted 2009 Test Year O&M expenses as the base. Using recorded expenses incorporated current costs and consequently incorporated any changes in labor expense from prior periods due to retirements.

---

[202] Ex. SCE-3, Vol. 2, page 23.

[203] The three initiatives and the associated costs that increased 2009 non-labor recorded adjusted expenses contributing to the 245.10% increase were SCE's development of its Smart Grid Strategy and Road Map of $0.248 million, a special study on the "impacts of large scale penetration of intermittent, renewable resources" of $1.948 million, and development of its Tehachapi Wind Storage project proposal for the U.S. Department of Energy of $0.104 million (Ex. SCE-3, Vol. 2, page 25).

[204] Ex. DRA-5, p. 142, citing DRA-SCE-063-TLG question 12-g.3

> We forecast O&M expenses for six (6) new positions using SCE CIP Salary Bands for the specific job type.

DRA asked:[205]

> SCE states that "other non-labor projects and related expenses were deferred to accommodate this specialized engagement of outside resources". Provide the documentation that explains in detail all the "other non-labor projects and related expenses" that were deferred.

SCE's response:

> SCE did not specifically track the projects that it deferred to accommodate the initial smart grid vision and strategy work. The following are representative projects from that period that did not move forward at that time: Switching and Transient Studies, Flexible Alternating Current Transmission System Applications in SCE, High Voltage Direct Current Modulation Using Positive Sequence Load Flow and Power Systems Outlook, Sagometer/CAT-1 Test, and Real Time Control for High Voltage Direct Current Modulation.

Based on SCE's responses, it has embedded funding from completed projects that can be allocated for test year activities. SCE utilized its 2009 recorded adjusted expenses of $4.507 million as its test year estimate for Sub-Account 560.260, stating, "We forecast that we will continue the level and types of activities pursued in 2009".[206] DRA takes issue with SCE's estimate. DRA considers SCE's "initiatives, each of which encompassed multiple projects and studies" and which caused recorded adjusted expenses to increase substantially by 245.10% over 2008 expense levels, as special and distinct one-time non-recurring projects that should be removed from the calculation of SCE's test year estimate, or at a minimum be averaged over the historical period to account for the large increases.[207]

Although SCE states it "will continue the level and types of activities pursued in 2009", SCE's testimony does not specifically identify any test year projects or activities that it plans on pursuing, nor does it demonstrate any detail on proposed calculations for test year projects to be reviewed, analyzed, and evaluated. SCE's level of support does not justify this continued level

---

[205] Ex. DRA-5, p. 142, citing DRA-SCE-063-TLG question 12-d.

[206] Ex. SCE-3, Vol. 2, page 25.

[207] SCE's Smart Grid Strategy and Roadmap initiative began in April 2009 and was completed in May 2010, its large scale Integration of Renewable Energy Resources initiative began in January 2009 and was completed in December 2009, and its proposal for the Tehachapi Storage project was completed and submitted by August 2009 (DRA-SCE-063-TLG question 12-c).

of ratepayer funding in Sub-Account 560.260. DRA is also concerned that SCE is double counting by requesting increased ratepayer funding for similar programs, projects and initiatives in Sub-Account 560.260, 580.260, 588.260 (Plug-In Electric Vehicles) 580.261 (RD&D)[208] and its Edison SmartConnect/Advanced Metering Infrastructure (AMI) proceeding.[209] SCE should have embedded funding in its historical expenses associated with closed and completed projects, and from authorized funding from related proceedings where SCE requested funding for similar activities as those recorded in Sub-Account 560.260. DRA's test year estimate of $2.618 million based on a three year average (2007-2009) is reasonable.

580.260 – Distribution Engineering and Planning

SCE forecast $11.955 million for Sub-Account 580.260 (Labor of $6.836 million and Non-Labor of $5.119 million) for its Distribution Engineering and Planning expenses.[210] DRA utilized a three year average (2007-2009) as a basis for its forecast of $8.375 million for SCE's Sub-Account 580.260. DRA's estimate is $3.580 million less than SCE's forecast.

SCE's expenses increased by $6.342 million between 2005 and 2009, with 2009 recording the highest level of expenditures of $11.254 million. SCE's expenses fluctuated between 2005 and 2008 with an average for the four year period of $6.267 million. SCE's expenses increased significantly by $4.658 million or by 70.62% between 2008 and 2009, from $6.596 million in 2008 to $11.254 million in 2009. The labor expense increase between 2008 and 2009 was due to SCE adding eighteen new positions[211] and its engineers charged more time

---

[208] Several of SCE's proposed RD&D projects included in its estimate of $2.814 million for Sub-Account 580.261 appear to be very similar to activities that are already funded in rates and additional funding would constitute double funding of these projects and would be a burden to ratepayers (i.e. Electric Transmission (Plug-In Hybrid Electric Vehicle), Energy Efficiency and Demand Response, Advanced Metering Infrastructure (AMI), Greenhouse Gas, Climate Change, etc.). See SCE's response to DRA-SCE-063-TLG question 13.a-2 for a list of the RD&D proposed projects.

[209] Decision Approving Settlement on SCE Advanced Metering Infrastructure Deployment (2008) D.08-09-039.

[210] Ex. SCE-3, Vol 2, page 27.

[211] SCE's test year forecast of $11.955 million for Sub-Account 580.260, which is part of its Advanced Technology forecast of $20.977 million, includes funding for twenty-four positions which is in addition to the eighteen new positions created in 2009. DRA notes that SCE's funding request for these positions are in addition to SCE's test year request for Sub-Account 588.260 with a forecast of $4.514 million, where SCE is also requesting funding for twenty-four more positions to add to its Advanced Technology Organization. SCE also requested funding for six positions in Sub-Account 560.260 with a forecast of $4.507 million. Overall, SCE is requesting ratepayer funding for an additional fifty-four (54) positions for its Advanced Technology Organization in the test year.

to this Sub-Account and recorded less to capital projects. SCE states the non-labor increases between 2008 and 2009, "was primarily driven by projects and studies related to accelerating the identification, evaluation and testing of advanced smart grid technologies" relating to the deployment of rooftop solar generation of $2.243 million, development of SCE's Smart Grid Strategy and Roadmap Document of $0.570 million, development of proposals for the Department of Energy of $0.312 million, and "external engagement activities" related to development of smart grid related activities of $0.519 million.[212]

DRA considers SCE's costs incurred in 2009 for evaluating and testing of specific technologies, special studies, and development and implementation activities, as mentioned above, which caused recorded adjusted expenses to increase substantially by 70.62% over 2008 expense levels, to be special and distinct one-time non-recurring projects that should be removed from the calculation of SCE's test year estimate, or at a minimum, be averaged over the historical period to account for the large increases. DRA asked SCE if the one-time costs for these projects have been removed. SCE stated the following:

> SCE did not adjust or remove the recorded expenses of activities from the historic record because we developed our Test Year forecast on a budget-basis and projected that the work performed in 2009 is similar and representative of the expected level of effort for the 2012 Test Year and beyond that will be required as part of the process of managing a dynamic and evolving portfolio of new technologies. While individual projects may be perceived as "one-time" expenses, they are actually representative of the forecast level of effort and expense of a continuous, disciplined, structured, customer-focused technology planning and evaluation process that will guide SCE's Smart Grid technology deployment into the future.

SCE did not remove or take embedded costs incurred for its special one-time non-recurring projects into consideration when it developed its forecast utilizing a budget-based method. SCE provided DRA with a spreadsheet that listed its proposed test year projects for Sub-Account 580.260.[213] The spreadsheets included brief descriptions and various assertions about the projects, expected benefits and lump sum cost estimates. SCE did not provide specific detail on each project for review and analysis or the basis for each estimate included in the

---

[212] Ex. SCE-3, Vol. 2, page 30.

[213] SCE's projects totaling $5.119 million were as follows: Customer Empowerment of $0.400 million, Home Area Network of $1.0 million, Workforce Safety & Effectiveness of $0.400 million, Renewables & DER Integration of $2.3 million, Grid Efficiency & Resiliency of $0.319 million, and Information & Connectivity of $0.700 million (DRA-SCE-063-TLG question 9-c-3.)

calculation of the costs. SCE did not provide a cost benefit analysis for any of the projects and there were no identifiable or calculated ratepayer benefits or savings.[214] SCE's level of support does not justify the continued level of ratepayer funding in Sub-Account 580.260.

The projects also appear to be similar to SCE's RD&D projects recorded to Sub-Account 580.261. DRA is also concerned that SCE is double counting by requesting increased ratepayer funding for similar programs, projects and initiatives in Sub-Account 560.260, 580.260, 588.260 (Plug-In Electric Vehicles) 580.261 (RD&D)[215] and its Edison SmartConnect/Advanced Metering Infrastructure (AMI) proceeding.[216] SCE should have embedded funding in its historical expenses associated with closed and completed projects, and from authorized funding from related proceedings where SCE requested funding for similar activities as those recorded in Sub-Account 580.260 to address its test year activities, including its proposed Home Area Network (HAN) activities.[217] DRA's test year estimate of $8.375 million based on a three year average (2007-2009) is reasonable.

580.261 – Research, Development and Demonstration

SCE forecast $2.814 million for Sub-Account 580.261 (zero for Labor and Non-Labor of $2.814 million) for its Research, Development and Demonstration (RD&D) expenses.[218] SCE's forecast of $2.814 million is an increase of $1.163 million or 70.44% over 2009 recorded expenses of $1.651 million. SCE requested continuation of its one-way balancing and utilized a

---

[214] Regarding ratepayer benefits and savings, on proposed projects see D.06-05-016 page 64. Also see DRA's discussion on Sub-Account 580.261 on SCE's RD&D projects below.

[215] Several of SCE's proposed RD&D projects included in its estimate of $2.814 million for Sub-Account 580.261 appear to be very similar to activities that are already funded in rates and additional funding would constitute double funding of these projects and would be a burden to ratepayers (i.e. Electric Transmission (Plug-In Hybrid Electric Vehicle), Energy Efficiency and Demand Response, Advanced Metering Infrastructure (AMI), Greenhouse Gas, Climate Change, etc.). See Ex. DRA-5, p. 144 citing SCE's response to DRA-SCE-063-TLG questions 13.a-2 for a list of the RD&D proposed projects.

[216] D.08-09-039. SCE mentioned in its response that it is requesting that its Edison SmartConnect (ESCBA) remain in operation until 2014 for recorded authorized costs (Ex. SCE-04, Vol. 1) See Ex. DRA-5, p. 147, citing DRA-SCE-063-TLG question 6-b.

[217] SCE's HAN activities were authorized funding in D.08-09-039 through the end of 2012 in a memorandum account. SCE's test year request for Sub-Account 580.260 included twenty-four positions and nine of those positions were to address HAN activities (HAN forecast of $1.0 million based on a three year amortization; the detailed breakdown and basis for the individual estimates included in the costs of the HAN activities were limited and insufficient). SCE has embedding funding to address these activities and DRA's forecast of $8.375 million for Sub-Account 580.260 based on a three year average is sufficient.

[218] Ex. SCE-3, Vol. 2, page 111.

budget-based method to calculate its test year forecast for its RD&D expenses.[219] DRA utilized a five year average (2005-2009) as a basis and forecast $1.977 million for SCE's RD&D expenses recorded in Sub-Account 580.261. DRA's estimate is $0.837 million less than SCE's forecast.

DRA does not take issue with SCE's request for continuation of its one-way balancing account for its RD&D.[220] DRA does take issue with SCE's forecast. SCE's forecast, which includes an increase of 70.44% over 2009 recorded adjusted expenses, is not justified. SCE's expenses have fluctuated between 2005 and 2009 averaging $1.977 million for the five year period (2005-2009) and averaging $1.709 million for the three year period (2007-2009). DRA's use of a five year average addresses the fluctuations in the historical expenses and takes into account SCE's "handling a large number of unknowns and variables" associated with its experimental RD&D projects.[221] SCE provided limited discussion on its RD&D projects. SCE provided one page of testimony in support of its RD&D forecast of $2.814 million.[222] DRA requested additional information on SCE's RD&D forecast.

DRA asked:

> SCE states it "will refund to ratepayers any under-expenditure with accumulated interest". SCE was authorized $1.600 million in its 2006 GRC and $2.229 million in its 2009 GRC. Provide the documentation that explains in detail and demonstrates if SCE has refunded to ratepayers the under-expenditure for 2007 and 2009. Provide the specific accounts that demonstrate the refund to ratepayers and all supporting documentation regarding the refund.

SCE's response:

> The attached SCE Advice Letter gives a detailed explanation of the disposition of remaining funds at the end of the 2006 rate cycle (2008). RD&D expenditures are not as predictable as capital or O&M expenditures. RD&D is experimental by its very nature, and portions of projects may require further research and development before a project can proceed. In some cases, a technology breakthrough can significantly alter (for the positive and negative) a project's scope and schedule. Contracting for and managing RD&D, therefore, requires handling a large number of unknowns and variables.

---

[219] Ex. DRA-5, p. 148 citing DRA-SCE-063-TLG question 13-b.2.

[220] Ex. SCE-3, Vol. 2, page 110.

[221] Ex. DRA-5, p. 149, citing DRA-SCE-063-TLG question 13-c.

[222] Ex. SCE-3, Vol 2, page 110. SCE provided one page of testimony on its RD&D forecast and another page showing its historical expenses (2005-2009) in Figure V-25 on page 111.

DRA requested detail on the scope of SCE's "experimental" RD&D projects, the calculation of each project, and the basis for the calculation of each estimate included in the proposed projects of $2.814 million.[223] SCE provided several documents associated with its RD&D projects that included general descriptions and scope of projects, lump sum costs estimates for each project lacking calculated ratepayer benefits, and for the most part, included completion dates prior to the 2012 test year. SCE's response is insufficient and does not justify additional ratepayer funding in 2012, and with completion dates prior to the 2012 test year, SCE should have embedding funding in its historical expenses to address these RD&D activities.[224] In SCE's 2009 GRC[225] and its 2006 GRC, the Commission expressed concern over the lack of justification provided by SCE for its Research, Development and Demonstration forecast.

The Commission stated the following:[226]

> In 2003, SCE spent $1,169,000 for RD&D in this account. For the test year, it proposes a significant increase of $3,031,000 or 259%. We are not convinced that SCE's requested increase is reasonable or necessary. In its direct testimony, SCE provides a brief description of its current RD&D efforts in six different areas in which it expects to utilize its requested funding. SCE includes general descriptions of the programs within each area and the budget for that area. Such support is insufficient to justify a 259% increase in spending. SCE has provided no detailed information, by project or program that supports its $4,200,000 budget. We have no way of knowing what the scope or cost is for programs or projects that have been historically funded or what the scope or cost is for new existing programs or projects that are budgeted for the test year. Even by its general descriptions, it is difficult to determine what the existing, continuing and new activities are. There is insufficient support to justify SCE's proposed increase in the authorized spending level. In the absence of such justification, DRA's proposal to use an average of the last three recorded years is reasonable and will be adopted, resulting in a test year forecast of $1,600,000 for Account 580.500.

---

[223] Ex. DRA-5, p. 150, citing DRA-SCE-063-TLG question 13-a.1 SCE's response was marked "Confidential".

[224] DRA noted that several of SCE's proposed RD&D projects included in its estimate of $2.814 million appeared to be very similar to activities that are already funded in rates and additional funding would constitute double funding of these projects and would be a burden to ratepayers (i.e. Electric Transmission (Plug-In Hybrid Electric Vehicle), Energy Efficiency and Demand Response, Advanced Metering Infrastructure (AMI), Greenhouse Gas, Climate Change, etc.). See Ex. DRA-5, p. 150, citing SCE's response to DRA-SCE-063-TLG questions 13.a-2 for a list of the projects.

[225] D.09-03-025 page 77-78.

[226] D.06-05-016 page 80-81.

Similar to SCE's TY 2006 GRC and its TY 2009 GRC,[227] SCE lacks sufficient justification for its RD&D projects included in its TY 2012 GRC. DRA's use of a five year average (2005-2009), as the basis of its estimate of $1.977 million for the test year forecast provides SCE with $325,000 more than its 2009 recorded adjusted expenses. DRA's estimate is also more than the three year average (2007-2009) of $1.709 million and is a reasonable test year estimate for Sub-Account 580.261.

588.260 – Plug-In Electric Vehicle Readiness

SCE forecast $4.514 million for Sub-Account 588.260 (Labor of $2.789 million and Non-Labor of $1.725 million) for its Plug-In Vehicle Readiness expenses.[228] SCE's forecast of $4.514 million is an increase of $2.230 million or 97.64% over 2009 recorded adjusted expenses of $2.284 million. DRA utilized SCE's last recorded year as a basis for its forecast of $2.284 million for SCE's Sub-Account 588.260. DRA's estimate is $2.284 million less than SCE's forecast.

SCE's request is excessive and is not justified. SCE provided limited support for review, evaluation and analysis to justify an increase of 97.64% in the test year.[229] SCE states its "PEV-Readiness program did not exist prior to 2009. Accordingly, no analysis of historical costs is possible".[230] SCE's forecast for Sub-Account 588.260 includes additional funding for twenty four full-time equivalent positions.[231] SCE "expects 73,000 PEVs to utilize charging infrastructure in SCE's service territory by 2014".[232]

---

[227] D.09-03-025 page 77-78.

[228] Ex. SCE-3, Vol. 2, page 31.

[229] SCE provided a brief one page spreadsheet that included a list and associated costs for the proposed positions. SCE also included line items for contract costs, travel expenses, studies, and dues. SCE did not provide verifiable support or the basis for the individual estimates included in the calculations for review, evaluation or analysis. SCE also provided a flowchart of work activities for PEV activities that will end in 2010 and for work that will be added or performed in 2011. SCE did not provide a detailed breakdown of the associated costs for the activities and the basis for the estimates for review and analysis.

[230] Ex. SCE-03, Vol. 2, page 31. DRA notes that SCE incurred costs for studies associated with electric plug-vehicles in 2007 recorded in Sub-Account 580.260 (Ex. SCE-03, Volume 2, page 27).

[231] SCE's test year forecast of $4.514 million for Sub-Account 588.260, which is part of its Advanced Technology forecast of $20.977 million, includes funding for twenty-four positions to address Plug-In Electric Vehicle Readiness activities. DRA notes that SCE's funding request for these positions are in addition to SCE's test year request for Sub-Account 580.260 with a forecast of $11.955 million, where SCE is also requesting funding for twenty-four more positions to add to its Advanced Technology Organization. SCE also requested funding for six positions in Sub-Account 560.260 with a forecast of $4.507 million. Overall, SCE is requesting ratepayer funding for an additional fifty-four (54) positions

DRA agrees with SCE's assessment that there is "significant uncertainty about the pace of vehicle adoption by SCE's customers exists, and the number of PEVs on the road will likely remain small in the early years".[233] Based on this "significant uncertainty", increasing ratepayer funding for these projects would be inappropriate.[234] Furthermore, SCE's assertions that it expects an estimate of 73,000 PEVs utilizing its charging infrastructure by 2014, does not appear to be reasonable.[235]

DRA requested additional information from SCE on its forecast for Sub-Account 588.260 relating to its electric vehicles, especially since SCE was authorized some funding for electric vehicles in its TY 2009 GRC.[236]

DRA asked:[237]

> In SCE's 2009 GRC (D.09-03-025, pages 114-118), SCE was authorized $2.33 million and an additional $1.0 million, over its 2006 recorded expenses, for studies, research, and planning related to electric vehicles and other projects related to Electric Transportation which appear to be similar to SCE's request in its 2012 GRC relating to electric vehicles. Provide the documentation that demonstrates in detail how SCE incorporated the $3.3 million, which is still embedded in its historical expenses (DRA notes that some of the projects have been completed) in to its test year forecast.

SCE's response:

---

for its Advanced Technology Organization in the test year.

[232] SCE mentions Chevy and Nissan as companies that will have major commercial releases of PEVs by the end of 2010 as support for its forecast of PEVs (SCE03-Volume 2, page 16). DRA notes that the sales have been low. DRA discovered that Chevrolet sold 1,210 Volts as of the end of March 2011 and Nissan sold 452 "Leafs" as of the end of March 2011 (Information from article in Chicago Tribune, "Electric Vehicles: Are We There Yet").

[233] Ex. SCE-3, Vol. 2, page 16 and 17.

[234] DRA is skeptical whether a large number of ratepayers will be rushing out to purchase electric-plug in vehicles in the near future. A survey by the Consumer Reports National Research Center on concerns regarding electric vehicles found 66% of consumers said the price was too high, 60% said there was inadequate refueling or recharging infrastructure and 58% said there was a limited driving range for the electric vehicles (Chicago Tribune, "Electric Vehicles: Are We There Yet).

[235] Based on a J.D. Power and Assoc. study (Drive Green 2020: More Hope than Reality) issued in October 2010, the number of commercial sales of electric vehicles is expected to be limited for 10 years due to the fact that the infrastructure required to support an increase in electric vehicles is not available.

[236] In regards to the funding it was authorized in its TY 2009 GRC for electric vehicles, SCE states "While this PEV Readiness program is related to, and builds upon, ATO's technology identification and evaluation program results from prior years, efforts, the PEV Readiness effort is itself a new, separate and distinct body of critical work activity" (DRA-SCE-063-TLG question 8-e).

[237] Ex. DRA-5, p. 155, citing DRA-SCE-063-TLG question 10-e.

> As previously discussed in our response to question 8c of this data request, the $3.3 million authorized increase provided for the following activities: electric vehicle safety studies, electric transportation customer outreach, PHEV studies to assess environmental & economic impacts, vehicle to grid (V2G) and energy storage studies, and truckstop & seaport electrification testing & evaluation. These activities are ongoing within the Advanced Technology organization, and were used to develop our Test Year forecast on a budget requirement basis. Please note that the $3.3 million referenced in this question is not related to the current or forecast spending for the PEV Readiness Program in FERC sub-account 588.260. The PEV Readiness program is a new organization created in 2009 to meet the requirements of the Commission's 2009 AFV OIR. Please find a discussion of the referenced funding and how it is incorporated into SCE's test year forecast in the response to Question 8a and 8e of this data request.

DRA asked:[238]

> In SCE's response to DRA-VERBAL-30 SCE states "In D.09-03-025 (pages 116-118) the Commission approved SCE's 2009 GRC funding request for electric transportation outreach efforts, studies to assess environmental and economic impacts of Plug-in Hybrid Electric Vehicles (PHEVs), and studies to evaluate vehicle to grid (V2G) energy storage. These activities occurring during the 2009 GRC are different than the types of activities SCE has included in the 2012 GRC, which are to support the commercial launch of PEVs in late 2010". Provide the documentation that explains in detail and demonstrates why SCE is not able to reallocate the funds from completed projects or projects that were not implemented during the 2009 GRC cycle that were authorized in the 2009 GRC to proposed projects in the 2012 GRC that relate to electric vehicles. Provide the status of all projects SCE proposed and received funding for in the 2009 GRC relating to Plug-in Hybrid Electric Vehicles.

SCE's response:

> Please see response to part (e) of this question.

SCE's responses are insufficient and do not provide a reasonable explanation for why its embedded funding from closed or completed projects associated with its electric vehicles cannot be used for its proposed test year activities. Based on the limited amount of support and historical expense data provided by SCE, additional funding over SCE's 2009 recorded expense levels of $2.284 million for Sub-Account 588.260 should be denied.

Capital Expenditures

According to SCE, its Advanced Technology group was created in 2009 by bringing together the experience and talents of personnel from diverse groups within SCE. The groups

[238] Ex. DRA-5, p. 155, citing DRA-SCE-063-TLG question 8-f.

were: the engineering advancement group from the Transmission and Distribution Unit, the Electric Transportation group from the Customer Service Business Unit, and the home-area-network and advanced customer applications teams from the Edison SmartConnect[tm] program.

SCE says the primary mission of the Advanced Technology group is to "identify, develop, demonstrate, and evaluate an evolving portfolio of new technologies to create a smarter, more robust, resilient and efficient power grid."[239] SCE says it is "essential" that SCE integrate these technologies into its existing electricity infrastructure if it is to balance the rapidly changing and diverse environmental and energy policy objectives with satisfying its customer's energy needs and expectations for reasonable rate impacts.[240]

SCE's historical capital costs for Advanced Technology went up in 2006, 2008 and 2009, but down in 2007. The lowest amount SCE spent was $11.5 million in 2007, the middle year of the historical data period, and the highest year was 2009 at $25.3 million. No other year was even close to the capital expense booked in 2009. During 2010, costs went down to $22.9 million.

During 2009, when SCE capitalized $25.3 million for Advanced Technology projects, it was authorized to recover in rates a return on $53.4 million. For 2010, SCE forecasted Advanced Technology capital expenditures of $40.3 million, but as noted above, spent about $17 million less. For 2011 and 2012, SCE is seeking over $60 million a year of Advanced Technology capital expenditures.

DRA's recommendations in Advanced Technology capital expenditures can be broken into three areas. In the first area are those SCE expenditure forecasts that DRA accepts. In the second area are forecasts for projects that the Commission authorized for SCE in its last GRC, but SCE did not fund, and which DRA recommends the Commission reject in this GRC. The last area includes forecasts which SCE fails to justify adequately and which DRA recommends be rejected. The forecasts DRA disputes and the items DRA recommends be rejected are discussed below.

---

[239] Ex. SCE-3, Vol. 2, p. 5, lines16-17.

[240] Ex. SCE-3, Vol. 2, p. 5, lines 2-20

5.2.1. Circuit Automation

SCE says the primary purpose of its Circuit Automation Program is to automatically restore power to customers after outages caused by faults.[241] In its Direct testimony, SCE asked for a total of $14.2 million in constant 2009 dollars for the 2010, 2011 and 2012 expenditures for the Circuit Automation program.[242] DRA accepted that $14.2 million total over the three year period, using SCE's actual 2010 expenditures of $11.5 million plus an additional $1.35 million in 2011 and again in 2012.[243]

In Rebuttal, SCE argues for a new, and higher, expenditure level totaling $22.9 million in nominal dollars for the years 2010, 2011 and 2012.[244] Nowhere in SCE's Rebuttal does SCE explain why its original forecast of $14.2 million for years 2010, 2011 and 2012 shot up to $22.9 million, even allowing for the difference between constant 2009 dollars and nominal dollars. Nor does SCE offer any evidence that ratepayers would receive some added benefit for the added cost.

DRA continues to recommend ratepayer funding of no more than $14.2 million for this project for years 2010, 2011 and 2012.

5.2.2. Smart Distribution Transformers

According to SCE's Direct testimony, starting in 2012, SCE will begin a new Smart Distribution Transformer program to proactively manage its fleet of approximately 700,000 distribution transformers. SCE says it currently has limited ability to predict failure accurately and can only estimate failure based upon a transformer's age. Generally, SCE replaces transformers after failure occurs. SCE claims that, with the Smart Distribution Transformer program, SCE will include a temperature monitor and communication device with new equipment. SCE "believes that Smart Distribution Transformers will provide it with the capability to proactively manage its fleet of distribution transformers."[245]

SCE's Direct testimony provides no independent, verifiable basis for this belief. SCE did no cost benefit analysis to allow the Commission to determine if the benefits to ratepayers would

---

[241] Ex. DRA-7, p. 9 citing Ex. SCE-3, Vol. 2, p. 36, lines 18-20.

[242] 11 RT 1242-1243, Kim/SCE.

[243] Ex. DRA-7, p. 9.

[244] 11 RT 1245, Kim/ SCE.

[245] Ex. SCE-3, Vol. 2, p. 45, lines 1-11.

outweigh the costs. If an engineering study was performed, it was not included in SCE's testimony either. There is no historical data relating to Smart Distribution Transformers to use as a basis of comparison, and no law or regulation requires SCE to adopt this program.

In fact, there is no evidence at all to support adopting this program at this funding level at this time. DRA recommends zero funding for SCE's Smart Distribution Transformer capital expenditure request.[246]

5.2.3. Distribution Efficiency Enhancement Project

SCE says its Distribution System Efficiency Enhancement program consists of servicing and expanding the NETCOMM wireless communication system. SCE says the NETCOMM system provides the radio communication infrastructure to remotely monitor and control SCE's distribution automation devices.[247]

SCE is projecting substantial increases in this area, though its actual costs have been coming down. SCE's highest capital expenditures occurred in 2006, and its lowest in 2009. In 2009, SCE spent approximately $3.9 million for the Distribution System Efficiency Enhancement Project; though it was authorized funding in the amount of $4.9 million for it.[248]

DRA recommends that the Commission limit SCE's recovery from ratepayers in 2011 and 2012 to the 2005 through 2009 five-year average, which is $4.3 million

In Rebuttal, SCE argues that "DRA's proposal to use a five-year average is inappropriate here. An average is applicable only if the costs fluctuate from year to year or if the drivers are beyond the utility's control." As support for this argument, this SCE witness relies, as do many other SCE witnesses, on a 1989 Commission decision resolving a PG&E rate case.[249]

DRA considers D.89-12-057 to provide guidance, rather than some black letter law that must be automatically applied. In some circumstances, a five-year average may be appropriate even if costs do *not* fluctuate from year to year, or the drivers *are* within the company's control. Here, however, SCE's costs did fluctuate, according to SCE's own testimony.[250]

---

[246] Ex. DRA-7, pp 9-10; 11 RT 1253-1254, Kim/ SCE.

[247] Ex. SCE-3, Vol. 2, p. 48, lines 3-8.

[248] Ex. DRA-7, p. 12 citing SCE response to DRA-SCE-171-MKB Q/A 1.

[249] Ex. SCE-18, Vol. 2, p. 47 citing D.89-12-057.

[250] 11 RT 1256, Kim/ SCE.

DRA continues to recommend ratepayer funding of no more than $4.3 million for this project in 2011 and 2012.

5.2.4. Integrated Smart Distribution

SCE says it will begin deploying an Integrated Smart Distribution program in 2012. SCE says the new program will have three main sub-projects (1) a new circuit design that will serve as the foundation of a self-healing distribution grid; (2) a new project that will address intermittent resources like wind and solar; and, (3) large distribution support devices (including energy storage).[251] SCE is seeking $15.1 million in capital expenditures associated with this program in TY 2012.

In SCE's last GRC, SCE did not specifically request funding for this Integrated Smart Distribution program,[252] and during the period 2005-2010, SCE has had no capital expenditures for it. Thus, there is no historical information to use as a comparison for the reasonableness of its forecast.

In its testimony, DRA recommended no ratepayer funding of the Integrated Smart Distribution program at this time. The program is not required, and SCE has not demonstrated that its benefits will outweigh its costs. Prior to receiving funding for any program, good management practice and procedures should include some sort of cost/benefit study, or a test program to find out the actual costs and benefits. SCE has failed to take even these basic steps and has not justified making ratepayers fund such a program.[253]

In Rebuttal, SCE says it proposes this project because "… we need to begin addressing the challenges associated with operating a grid that is made more complex by policy goals." SCE's testimony is filled with "broad discussions," but nowhere in its testimony does SCE include any sort of study that would show the Commission how even one of SCE's particular projects will meet policy goals. Nor is there anything to show that the approaches SCE proposes are the best, most cost efficient for ratepayers.

DRA continues to recommend zero ratepayer funding for this program at this time.

---

[251] Ex. SCE-3, Vol. 2, pp. 50-51, lines 1-15.

[252] Ex. DRA-7, p. 13, citing Response to DRA-SCE-172-MKB Q/A 1.

[253] Ex. DRA-7, pp. 12-13.

5.2.5. Substation Automation

SCE says it will begin deploying an advanced Substation Automation program it calls "Substation Automation-3" in 2012. According to SCE, Substation Automation-3 will involve replacing and upgrading substation networking and communication equipment to support the International Electrotechnical Commission (IEC) Communication protocol. SCE says this protocol will become the industry standard for distribution and substation automation, and will be critical in bringing about a completely automated distribution system.[254] SCE is seeking $2.8 million in capital expenditures associated with this program in TY 2012.

In its Direct testimony, SCE sets out the history of its Substation Automation Programs.[255] The first Substation Automation design standard was a proprietary standard. The second was a somewhat more open standard and SCE's proposed Substation Automation-3 program is based on a "new international standard IEC 61850."[256]

None of the programs SCE has chosen in the past for Substation Automation has actually been required, and the one SCE has selected as Substation Automation 3 is not required either. In response to a data request asking for the justification for this proposal, SCE stated that its "Engineering/ Procurement/ Design allocations [are] based on engineering judgment," and the "Quantity based on project management estimates." SCE used the same justification for both A/AA & B sub stations.[257]

As DRA observed in its testimony, when SCE identifies a quantity or price being based on engineering or management judgment or estimates that is where the supporting documentation trail ends.[258] In Rebuttal, SCE argues that "Per the Rate Case Plan, [engineering and management judgment] are permissible bases for a forecast."[259] SCE's citation for this statement is taken from a Commission decision that relates to whether or not a justification is considered a "deficiency" for purposes of accepting a Notice Of Intent to file a rate case application. Almost anything can be the basis of a forecast, but that does not mean that the

---

[254] Ex. SCE-03, Vol. 2, pp. 60-61, lines 1-5.

[255] Ex. SCE-03, Vol. 2, p. 61, line 2.

[256] Id.

[257] Ex. DRA -7, p. 14 citing Response to DRA-Verbal-064, dated 03/14/2011.

[258] Ex. DRA-7, p. 14.

[259] Ex. SCE-18, p. 59.

unsupported conclusion of an unidentified individual meets the standard of substantial evidence in light of the whole record necessary to support a Commission finding in the final decision.

SCE provided no analysis to show that the benefits of this program to ratepayers outweigh the costs and SCE has included nothing in its testimony to support the claim that this latest program will be compatible with SCE's existing infrastructure.[260] SCE's testimony that it has provided "the essence"[261] of the study is hardly the same thing.

The Commission has nothing to rely on to show that this proposed Substation Automation program is the best, most efficient way to achieve a completely automated distribution system. Nor does the Commission have any assurance that SCE is not going to be back in the next GRC asking for more ratepayer money for a Substation Automation-4 program. DRA continues to recommend zero ratepayer funding for this program at this time.

5.2.6. Distribution Management System

SCE says that, under its Advanced Technology programs, a wide range of field devices will be equipped with communication and automated control and operational capacity. According to SCE, a functional smart distribution grid is needed to integrate operation of these devices. SCE says the Distribution Management System is the answer that will provide the centralized computing system necessary to gather data from these various distribution automating programs, and facilitate automated operation and control of the distribution system.[262] SCE is seeking $3.9 million, $10.6 million, and $7.5 million in capital expenditures associated with this program in 2010 through TY 2012 respectively.[263]

When DRA asked SCE to provide the justification for the forecasts for this system, SCE stated that the unit cost basis for "Labor, PAMM IM Charges, [and] Budgeted OH" were estimated "based on management judgment."[264] As discussed in testimony, DRA considered SCE's unsupported claim of "management judgment" inadequate to justify ratepayer funding.

---

[260] Moreover, there seems to be some inconsistency between what, exactly the project *is*. In Rebuttal , SCE says "this project will provide a long-term solution that will be compatible with our existing automation infrastructure," but five lines later, SCE describes it as a "foundational project." (Ex. SCE-18, Vol. 2, p. 55, lines 14-15 and 20-21.

[261] 11 RT 1268, Kim/SCE.

[262] Ex. SCE-3, Vol. 2, p.66, lines 1-8.

[263] Ex. SCE-3, Vol. 2, p. 71, Figure IV-17.

[264] Ex. DRA-7, p. 15, citing Response to DRA-Verbal-064, dated 03/14/2011.

This program is not required by statute or regulation,[265] and SCE has not prepared any cost benefit study for it.[266] In SCE's last GRC, SCE requested and was authorized to recover $3.0 million for this system in 2009. It spent none of that funding in 2009 for the purpose for which it was granted. In 2010, SCE says it incurred $7.73 million in capital expenditures for the Distribution Management System project.[267] Yet, so far, this Distribution Management System is not gathering data from any devices at all.[268]

In light of the funding SCE has received for this project in the past, the fact that the spending SCE has made to date has not achieved the stated purpose of the project, and the lack of specific information showing that ratepayers will receive any benefit from this program that justifies its costs, DRA continues to recommend no additional ratepayer funding in this rate case.

5.2.7. Outage Information

SCE says its Outage Information project is a new program that will take advantage of existing capabilities of SCE's SmartConnect[tm] program to provide enhanced information about customers' outages to SCE's service crews and dispatchers.[269] When DRA asked SCE to provide the justification for the forecasts for this system, SCE said stated that its "Internal cost estimate [is] based on engineering judgment."[270] DRA considers SCE's unsupported claim of "management judgment" inadequate to justify ratepayer funding.

This program is not required by statute or regulation.[271] If SCE did any sort of cost benefit analysis of the project, or an engineering study showing that the project will achieve the ambitions SCE has for it, SCE has not provided them.

In SCE's last GRC, SCE did not specifically request funding for an Outage Information program,[272] so there is no historical data to provide any basis of comparison between what SCE is projecting and actual spending.

---

[265] Ex. DRA-7, p. 15

[266] Id.

[267] Ex. SCE-18, Vo. 2, p. 59.

[268] Ex. DRA-41.

[269] Ex. SCE-3, Vol. 2, p.71, lines 3-6.

[270] Ex. DRA-7, p. 16.

[271] Id.

[272] Id.

In light of all this, DRA continues to recommend no ratepayer funding for this program.

5.2.8. Phasor Measurement & Wide Area Situational Awareness

SCE says its proposed Phasor Measurement & Wide-Area Situational Awareness System program will provide electric system operators with previously unavailable information about the operating status of the bulk power system. According to SCE, this information will allow operators to better manage the region's transmission system and make the *critical* decisions necessary for pre-empting catastrophic electric system failures.[273] In this GRC, SCE is asking for a total of approximately $41 million for this program for the years 2010, 2011 and 2012.

In SCE's last GRC, SCE requested $34.0 million over the period 2009-2011 for a Phasor Measurement & Wide-Area Situational Awareness System program. Of that, SCE said $13.0 million was "… applicable to 2009 to implement a system that will give its system operators a direct indication of transmission system stress, and how close to the margins SCE is operating from system instability and potential system failure."[274] In the TY 2009 GRC, SCE described the project as "crucial,"[275] and "essential."[276]

In the TY 2009 GRC, DRA recommended no funding for the project, in part because SCE could not identify what equipment was the basis of its estimates or explain the potential vendors' knowledge of Phase Measurement and Grid Stability Systems. The Commission, however, found SCE's 2009 $13.0 million forecast reasonable and adopted it.[277] As it turns out, in 2009 and 2010, however, SCE spent only $2.5 million on this "crucial" project that was so "essential."

In this GRC, DRA again asked SCE to explain the unit cost basis of the proposed capital expenditures for this program and was told that the costs "…were based in part on engineering judgment and estimates."[278] Although SCE says the "scope of the project has changed since the last GRC," SCE still has not provided an engineering study to show how this system will work

---

[273] Ex. SCE-3, Vol. 2, pp. 81-82, lines 7-2, emphasis added.

[274] D.09-03-025, Section 8.3.6.1, mimeo, page 222.

[275] Ex. DRA-34, TY 2009 GRC Ex. SCE-03, Vol. 3, Pt. 5, p. 63.

[276] Ex. DRA-34, p. 63.

[277] D.09-03-025, Section 8.3.6.1., mimeo, page 222.

[278] Ex. DRA-7, p. 17.

with SCE's existing systems, or whether it is the most cost efficient for ratepayers.[279] SCE argues that it changed the scope because it anticipated the passage of standards relating to digital fault recorders. Those "standards," however, are still pending.[280]

This program is not required by statute or regulation, SCE's support for its proposed costs is thin, and SCE's repeated request to fund the same project as critical or crucial to reliability, when the Company then spends the funding on something else, calls into question the credibility and reliability of SCE's forecasts. DRA recommends that, in this GRC, the Commission discontinue ratepayer funding of SCE's Phasor Measurement & Wide-Area Situational Awareness System program.

5.2.9. Centralized Remedial Action Schemes (C-RAS)

SCE says its proposed Centralized Remedial Action Schemes project "…will centralize control and operations of SCE's …. critical protection systems that help avoid cascading outages and wide-spread system disruptions." SCE says that Remedial Action Schemes use automated programs that protect transmission equipment and ensure the stability of the transmission system in the event of transmission line outages, overload or other disturbances.[281]

In this GRC, SCE seeks $16.541 million in 2011for Centralized Remedial Action Scheme (C-RAS) capital expenditures.[282] In this GRC, SCE also says "[w]e *need* centralized control…." and that the "*need* for CRAS has become more acute since SCE's 2009 GRC."[283] According to SCE's TY 2012 testimony, "[w]ithout CRAS, SCE *will be faced with the prospect of constructing massive amounts of new transmission* with long lead times in order to safely and reliably interconnect new generation."[284]

In SCE's last GRC, SCE requested $112.2 million over the period 2007-2011 for its Centralized Remedial Action Scheme, of which $54.1 million was allocated to FERC. In its TY 2009 GRC testimony, SCE said, "[i]f we do not implement this project, SCE *would be faced with the untenable prospect of constructing of massive amounts of new transmission lines* in order to

---

[279] Ex. DRA-7, p. 16-18.

[280] Ex. SCE-18, Vol. 2, p. 66.

[281] Ex. SCE-3, Vol. 2, p. 88, lines 1-8.

[282] Ex. SCE-18, Vol. 2, p. 67, Table IV-16.

[283] Ex. SCE-18, Vol. 2, p. 68, lines 6 and 15.

[284] Ex. SCE-18, Vol. 2, p. 68, emphasis added.

avoid the tripping of generation or customer load under system contingencies."[285] This Commission authorized SCE a CPUC portion of $58.1 million of capital expenditures associated with the C-RAS program.[286]

Despite being authorized $58.1 million for capital expenditures for the Centralized Remedial Action Scheme project for the period 2007 to 2011, and despite the claim that it was being faced with the "untenable prospect of constructing massive amounts of new transmission lines," during the period 2007-2010, SCE spent less than $600,000 on the project.

In this GRC, as with SCE's other Advanced Technology proposals, DRA asked for a cost/ benefit analysis. SCE did not provide one. DRA asked if the program was required by statute or regulation; it is not.[287] When asked for the basis of SCE's cost estimates, SCE's response was that the "…labor amounts and equipment quantities noted in workpapers were developed from the SCE's project management experience and engineering judgment."

The lack of verifiable support for the costs or the benefits of this program, along with SCE's claim in the last GRC that the project was "needed," when in fact SCE did almost nothing on the project with the $58 million it was authorized, leads DRA to recommend that the Commission discontinue ratepayer funding of SCE's Centralized Remedial Action Scheme in 2011 and TY 2012.

5.2.10. Smart Grid Cyber Security

SCE says that it will begin implementing in 2012 a centralized, comprehensive smart grid cyber security solution to manage threats posed by the deployment of smart grid systems.[288] DRA asked SCE to explain the basis of the unit costs for these proposed capital expenditures. DRA was told that the"… design and specifications were based on engineering judgment," and that the quantity basis was also based on "SCE's engineering judgment."[289]

As with SCE's other Advanced Technology proposals, DRA asked for a cost / benefit analysis. SCE did not provide one. DRA asked if the program was required by statute or

---

[285] Ex. DRA-34, Excerpts from SCE's TY 2009 GRC p. 32, emphasis added.

[286] D.09-03-025, Section 8.3.6.6., pages 225-226.

[287] Ex. DRA-7, p. 19.

[288] Ex. SCE-3, Vol. 2, p. 98, lines 1-3.

[289] Ex. DRA-7, p. 21.

regulation; it is not.[290] Nor does SCE have any historical spending in this area to use as a comparison.

Given the vagueness of SCE's showing about what it would actually spend the money doing, and how whatever it would do would actually "ensure that customers will be able to realize the full benefits of a smart grid without compromising their privacy or the safe and reliable operation of the grid," DRA recommends zero ratepayer funding for this project.

5.2.11. Advanced Technology Laboratories

SCE is seeking $10.9 million in Advanced Technology Laboratory capital expenditures over the period 2010 to 2012 ($2.3 million in 2010, $2.6 million in 2011 and $6.0 million in 2012). DRA is recommending that SCE receive its requested amount of $10.9 million reallocated over this period to reflect SCE's actual capital expenditures during 2010 ($4.6 million in 2010, $3.2 million in 2011 and $3.2 million in 2012). This amount will allow SCE to accomplish what it describes as the mission of the Advanced Technology division, and level out the capitalized expenditures over the period. DRA's proposal will also allow SCE's ratepayers to benefit from the new 2010 tax law that enables the Company to deduct 100% of 2011 investments from the bonus depreciation provision of the Tax Relief Act.

In Rebuttal, SCE criticizes DRA for not "address[ing] the last two years of the five-year forecast SCE provided."[291] As discussed above, for the past two SCE GRC decisions, the Commission has explicitly declined to use SCE's "budget based" foreacasts for post-test year capital expenditures. DRA's recommendations for Post-Test Year Ratemaking are discussed in Section 16, below.

5.3. T&D – Electric System Planning

Operation and Maintenance Expenses - 561.210, 587.210

SCE forecast $6.632 million for its Electric System Planning expenses.[292] SCE developed its forecast by utilizing its 2009 recorded adjusted expenses for Sub-Accounts 561.210 and 587.210 plus incremental expenses for proposed projects and work activities. The

---

[290] Ex. DRA-7, p. 21, citing Data Response to DRA-SCE-212-MKB Question 3.m.

[291] Ex. SCE-18, Vol. 2, p. 75.

[292] Ex. SCE-3, Vol. 3, Part 1, Chapters I-II, page 5.

corresponding DRA estimate for SCE's Electric System Planning expenses is $4.656 million, which is $1.976 million less than SCE's forecast.

561.210 – Transmission Interconnection & Planning

SCE forecast $5.305 million for Sub-Account 561.210 (Labor of $4.321 million and Non-Labor of $0.990 million) for its Transmission Interconnection & Planning expenses.[293] SCE's forecast of $5.305 million is an increase of $0.910 million or 20.71% over its 2009 recorded adjusted expenses of $4.395 million. DRA utilized a five year average (2005-2009) as a basis for its forecast of $3.692 million for SCE's Sub-Account 561.210. DRA's estimate is $1.613 million less than SCE's forecast.

SCE's request for a 20.71% increase in the test year is not justified. SCE's expenses fluctuated slightly between 2005 and 2008 with an average for the four year period of $3.515 million before increasing by $0.631 million or 16.76% in 2009. SCE states that the "volume of work varies based on the additional criteria that have to be taken into consideration – such as new reliability standards or number of generators requesting interconnection to SCE's transmission grid".[294] DRA's use of a five year average (2005-2009) address the fluctuations in work activities recorded to this Sub-Account.

SCE claims that the increase was due to increases in generation interconnection requests, analysis on system changes relating to NERC Reliability Standards, a new project relating to the expansion of a freeway, and additional staffing.[295] SCE's forecast for Sub-Account 561.210 includes incremental funding for additional staffing and "increasing NERC and generator interconnection related work".[296] DRA requested additional information on SCE's work activities and its test year forecasts.

DRA asked:[297]

> Provide the documentation that explains in detail if SCE performed work activities associated with any Renewable Portfolio Standards prior to 2008 with expenses recorded to Sub-Account 561.210.

SCE's response:

---

[293] Ex. SCE-3, Vol.3, Part 1, Chapters I-II, page 7.

[294] Ex. DRA-5, p. 115 citing DRA-SCE-218-TLG question 11.

[295] Ex. SCE-3, Vol. 3 Part 1, Chapters I-II, page 7.

[296] Ex. SCE-3, Vol. 3 Part 1, Chapters I-II, page 8.

[297] Ex. DRA-5, p. 116, citing DRA-SCE-218-TLG question 7-g.

> SCE does not track the expenses recorded in 561.260 associated with Renewable Portfolio Standard discretely, but the Transmission Interconnection & Planning organization did perform work associated with this in 2008.

DRA asked:[298]

> Provide the historical costs (2005-2009) associated with NERC Reliability Standards that were recorded in Sub-Account 561.210 in order to demonstrate that costs are increasing in the test year.

SCE's response:

> SCE does not track the expenses associated with NERC Reliability standards discretely in this Sub Account. Please refer to response for Question 6b of this set for additional details regarding increasing work in this category.

DRA asked:[299]

> Provide all T&D O&M expense Sub-Accounts where SCE is requesting funding to address NERC Reliability Standards and the total amount requested in each Sub-Account.

SCE's response:

> Please refer to the response to Question 4 of DRA-Verbal-052. As described in that presentation, NERC reliability standards affect almost the entire company. Since NERC standards and requirements are reflected in new facilities, equipment, and operating systems, the costs of meeting NERC reliability standards are reflected in capital, as well as O&M costs. Because the NERC standards have been in effect for an extensive period of time, the costs of meeting current and upcoming standards is reflected in on-going operations as well the GRC forecast, and cannot be isolated from other costs. Please also refer to the response to Question 3, of DRA-Verbal-052, where SCE has provided the incremental costs of meeting NERC CIP requirements for 2012 Test Year.

DRA asked:[300]

---

[298] Ex. DRA-5, p. 116, footnote 273 citing DRA-SCE-218-TLG question 8-a. Although SCE claims that work associated with NERC Reliability Standards is expected to grow in the test year it has not tracked embedded costs associated with this activity and DRA discovered that SCE "has been performing work related to NERC Reliability Standards in this expense category since 2006" (DRA-SCE-218-TLG question 8-c). See Section 5.18 for a contintued discussion of NERC costs and the reasons why these costs should not be approved in this rate case.

[299] Ex. DRA-5, p. 117, citing DRA-SCE-218-TLG question 8-b.

> Provide the documentation that explains in detail if SCE performed any "thorough system impact evaluations" in 2008 that were associated with "generation interconnection requests driven by Renewable Portfolio Standards", if so, provide all associated costs for 2008.

SCE's response:

> SCE did perform system impact studies for generator interconnection requests, but does not have a list available for studies performed in 2008. The system impact studies associated with a particular generator requesting interconnection to the SCE grid is funded by the customer. The expenses recorded in 561.210 are for ancillary workload driven by the generation interconnection requests. They support development of cost estimates associated with Phases I and II of GIPR (Generation Interconnection Process Reform) process, assist in LGIA (large Generator Interconnection Agreement) negotiations, support regulatory proceedings (CPCN, CPUC Rate cases, FERC Rate Cases, FERC incentive filing etc), work with counties to determine fair access to SCE grid among various generators, perform land use planning, plan outage during construction, etc.
>
> SCE does not track the expenses associated with these activities discretely.

SCE's responses are insufficient and do not justify additional funding. SCE has embedded funding[301] in its historical expenses related to on-going NERC activities as well as from completed projects that can be utilized in the test year to address its projects and no additional funding is required over DRA's test year estimates of $3.692 million.

587.210 – Load Side Support Power Quality, Radio and TV Interference

SCE forecast $1.327 million for Sub-Account 587.210 (Labor of $0.919 million and Non-Labor of $0.408 million) for its Load Side Support Power Quality, Radio and TV Interference expenses.[302] SCE's forecast of $1.327 million is an increase of $0.363 million or 37.66% over its 2009 recorded adjusted expenses of $0.964 million. DRA utilized SCE's last record as a basis for its forecast of $0.964 million for SCE's Sub-Account 587.210.

---

[300] Ex. DRA-5, p. 117, citing DRA-SCE-218-TLG question 7-d.

[301] In SCE's 2009 GRC SCE was authorized $10.691 million (in 2009 constant dollars) for FERC Account 561. Of that amount, $5.785 million was authorized to address activities recorded in Sub-Account 561.210 (the remainder of the authorized amount was to address activities in Sub-Account 561.170). SCE's 2009 recorded adjusted expenses for Sub-Account 561.210 is $4.395 million, which is less than authorized, and the embedded funding can be allocated in the test year for SCE's test year activities (Ex. DRA-5, p. 118, footnote 276.).

[302] Ex. SCE-3, Vol. 3, Part 1, Chapters I-II, page 10.

SCE's request for a 37.66% increase is not justified. SCE's expenses declined each year between 2005 and 2008 from $1.239 million in 2005 to $0.865 million in 2008. SCE's expenses remained relatively stable between 2007 and 2009, with an average for the three year period (2007-2009) of $0.942 million. SCE states "as analog televisions are replaced by digital equipment, the issue of radio and television interference is significantly reduced and the demand for Radio and TV interference inspectors have gone down".[303] DRA requested additional information from SCE on its test year forecast.

DRA asked:[304]

> Provide the documentation that explains in detail if during 2005 through 2009, SCE was aware that its customers were adding devices and equipment such as plasma TV's copiers/scanners and appliances with digital programming to their homes and work locations as SCE's recorded adjusted expenses recorded in Sub-Account 587.210 were decreasing. If so, provide the documentation that explains in detail how SCE was able to address the related problems mentioned above while its expenses were decreasing each year to fully justify a labor increase in the test year of 53.94% over 2009 recorded adjusted expenses

SCE's response:

> The change from 2005 through 2009 was mostly due to replacement of analog devices with digital devices, which temporarily reduced power quality and service interference issues. SCE is aware of increase in the number of devices in customers homes and work locations. It has been able to address the volume of work with the existing inspectors, but we do not believe this sustainable in the long term. Please refer to the response to Question 16d of this set for additional information regarding the type and volume of work these inspectors are expected to perform.

DRA asked:[305]

> Provide the cost benefit analysis prepared prior to this data request that SCE's management relied upon to determine that its labor expenses needed to increase by 53.94% over 2009 recorded adjusted expenses

SCE's response:

---

[303] Ex. SCE-3, Vol. 3, Part 1, Chapters I-II, page 10.

[304] Ex. DRA-5, p. 119, citing DRA-SCE-218-TLG question 16-e.

[305] Ex. DRA-5, p. 120, citing DRA-SCE-218-TLG question 16-c.

> SCE did not perform a formal cost benefit analysis to determine the 2012 forecast for Sub Account 587.210. The forecast is based on management judgement about the number of Power Quality inspectors needed to maintain adequate service to customers.

DRA asked:[306]

> SCE states "though radio and TV interference issues have decreased, power quality issues faced by customers have increased as customers continue to add devices and equipment such as plasma TV's copiers/scanners and appliances with digital programming to their homes and work locations". Provide the documentation that demonstrates in detail all the "power quality issues faced by customers" that "have increased as customers continue to add devices and equipment such as plasma TV's copiers/scanners and appliances with digital programming to their homes and work locations" for 2005 through 2009 and the associated costs.

SCE's response:

> The need for Power Quality inspectors had decreased from 2005 to 2009, as reflected in the decrease in number of inspectors and recorded labor expenses (Figure I-4 in testimony). SCE does not record expenses discretely by the type of equipment that caused power quality or interference issues. The rational for the expected increase in work load is provided below. The demand for services of the Power Quality department is rising. The increasing use of microprocessors and the shift from electric to electric loads are causing considerable harmonic distortions. To counter these issues, the needs of individual customers need to be identified, customized solutions have to be developed, and harmonic filters have to be installed appropriately. The Power Quality inspectors provide this service…

SCE's responses are insufficient and incomplete and do not justify a 53.94% labor expense increase in the test year. SCE's recorded expenses have declined during the historical period as consumer purchases of plasma TV's, digital copiers/scanners and other digital equipment have increased. DRA's use of SCE's 2009 recorded adjusted expenses of $0.964 million for Sub-Account 587.210 as a test year estimate is reasonable and comparable to SCE's recent expense levels.

---

[306] Ex. DRA-5, p. 120, citing DRA-SCE-218-TLG question 16-d.

5.4. T&D – Load Growth

Capital Expenditures

SCE says that capital expenditures in the Load Growth area are primarily designed to accomplish two objectives: 1) strengthen the system to accommodate projected growth in demand due to the addition of new customers and/or existing customers increasing their current loads, and 2) interconnect new generating plants to SCE's system. There are 10 project categories that make up the Load Growth area.[307] Of these 10 categories, DRA is recommending adjustments to four of them. Each of these proposed adjustments is discussed in the following sections.

SCE presents its Load Growth testimony in Exhibit SCE-3, Volume 3, Part 1 and 2, Chapters I-II. SCE presents its Load Growth Rebuttal testimony in Exhibit SCE-18, Vol. 3, Part 1 & 2. (Rebuttal testimony for Plug-In-Electric Vehicles is presented in Exhibit SCE-18, Vol. 2.) All references to SCE's Direct testimony and Rebuttal testimony in the Load Growth sections that follow refer to those specific SCE exhibits.

5.4.1. Subtransmission Lines Plan

SCE presents a list of its proposed Subtransmission Lines capital projects in its Direct testimony.[308] SCE provides a discussion of each of the 27 projects in the pages that follow. Upon reviewing SCE's description of these projects, DRA noted that four of them had been previously approved by the Commission in SCE's 2009 GRC, but had been deferred to this current GRC due to delays in obtaining permits. For example, SCE describes how the Valley-Auld 115 kV Line has been delayed from prior GRCs due to problems in acquiring necessary permits.[309]

SCE acknowledges these deferrals.[310] In its direct testimony, SCE lists all of the Subtransmission Line projects (as well as the Substation projects) that were deferred from the last GRC.[311] As part of its analysis of this area, DRA sought to determine whether such delays

---

[307] Ex. DRA-6, p. 5, Table 6-1.

[308] Ex. SCE-3, Vol. 3, Part 1 & 2, Chapters I-II, p. 48, Table II-6.

[309] Ex. SCE-3, Vol. 3, Part 1 & 2, Chapters I-II, p. 49, lines 14-16.

[310] Ex. SCE-3, Vol. 3, Part 1 & 2, Chapters I-II, p. 27.

[311] Ex. SCE-3, Vol. 3, Part 1 & 2, p. 27, Table II-3.

might occur with any of the 27 Subtransmission Line projects that are being requested in this GRC.

During the capital review process of a GRC, DRA seeks to determine whether the requesting utility has adequately justified the need for each of its proposed capital projects. If so, DRA then seeks to determine that the estimated cost of each project is reasonable. For power line projects (as well as for substation projects, which will be analyzed later in this exhibit), utilities have an additional regulatory requirement that must be met. General Order (GO) 131-D states, in part, the following in Section III.B:

> *"No electric public utility shall begin construction in this state of any electric power line facilities or substations which are designed for immediate or eventual operation at any voltage between 50 kV or 200 kV or new or upgraded substations with high side voltage exceeding 50 kV without this Commission's having first authorized the construction of said facilities by issuance of a permit to construct in accordance with the provisions of Sections IX.B, X, and XI.B of this General Order."*[312]

In later portions of GO 131-D, there is a list of a number of exemptions to this Order. This Brief is not meant to be a tutorial on environmental regulation. However, it is important to note that, as part of its regulatory burden, for each Subtransmission Line project exceeding 50 kV, SCE must either obtain a Permit To Construct (PTC) or a Certificate of Public Convenience and Necessity (CPCN) from the Commission, or it must determine that the project falls under one of the exempt categories, which excludes the project from compliance with the PTC portions of the Order.

To investigate this matter further, DRA issued a data request to SCE.[313] The thrust of this data request is to obtain, for each of the 27 Subtransmission Line projects, an explanation of what authority SCE was operating under in order to proceed with these capital projects. DRA expected to receive a list showing that each project had either: 1) received some type of authority from the Commission allowing the project to go forth, or 2) fallen under one of the exemptions listed in GO 131-D. In responding to this data request, SCE notes in its reply to Question 1.c, that many of these projects are exempt from GO 131-D requirements.[314] As part of its data

---

[312] Emphasis added.

[313] Ex. DRA-6, Appendix A, DRA-223-GAW.

[314] Id.

request response, SCE also included a spreadsheet that provided the detailed project-by-project authorization information that DRA had requested.[315] For many of the projects, the last column of the spreadsheet (the "Comments" column) identifies the specific exemption category that SCE claims the project falls under.

SCE claims that many of the proposed Subtransmission Line projects are exempt from the permitting process. DRA is not at this time challenging any of the exemptions being proposed by SCE. However, DRA also noted that for five of the 27 projects, SCE has neither provided any authorization that allows it to proceed with the project, nor provided any claim of exemption. This appears to be a direct violation of the GO 131-D language quoted previously. SCE should not be allowed to proceed with any power line project without having complied with the requirements of this General Order.

DRA is questioning each of the five projects for which SCE has failed to provide authorization details. Absent any approval to proceed from the Commission, and absent any claim that these projects fall under one of the exemption categories contained in GO 131-D, DRA can ascertain no reason why funding for these five should be allowed. Consequently, DRA is recommending no ratepayer funding for all capital expenditures associated with these projects. The net result of DRA's recommendations is a reduction of $2.070 million in 2011 Subtransmission Lines capital expenditures, with an additional $3.829 million reduction in 2012.[316]

In its Rebuttal testimony, SCE provided new data regarding the five projects which it previously had failed to provide. DRA strongly believes that this new information should be stricken.[317] There is ample Commission precedent stating that new data should not be provided during the Rebuttal phase of the case. As the Applicants, SCE has control of all the data in this case. Allowing SCE to withhold information during the Discovery phase of the GRC, and then selectively provide it during the Rebuttal phase, puts DRA in an untenable position. If this practice is allowed to occur, SCE would have no incentive to respond to DRA's data requests, preventing DRA (as well as other intervenors) from conducting the types of analyses necessary to assess the reasonableness of SCE's forecasts.

---

[315] Id.

[316] Ex. DRA-6, p. 14.

[317] This new information is the subject of a DRA Motion to Strike, which is pending as of this writing.

In the event that DRA's Motion to Strike is not granted, DRA believes that it is necessary to correct the allegations that SCE has made in its Rebuttal testimony. SCE's first allegation is that lines in Data Request DRA-223-GAW were left blank because the projects were not far enough along in the planning process to be evaluated for compliance, and that it is not unusual for projects with on-line dates within the next few years to have not yet been evaluated.

DRA disagrees with SCE's Rebuttal allegations. Of the 35 Subtransmission Line projects proposed by SCE, 17 of them have completion dates in 2012 through 2014. SCE was able to provide the requested compliance status for 13 of the 17. SCE has not explained why it could provide details for those 13 projects and not the remaining 4. In its testimony and workpapers, SCE has provided DRA with comprehensive forecasts for each project. By the time a comprehensive forecast has been developed, DRA believes that SCE should be able to ascertain whether or not Commission authorization for the project is necessary; by this stage, SCE should also know whether or not an exemption is possible. Without Commission authorization or an exemption, SCE is not in compliance with GO 131-D, and should not be allowed to undertake these projects. In addition, nothing in SCE's Rebuttal explains the failure of SCE to provide compliance details for the Brookhurst project, which has a completion date of 6/1/2011.[318] That project was not "years" away from completion, but only a couple of months away. There is no legitimate reason for SCE to fail to provide the compliance status.

SCE's next allegation in its Rebuttal is that some of the lines in SCE's response to Data Request DRA-223-GAW were left blank because the project was a substation modification that is not subject to GO 131-D.

This allegation strikes DRA as being illogical, and does not respond to DRA's concerns. As shown in DRA's testimony,[319] SCE noted (in the last column of the table) that several projects were considered to be modifications. However, in its Rebuttal testimony, SCE now seems to be saying that for other capital projects, it deliberately omitted providing the requested information because it knew that they were considered modifications. This is nonsensical – SCE seems to be saying that important details regarding the status of some projects is provided, but for others it is deliberately withheld. In its testimony and workpapers, SCE has provided DRA with comprehensive forecasts for each project. By the time a comprehensive forecast has been

[318] Ex. DRA-6, p. 56, line 12.

[319] Id., lines 5 and 10.

developed, DRA believes that SCE should be able to ascertain whether or not Commission authorization for the project is necessary; if an exemption is possible, that is something that SCE should also know. Logic would seem to dictate that SCE's comprehensive plans would include such items as purchasing additional land, expanding fence boundaries, etc, all of which are items that would indicate whether or not the project was simply a modification or actually an upgrade or expansion. Without Commission authorization or an exemption, SCE is not in compliance with GO 131-D, and should not be allowed to undertake these projects.

SCE's last allegation is that DRA is drawing the wrong conclusion that these projects cannot be constructed on-time simply because SCE has not made a determination regarding exemptions.

In response to this, DRA would like to point out that requests for exemptions can be challenged and protested, which would obviously have the potential to delay a project. In this situation, without authorization or an exemption, the Commission cannot know what sort of protests may be forthcoming. However, DRA's concern goes beyond possible scheduling issues. The relevant section of GO 131-D states that no utility can begin construction without authorization or an exemption. SCE has not supplied DRA with proof of either, yet for many projects, it is forecasting expenditures in 2010 and/or 2011. This appears to contradict the language and be a violation of GO 131-D.

5.4.2. Distribution Substation Plan (DSP)

SCE presents a list of its proposed Distribution Substation capital projects in its Direct testimony.[320] SCE provides a discussion for each of the 75 projects in the pages that follow. Upon reviewing SCE's description of these projects, DRA noted that several of them had been previously approved by the Commission in SCE's 2009 GRC, but had been deferred to this current GRC due to delays in obtaining permits. For example, SCE describes how the Kimball 66/12 kV Substation project has been delayed from prior GRCs due to problems in acquiring necessary permits.

SCE acknowledges these deferrals. In its Direct Testimony, SCE lists all of the Substation projects (as well as the Subtransmission Line projects) that were deferred from the

[320] Ex. SCE-3, Vol. 3, Part 1 and 2, Chapters I-II, p. 70, Table II-8.

last GRC. As part of its analysis of this area, DRA sought to determine whether such delays might occur with any of the 75 DSP projects that are being requested in this GRC.

As discussed above, during the capital review process of a GRC, DRA seeks to determine whether the requesting utility has adequately justified the need for each of its proposed capital projects. If so, DRA then seeks to determine that the estimated cost of each project is reasonable. For substation projects, utilities have an additional regulatory requirement that must be met. General Order (GO) 131-D states, in part, the following in Section III.B:

> *"No electric public utility shall begin construction in this state of any electric power line facilities or substations which are designed for immediate or eventual operation at any voltage between 50 kV or 200 kV or new or upgraded substations with high side voltage exceeding 50 kV without this Commission's having first authorized the construction of said facilities by issuance of a permit to construct in accordance with the provisions of Sections IX.B, X, and XI.B of this General Order."*[321]

In later portions of GO 131-D, there is a list of a number of exemptions to this Order. Again, this brief is not meant to be a tutorial on environmental regulation. However, it is important to note that as part of its regulatory burden, for each Distribution Substation project with a high side voltage exceeding 50 kV, SCE must either obtain a Permit To Construct (PTC) or a Certificate of Public Convenience and Necessity (CPCN) from the Commission, or it must determine that the project falls under one of the exempt categories, which excludes the project from compliance with the PTC portions of the Order.

To investigate this matter further, DRA issued a data request to SCE[322] to obtain, for each of the 75 DSP projects, an explanation of what authority SCE was operating under in order to proceed with these capital projects. DRA expected to receive a list showing that each project had either: 1) received some type of authority from the Commission allowing the project to go forth, or 2) fallen under one of the exemptions listed in GO 131-D. In responding to this DR, SCE notes in its reply to Question 2.c, that many of these projects are exempt from GO 131-D requirements.[323] As part of its data response, SCE also included a spreadsheet that provided the

---

[321] Emphasis added.

[322] Ex. DRA-6, Appendix B, DRA-223-GAW

[323] Id.

detailed project-by-project authorization information that DRA had requested.[324] For many of the projects, the last column of the spreadsheet (the "Comments" column) identifies the specific exemption category that SCE claims the project falls under.

SCE claims that many of the proposed DSP projects are exempt from the permitting process. DRA is not challenging any of the exemptions being proposed by SCE at this time. However, DRA also noted that for 35 of the 75 projects, SCE has neither provided any authorization that allows it to proceed with the project, nor provided any claim of exemption. This appears to be a direct violation of the GO 131-D language quoted previously. SCE should not be allowed to proceed with any substation project without having complied with the requirements of this General Order.

DRA is questioning each of the 35 projects for which SCE has failed to provide authorization details. For at least one of these 35 projects (the Thornhill 115/12 kV line), SCE has now determined that the project is no longer necessary and has cancelled it. Absent any approval to proceed from the Commission, and absent any claim that these projects fall under one of the exemption categories contained in GO 131-D, DRA can ascertain no reason why funding for these 35 should be allowed. Consequently, DRA is recommending no ratepayer funding for all capital expenditures associated with these projects. The net result of DRA's recommendations is a reduction of $25.155 million in 2011 DSP capital expenditures, with an additional $55.853 million reduction in 2012.[325]

While DRA's total recommended adjustments is quite large, it is actually less than the total costs of the deferred distribution substation projects that are listed in SCE's testimony.[326] DRA's proposed reductions are quite modest when compared to the total cost of these previously authorized substations that were deferred. It is clear that Distribution Substation projects are subject to delays. As set forth in DRA's testimony, it can be seen that a dozen dates have been highlighted in the "Current Proposed Op Date" column.[327] Each of those dates represents a revision to SCE's original completion estimates. It is clear that project delays are continuing.

---

[324] Id.

[325] Ex. DRA-6, p. 16.

[326] Ex. SCE-3, Vol. 3, Part 1 & 2, Chapters I-II, p. 27, Table II-3. The total cost of the nine deferred substation projects listed in Table II-3 is $116.659 million. Note that this is a "total" cost, meaning that it is the sum of all the capital expenditures that occurred over the total multi-year construction period.

[327] Ex. DRA-6, p. 61.

In its Rebuttal testimony, SCE provided new data regarding the 35 projects which it previously had failed to provide. This new data is also the subject of a Motion to Strike. DRA strongly believes that this new information should be stricken. There is ample Commission precedent stating that new data should not be provided during the Rebuttal phase of the case. As the Applicant, SCE has control of all the data in this case. Allowing SCE to withhold information during the Discovery phase of the GRC, and then selectively provide it during the Rebuttal phase, puts DRA in an untenable position. If this practice is allowed to occur, SCE would have no incentive to respond to DRA's data requests, preventing DRA (as well as other intervenors) from conducting the types of analyses necessary to assess the reasonableness of SCE's forecasts.

In the event that DRA's Motion to Strike is not granted, DRA refers the Commission to DRA's responses to SCE's allegations set forth in the previous section of this Brief as also applicable here.

5.4.3. Substation Equipment Replacement Program (SERP)

The Substation Equipment Replacement Program (SERP) evaluates the adequacy of substation terminal equipment and system protection devices. SCE discusses SERP in its Testimony.[328] Based on this discussion, SCE states that it needs to replace various quantities of several different types of circuit breakers.

In its testimony, SCE includes Table II-9, which provides additional details regarding the types of circuit breakers that are being replaced, their unit costs, and the total capital expenditures SCE is proposing per year.[329] The first thing to note regarding SCE's SERP is how total expenditures abruptly increase starting in 2010. Prior to that year, the highest recorded expenditure was $1.441 million in 2008. For 2012, SCE is forecasting $9.000 million, over six times higher than the previous largest expenditure. By any definition of the word, this is a "significant" proposed increase.

Also worth noting is how the number of proposed 66 kV circuit breaker replacements is increasing.[330] SCE states that it has identified 211 circuit breakers that need replacing, which it

---

[328] Ex. SCE-3, Vol. 3, Parts 1 & 2, Chapters I-II, p. 115.

[329] In order to more easily analyze this information, DRA rearranged the data and included recorded information going back to 2005. DRA's results are set forth in Ex. DRA-6, Table 6-2,

[330] Ex. DRA-6, Table 6-2.

intends to do over the period 2010 through 2014. DRA agrees that the circuit breakers will need replacing, but believes that doing so over a slightly longer period of time is more reasonable.[331]

DRA does not take issue with SCE's proposed replacement schedule for the 12/16 kV circuit breakers. However, DRA is proposing adjustments to the 66 kV replacements. SCE proposes to replace 26 of the 66 kV circuit breakers in 2011, and replace 36 per year thereafter through 2014. The total number of replacements for those four years equals 134.[332] DRA's recommendation is to replace 26 circuit breakers each year, which means that replacing 134 breakers will take a little over five years.[333]

SCE is not required or mandated to complete these replacements in four years, nor has SCE demonstrated an operational need to complete these replacements in its proposed time frame. In 2010, SCE proposes replacing 27 breakers, and in 2011, 26 more. If SCE considered these replacements to be a matter of some urgency, at the very least it would have proposed replacing 36 breakers per year beginning in 2010 (not 2012). In DRA's judgment, replacing 26 of the 66 kV circuit breakers per year is reasonable; not only is the work load evenly distributed over all the years, but an abrupt expenditure jump is avoided in 2012. DRA's recommendation results in a $2.000 million decrease in 2012 SERP capital expenditures.[334]

In its Rebuttal testimony, SCE presents four criticisms of DRA's testimony.[335] SCE first alleges that DRA's proposal to reduce SCE's proposed number of 66 kV circuit breaker replacements (from 36 to 26) is arbitrary. Obviously, DRA disagrees with this statement. DRA's recommendation is consistent, continuing the pattern of replacements established by SCE in 2010 and 2011. If anyone's estimates are arbitrary, it is SCE's; it is SCE who is proposing the sudden increase in replacements in the test year.

SCE's second allegation is that DRA fails to recognize the serious operational and safety-related implications of delaying circuit breaker replacements. In response, DRA would like to note for the record that it is well aware of the safety and reliability issues associated with circuit

---

[331] Ex. DRA-6, p. 17.

[332] Ex. DRA-6, p. 19. 26 circuit breakers (for 2011) + 36 circuit breakers times 3 (for the years 2012, 2013, and 2014) = 134.

[333] Ex. DRA-6, p. 19. 134 circuit breakers ÷ by 26 replacements per year = 5.15 years to replace them all.

[334] Ex. DRA-6, p. 19.

[335] Ex. SCE-18, Vol. 3, Part 1 & 2, pp. 16-17.

breakers. SCE's Rebuttal testimony states that there is an immediate need to replace these circuit breakers. However, SCE's own actions belie that contention. SCE does not begin to increase the replacement rate of these breakers until 2012. There seems to be two possibilities: either SCE is endangering its workers and the public by failing to increase replacement levels in 2010 and 2011, or replacing 26 circuit breakers in 2011 adequately addresses those safety concerns. DRA cannot imagine any circumstance under which SCE would put either its own workers or the general public in harm's way. Therefore, the only conclusion that can be drawn from this is that replacing 26 circuit breakers is adequate. DRA is simply continuing the replacement pattern that SCE has established.

SCE goes on to mention that there are more than 200 circuit breakers where short-circuit duty levels exceed the interrupting level of the breakers. For safety and reliability reasons, there is an immediate need to replace those breakers. However, SCE's actions do not suggest the urgency that SCE alleges exists. SCE states that it has to "address an immediate need" to replace these circuit breakers. DRA does not understand SCE's definition of "immediate." Why is SCE waiting until 2012 to begin increasing the number of the 66 kV circuit breaker replacements? In fact, in 2011, SCE's forecast for 66 kV breakers (26 estimated) is actually lower than its 2010 forecast (27 estimated). Similarly, SCE's 2011 forecast for 12/16 kV circuit breakers (9 estimated) is less than its 2010 forecast (18 estimated). SCE's forecasts do not comport with its claims of urgency. DRA is proposing no adjustments at all to SCE's 2011 forecast for either the 66 kV or the 12/16 kV circuit breakers. For 2012, DRA is again agreeing with SCE's forecast for the 12/16 kV breakers, but is recommending that the number of 66 kV replacements be kept at the 2011 level. DRA's recommendations are neither draconian nor unreasonable.

SCE's last allegation is that DRA's proposal to lengthen the replacement schedule seems designed to arbitrarily reduce rates. DRA acknowledges that its recommendation does reduce rates, but there is nothing "arbitrary" about it. DRA carefully reviewed SCE's testimony on this subject. However, DRA's analyses, as well as SCE's own pattern of historical replacements, strongly suggest that SCE's forecasts are higher than necessary. DRA did not arbitrarily pick a number out of a hat to develop its replacement recommendations; DRA continues to use the replacement numbers developed by SCE, numbers that SCE was comfortable using for 2011.

5.4.4. Plug-In Electric Vehicle Readiness Program

SCE discusses the impact that increasing numbers of plug-in electric vehicles (PEVs) will likely have on its electrical system in its Direct Testimony.[336] SCE states that these PEVs represent a significant load on its system – as much as two or three times that of a typical household load. However, the exact impact these vehicles will have on SCE's system is a matter of much speculation. As SCE acknowledges, many important factors remain unknown – the total number of PEVs that will be purchased, the battery size of the vehicles, the potential for geographic clustering of these vehicles, and the charging behavior of the vehicles' owners are all subject to widely differing estimates.

Because of these uncertainties, SCE developed three sets of infrastructure improvement estimates (low, medium, and high forecasts) depending on the degree of market penetration of PEVs in its service territory. In its request for this GRC, SCE uses the "medium" estimate. DRA has concluded that infrastructure improvement forecasts associated with the "low" market penetration are more reasonable, given the current uncertainty associated with the PEV market.

DRA is concerned that the initial purchase price of PEVs will keep demand for these cars low. DRA acknowledges that fuel costs have gone up, which would tend to increase the popularity of PEVs. However, there are a variety of high mileage non-PEV cars that are much less expensive than plug-ins. In DRA's judgment, the economic conditions in California are likely to curtail the purchase of the more expensive PEVs.

DRA's recommended use of the "low" estimate has been bolstered by the ongoing tragedies impacting Japan. Numerous articles have discussed how the Japanese car market is going to be negatively impacted by the earthquake/tsunami and the resultant power problems. For example, AutoGuide has reported that the crisis in Japan is continuing to impact automakers and the entire auto industry, even American companies.[337] The Japanese plant that builds the high-tech transmission for the Chevy Volt has been shut down in the wake of the earthquake and resulting nuclear problems. It is becoming increasingly obvious that there simply will be fewer PEVs available for sale than had originally been assumed. Combining these supply problems with the continuing economic issues, DRA believes that it is reasonable to use the "low" estimate of PEV market penetration to estimate infrastructure improvement estimates.

---

[336] Ex. SCE-3, Vol. 3, Parts 1 & 2, Chapters I-II, p. 127.

[337] Ex. DRA-6, p. 20, footnote 9 citing March 18, 2011 article in AutoGuide.com by Blake Z. Rong.

As stated previously, SCE's forecasts were predicated on the "medium" assumption for PEV market penetration. In a verbal data request, DRA requested that SCE provide the infrastructure improvement estimates that it had developed based on the "low" assumption. As expected, SCE's response to this data request[338] shows that the "low" estimates are considerably smaller than the "medium" estimate it used in this GRC. SCE's "low" market penetration estimates of $0.134 million for 2011 and $0.782 million for 2012 are used by DRA and are shown in Exhibit DRA-6, p. 5, Table 6-1, line 9. The use of these revised estimates results in a reduction of the capital expenditures for the PEV Readiness Plan of $1.955 million in 2011 and $7.741 million in 2012.

In its Rebuttal testimony, SCE alleges that DRA appears to be inconsistent in regards to the numbers of PEVs that will be included in SCE's service territory.[339] According to SCE, in Exhibit DRA-5, DRA appears to be saying there will be no PEVs, while in Exhibit DRA-6, the assumption seems to be 33,000.[340]

DRA disputes this allegation; there are no inconsistencies. The subject matter of Exhibit DRA-5 has to do with expenses, while Exhibit DRA-6 has to do with capital. If existing expenses are sufficient to cover the impact of anticipated PEV purchases, it is reasonable for DRA to assume, for ratemaking purposes, that no additional PEVs will be purchased. At the same time, if DRA believes that SCE's distribution infrastructure should be bolstered to cover anticipated PEV purchases, it is also reasonable, for ratemaking purposes, to assume that some additional PEVs will be acquired. This is an apples and oranges comparison – the two issues cannot necessarily be equated. It is perfectly reasonable to assume that expenses do not need to increase, while at the same time, assume that capital increases are warranted.

SCE next alleges that the demand for PEVs is very high. SCE states that 34% of consumers do not have significant concerns regarding the purchase of a PEV, and that SCE's use of the "medium" scenario for PEV market penetration appears to be more reasonable than DRA's use of the "low" scenario.

---

[338] Ex. DRA-6, p. 21, footnote 10 citing SCE response to DRA Verbal Data Request #58, Q/A1, Attachment 1 of 2.

[339] Ex. SCE-18, Vol. 2, p. 9, footnote 36.

[340] Id.

DRA takes exception to the conclusions that SCE draws from these demand citations. Assuming (for the moment) that these demand figures are accurate, that does not say anything about the number of PEVs that will be purchased. Demand could be 100%, yet if the cars are not available, none will be sold. One of DRA's major concerns was that parts, as well as the vehicles themselves, would be in short supply because of the earthquake and resulting power problems in Japan. This has proven to be true. Bloomberg News reports (June 13, 2011) that Nissan is now predicting that it will deliver half the number of Nissan Leafs that it originally planned. It is also likely that customers will think twice about PEV purchases when they learn of the high price tag. The Chevy Volt is more than $40,000, while the Tesla is north of $100,000. Consumers may not have significant concerns regarding the purchase of a PEV, but that does not mean that they can afford them, even if they were available.

SCE's last allegation concerns Figure II-1 on page 10 of its Rebuttal.[341] That table provides a number of forecasts, provided by a number of sources, for PEV sales. SCE alleges this table shows how out-of-step DRA's forecasts are; DRA's estimates are clearly too low.

SCE provides few details regarding the estimates contained in the table. Of particular importance is when the estimates were derived. Do any of the estimates take into account the Japanese earthquake and its aftermath? Clearly, the estimates for SCE do not, since they were included in its November 2010 application, long before the March 2011 earthquake. The estimate attributable to the White House is not likely to reflect the earthquake, since it cites the 2010 through 2014 period, obviously prior to the March 2011 disaster. The DOE (Department of Energy) has a February 2011 publication date, so it does not reflect the impact of the ongoing crisis. The UCLA study has a May 2011 publication. DRA suspects that it does NOT reflect the impact of the earthquake, as it shows 2011 Nissan Leaf sales estimates for 2011 of 25,000 vehicles, the pre-disaster estimate for deliveries. (The post-disaster estimate is now 10,000.) Therefore, even though DRA's estimate of 33,000 PEV vehicles is lower than the other estimates, it is the only one that factored in the impact of the delivery constraints imposed by the Japanese earthquake.

[341] Ex. SCE-18, Vol. 3, p. 10.

5.5. T&D – Infrastructure Replacement Capital Expenditures

As equipment ages, the risk of experiencing failures generally increases. The capital projects SCE included under the Infrastructure Replacement area are intended seek to replace pieces of equipment prior to their failure based on a risk/reliability evaluation. Stated another way, these programs preemptively replace pieces of equipment that are still operational, based on various studies that show they may soon fail. As DRA's Direct Testimony shows, there are 14 project categories that make up the Infrastructure Replacement area.[342] Of these 14 categories, DRA is recommending adjustments to six of them. Each of these proposed adjustments is discussed in the following sections. SCE presents its Infrastructure Replacement testimony in Exhibit SCE-3, Volume 3, Part 3, Chapters I-II. References to SCE's Rebuttal testimony refer to SCE-18, Vol. 3, Part 3 and 5. All references to SCE's Direct and Rebuttal Testimony in the Infrastructure Replacement sections that follow refer to those specific SCE exhibits.

5.5.1. Cable Replacement Program

SCE discusses its Cable Replacement Program in Direct Testimony and describes the purpose of these capital expenditures as being for the proactive replacement (i.e., replacing before they fail) of underground cables.[343] SCE states that this program attempts to identify the poorest performing electrical circuits and preemptively implements improvements to those circuits where they are needed most. SCE has devoted a significant amount of time and resources analyzing Cable Replacement projects, going so far as to retain an outside consultant, Quanta Technology (Quanta) to study how aging underground cables are likely to impact the future reliability of SCE's electrical system. In its workpapers, SCE has included a copy of the report prepared by Quanta. This report, *"Impact of Aging Infrastructure on System Reliability"* examines how system reliability in 2030 will be impacted under various equipment replacement scenarios.

The proactive replacement of underground cables primarily takes place in three Infrastructure Replacement capital project categories. The first of these projects is the Cable Replacement Program, which is the subject of this analysis.[344] Two additional projects, the

---

[342] Ex. DRA-6, p. 5, Table 6-1.

[343] Ex. SCE-3, Vol. 3, Part 3, Chapters I-II, p. 15.

[344] Ex. DRA-6, p. 5, Table 6-1; Ex. DRA-6, p. 22.

Worst Circuit Rehabilitation (WCR) and the Underground Oil Switch Replacement, also contribute to the replacement of underground cable.[345]

The Cable Replacement Program is complex due to the nature of its linkage to, and interaction with, other Infrastructure Replacement programs. The Quanta report, which utilizes the results from the Cable Replacement Program as well as another program (the Worst Circuit Rehabilitation Program), adds another layer of complexity to the analysis. Because of the way these different Infrastructure Replacement programs are linked to each other and to the Quanta report, DRA concludes that a straight-forward and logical approach to analyze this capital category is to first determine a reasonable quantity (in circuit miles) of underground cable to be replaced each year. Once that total is derived, one can then determine how that quantity of replacements should be allocated among the various capital projects and to calculate reasonable expenditure levels.

In its testimony, DRA presents a very detailed analysis of the Cable Replacement Program.[346] Most of that investigation need not be reprinted here. Suffice it to say that DRA presented a logical and thorough analysis that showed that its recommendations were quite generous and would have a negligible impact on reliability. The Cable Replacement Program is sufficiently complicated that it is easy to "muddy the water" and lose sight of the important issues surrounding this capital area.

DRA agrees with SCE's 2011 forecast, but is recommending 350 circuit miles be replaced in 2012. When reading through SCE's Rebuttal testimony, it is easy to lose track of how generous DRA is being. DRA's 2012 estimate of 350 miles is far higher than any other previous year; it is even far higher than SCE's own 2011 estimate. Prior to 2009, SCE had never even replaced 100 circuit miles in any year. Not only is DRA's recommendation reasonable (even generous) when compared to historical levels of replacement, it is also reasonable from the standpoint of maintaining system reliability, the main issue discussed in the Quanta report. This issue of system reliability will be discussed in greater detail in the following paragraphs.

Having derived its estimates for this capital program, the last portion of DRA's analysis examines how these recommendations impact the reliability of SCE's system, as detailed in the Quanta report. As stated previously, Quanta investigated what impact an aging underground

---

[345] Id.

[346] Ex. DRA-6, pp. 23-26.

cable population would have on SCE's overall reliability. Quanta investigated four scenarios: 1) making no proactive replacements of underground cables, 2) annually proactively replacing 150 circuit miles, 3) annually proactively replacing 415 circuit miles, and 4) annually proactively replacing 700 circuit miles. For each scenario, Quanta attempts to measure the reliability impact on SCE's electrical system in 2030 by calculating to what degree SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) levels would change.

It is important to note that when Quanta performed its analyses of these four scenarios, underground cable replacements associated with the Oil Switch Replacement program were not factored in.[347] SCE's testimony confirms this. SCE states that it does not believe that replacements associated with the Oil Switch program have as significant an impact on reliability as the other types of underground cable replacements. The omission of the underground cable replacements associated with the Oil Switch Replacement program seems puzzling, and such an omission casts a shadow on the credibility of the analyses performed by Quanta.

As indicated in DRA's testimony setting forth SCE's recorded and forecast data, a significant amount of underground cable is associated with the Oil Switch Replacement program.[348] It is erroneous to assume that omitting such volumes of replacements will have no impact on SAIDI and SAIFI. In effect, SCE (and Quanta) are ignoring Oil Switch (Circuit Miles) when the reliability of the system is being analyzed.[349] While DRA disagrees with this omission, it does show how the 415-mile replacement figure was derived, and why it was used as one of the scenarios; by excluding the Oil Switch (Circuit Miles) data, the resulting replacement total for 2012 (and beyond) for SCE equals 415 circuit miles.[350]

SCE has included some excerpts from the Quanta report in its testimony. SCE presents four graphs that show how SAIDI and SAIFI would change with no annual replacements, with 415 circuit miles of annual replacements, and with 700 circuit miles of annual replacements. SCE did not include a graph showing the impact of annually replacing 150 circuit miles, one of

---

[347] Ex. SCE-3, Vol. 3, Part 3, Chapters I-II, p. 22, footnote 12.

[348] Ex. DRA-6, p. 24, Table 6-3, columns c and d.

[349] Ex.DRA-6, p. 24, Table 6-3, columns c and d.

[350] Ex. DRA-6, p. 24, Table 6-3: 300 circuit miles (from column a) plus 115 circuit miles (from column g) equals 415 circuit miles, the amount found reasonable by SCE.

the scenarios analyzed by Quanta. The important thing to note regarding these four graphs is that reliability is forecasted to decrease; SAIDI and SAIFI are projected to steadily increase through the year 2030. Whether 700 circuit miles are replaced each year, whether no circuit miles are replaced each year, or whether any amount between those two extremes is replaced, the result is the same – SAIDI and SAIFI are going up. The question therefore boils down to what level of increase is acceptable.[351]

In the Quanta report, SAIDI and SAIFI levels for 2030 can be found for each of the replacement scenarios.[352] As previously stated, SCE has concluded that replacing 415 circuit miles per year of underground cable (which excludes the replacement amounts associated with the Oil Switch Replacement program) is reasonable. A comparable calculation using DRA's estimates is 276 circuit miles.[353]

Quanta estimates that by 2030, SAIFI will be 0.47 higher than it is currently if 415 circuit miles are proactively replaced each year, meaning that the reliability of SCE's electrical system will be lower than it is today. Using DRA's estimate of 276 circuit miles, the comparable SAIFI increase by 2030 would be somewhat less than 0.61.[354]

What do these figures mean, and what is their significance? Using the figures in the above tabulation, increasing the annual level of proactive underground cable replacements from 150 circuit miles to 415 circuit miles will cause SAIFI to experience a decrease of 0.14 outages per year, on average, by the year 2030.[355] Stated another way, increasing the yearly proactive replacements from 150 circuit miles to 415 circuit miles will result in the average customer experiencing only <u>one</u> less outage every 7.14 years by 2030.[356]

---

[351] Ex. SCE-3, Vol. 3, Part 3, ChaptersI-II, pp. 23, 24.

[352] Ex. DRA-6, p. 29, lines 16-17: "Increases in SAIFI by 2030 (Events): O miles: 0.70; 150 miles: 0.61; 415 miles: 0.47.

[353] Ex. DRA-6, p. 24, Table 6-3: 161 circuit miles (from column b) plus 115 circuit miles (from column h) equals 276 circuit miles (which excludes the replacement amounts associated with the Oil Switch Replacement program).

[354] Ex. DRA-6, p. 30, footnote 14: The larger the annual proactive replacement, the lower the increase that SAIDI will experience by 2030. Since DRA's replacement estimate of 276 circuit miles is larger than the 150 circuit mile amount shown in the tabulation, the resulting SAIFI increase will be somewhat smaller than the 0.61 increase shown for 150 circuit miles.

[355] 0.61 events less 0.47 events equals a decrease of 0.14 events.

[356] Using a simple example to illustrate this concept, suppose that SAIFI is reduced from 1.00 to 0.90. Before the reduction, on average, a customer could expect to experience 1 outage per year. After the reliability improvement, on average, a customer could expect to experience 0.90 outages per year. Over a

The small improvement in reliability obtained by increasing the amount of yearly proactive underground cable replacements from 150 circuit miles to 415 circuit miles does not warrant the additional costs. The average SCE customer would not even be aware of any degradation in reliability if they experienced one additional outage every 7+ years. These calculations are all based on the change from 150 circuit miles to 415 circuit miles. Since DRA's actual recommendation (omitting the Oil Switch Replacement amounts) is for replacing 276 circuit miles (not 150), the real reliability improvement in SAIFI in going to 415 circuit miles is even smaller than the 0.14 increase calculated earlier.

The reasonableness of DRA's 2012 forecast can be evaluated in several ways. If the reasonableness of DRA's forecast is judged by how many total circuit miles of underground cable are to be replaced, DRA's estimate will be found to be prudent, even generous, considering that DRA is recommending a total replacement level that is 30% higher than any previous recorded year. On the other hand, if the reasonableness of DRA's forecast is based on how SCE's system reliability is impacted, DRA's estimate will again be found to be prudent – one additional outage over a period of more than 7+ years will likely not be noticed by the average customer. It is also important to consider that the time horizon being analyzed is almost 20 years in the future; numerous GRCs will occur between now and 2030, during which appropriate program modifications can be evaluated if warranted. Therefore, no matter which criterion is used as a measure, DRA's forecast of $46.820 million in 2012 capital expenditures for the Cable Replacement Program is reasonable. This recommendation results in a $27.694 million reduction to SCE's 2012 forecast.[357]

During SCE's cross examination of DRA's witness, much was made of how DRA's recommendations would impact the system reliability experienced by SCE's customers. Similarly, in SCE's Rebuttal testimony, reliability issues were raised; SCE states that while a SAIFI increase of 0.14 sounds small, it translates into an additional 686,000 customers experiencing an outage each year.

10-year period, the average customer would experience 1 fewer outage (10 outages over that period before the improvement versus 9 outages over that period after the improvement). The general formula for calculating the length of time it would take for the average customer to experience 1 fewer outage is (1 ÷ SAIFI Reduction). In this particular case, with a SAIFI reduction of 0.14, it would take on average 7.14 years for the typical customer to experience 1 less outage. (Ex. DRA-6, p. 30, footnote 16.)

[357] Ex. DRA-6, p. 5, Table 6-1.

As pointed out while on the stand, DRA's recommendation would result in something less than a 0.14 increase, so the resulting impact on ratepayers would be much less than 686,000. However, the bottom line is that a balance must be struck between capital expenditures and reliability. Even using SCE's own forecasts for cable replacements, SCE acknowledges that reliability will suffer;[358] even if SCE' s recommendation of replacing 415 miles of underground cable per year was adopted in its entirety, SAIFI would still increase by 0.47 events per year by 2030. This translates into 2,303,000 customers experiencing an additional outage each year. (4,900,000 customers x 0.47 interruptions/customer = 2,303,000 interruptions.) Clearly, SCE is using its judgment to strike a balance between expenditures and reliability. Using its judgment, DRA has concluded that it is to the ratepayers' advantage to increase the 2,303,000 outages by an additional amount (by the year 2030) in order to save many hundreds of millions of dollars between now and 2030. DRA's recommendation would cause the average customer to experience less than one additional outage every 7+ years by the time 2030 arrives.[359]

While on the stand, DRA's witness was asked by the ALJ whether a precise calculation had been made regarding the impact his recommendations would have on SAIFI. DRA's witness stated that he had avoided trying to quantify what the exact impact would be, because an absolutely accurate estimate would require that the Quanta consultants conduct a detailed modeling run. However, using a simple linear interpolation, a rough estimate is possible. DRA's testimony[360] shows a table containing various estimates for cable replacements and the associated increases to SAIFI. Since DRA's recommendation to replace 276 circuit miles of cable is roughly mid-way between the 150 mile scenario and the 415 mile scenario, the change in SAIFI would also be mid-way. Therefore, using this rough approximation, DRA's recommendation would cause the 2030 SAIFI level to increase by 0.07 (not 0.14) over SCE's recommendation of 0.47. An increase of 0.07 would increase the number of yearly outages by 343,000[361] (on top of SCE's 2.3 million increase).

During his time on the stand, DRA's witness was also asked about SAIDI and SAIFI definitions contained in Decision 96-09-045. DRA's witness agreed that the definitions

---

[358] See Ex. DRA-6, p. 29.

[359] Ex. DRA-6, p. 31.

[360] Ex. DRA-6, p. 29.

[361] 4,900,000 customers x 0.07 outages/customer = 343,000 outages.

presented in the decision were correct. However, it should be pointed out that D.96-09-045 is 15 years old. Much of the discussion in the decision appears to be concerned with how Performance Based Ratemaking (PBR) would impact reliability. While the definitions of SAIDI and SAIFI presented in the decision remain accurate, much of the discussion contained in the decision is no longer relevant.

In its Rebuttal testimony, SCE discusses why it believes it is reasonable to exclude cable replacements undertaken under the Oil Switch Replacement program (74 circuit miles per year) from its Quanta reliability study, stating that the cables that are replaced are very reliable and will have limited reliability impacts; DRA is therefore wrong to suggest that this omission casts a shadow on the analysis performed by Quanta.

In response to these allegations, DRA would like to point out that in SCE's Rebuttal testimony, SCE acknowledges that the replacement of the cables associated with the oil switches "will have some reliability benefits."[362] SCE has forecasted that 74 miles of this cable will be replaced each year, and DRA has accepted this forecast. By 2030, nearly 1,500 miles of this cable will have been replaced. Surely, if replacing 74 miles will have "some reliability impact," replacing nearly 1,500 miles will have an even greater impact. DRA never stated that that the cable replacements associated with the oil switches would have the same reliability impact as the other types of cable replacements. All DRA said in its testimony was that it is erroneous to assume that omitting such volumes of oil switch cables will have no impact on SAIDI and SAIFI. In its Rebuttal testimony, SCE has now confirmed this. SCE went to great lengths to determine the future reliability of its underground system, going so far as to retain an outside consultant (Quanta) to perform this analysis. Clearly, the reliability results derived by Quanta overstate the reliability degradation that will occur by 2030. Since nearly 1,500 miles of oil switch-related cables were omitted from Quanta's study, the inclusion of those cables would unquestionably improve the reliability figures that Quanta has derived.

SCE's next Rebuttal allegation is that in the last GRC, SCE was only authorized to replace 89 miles of underground cable in 2009, 1/3 of what it had requested for cable replacements. Therefore, recommendations for future low investments based on previous low investments are a self-fulfilling prophesy.

---

[362] Ex. SCE-18, Vol. 3, Part 3 and 5, p. 28, line 5.

DRA is frankly puzzled by this portion of SCE's Rebuttal testimony. SCE's Rebuttal seem to suggest that DRA has somehow factored-in or utilized previous low levels of authorized cable replacements to derive its future forecasts. This assumption is factually incorrect. DRA did not trend or average prior replacement amounts to derive its forecasts. In fact, nowhere in DRA's testimony is there a mention of the 89 circuit-miles that were authorized for replacement in 2009. DRA's testimony shows the 270 circuit-miles of cable that SCE actually replaced in 2009, not the 89 circuit-miles that were authorized.[363] DRA accepted SCE's replacement forecast for 2011, and recommended a large increase for 2012. DRA's recommended 2012 replacement forecast of 350 circuit-miles is much larger than any previous year, including the 270 miles that were actually spent in 2009 and the 267 miles SCE forecasts for 2011. In no way is DRA's 2012 recommendation the result of a self-fulfilling prophesy involving previously authorized replacement levels.

SCE's last Rebuttal allegation is that the low levels of cable replacement in the past cannot meet the future demands of SCE's aging distribution system. DRA does not take issue with this statement, which is why DRA has recommended that 350 circuit-miles of underground cable be replaced in 2012. This is a far greater quantity of cable replacement than any prior year, including the 267 circuit-miles that SCE itself recommends for 2011. Where DRA does take issue with SCE is in the magnitude of the increase for 2012 and beyond. The bottom line is that a balance must be struck between capital expenditures and reliability. Even SCE acknowledges that reliability will suffer, even using its own forecasts for cable replacements. SCE is using its judgment to strike a balance between expenditures and reliability. Using its judgment, DRA has concluded that it is reasonable (and to the ratepayers' advantage) to slightly decrease the reliability of SCE's system by the year 2030 in order to save many hundreds of millions of dollars between now and 2030. DRA's recommendation would cause the average customer to experience one additional outage less than once every 7+ years by the time 2030 arrives.[364]

5.5.2. Cable in Conduit (CIC) Replacement

Regarding its Cable-In-Conduit (CIC) Replacement program SCE states that in the 1960s, it began installing a type of underground cable that was loosely housed inside a plastic

[363] Ex. DRA-6, p. 24, Table 6-3.

[364] Ex. DRA-6, p. 31.

pipe. This so-called Cable-In-Conduit (CIC) eventually developed corrosion problems, and has proven to be unreliable. SCE estimates that it has over 10,000 conductor-miles of this CIC-type cable, and it wants to begin proactively replacing it.[365]

SCE often experiences difficulties when it attempts to replace this type of cable. Frequently, the cable binds up inside the pipe that surrounds it, and it cannot be removed. SCE states that better equipment and better methods of removal must be developed if the replacement of this quantity of cable is to be made affordable.[366] The capital expenditures that SCE is requesting for this project through 2014 will be used for a pilot program to investigate new approaches for replacing this cable.

DRA does not object to the creation of a pilot program. As the CIC-type cable continues to age, more and more failures will likely occur. SCE and its ratepayers would want these replacement costs to be as economical as possible. SCE's testimony shows that SCE began funding this pilot program in 2009, having spent $0.932 million.[367] SCE spent an additional $4.030 million in 2010.[368] However, beginning in 2011, SCE is requesting a dramatic increase in the capital expenditures for this pilot program. SCE is requesting $13.357 million for 2011 and $30.560 million in 2012.[369]

The Oxford dictionary defines the word "pilot" to be "*an experimental undertaking or test, especially in advance of a larger one.*" In DRA's judgment, SCE's requests for 2011 and 2012 go beyond what is necessary for an "experimental undertaking or test." It is important to carefully determine the most efficient and economical method to replace the CIC-type cables; that is, after all, the purpose of having this pilot program. SCE's request to greatly expand its expenditures in 2011 and 2012 suggests that SCE will be "locking in" a methodology before the pilot program is completed in 2014. DRA recommends that the $4.030 million spent in 2010 should be carried forward (with yearly escalation) into 2011 and 2012. Before SCE dramatically increases the level of capital expenditures for the CIC replacements, it should be certain that it has determined the most efficient way to undertake these replacements. This pilot program can

---

[365] Ex. SCE-3, Vol. 3, Part 3, Chapters I-II, p. 34.

[366] Ex. SCE 3, Vol. 3, Part 3, Chapters I-II, p. 36, lines 2 and 3.

[367] Id. at p. 37.

[368] Ex. DRA-6, p. 5, Table 6-1.

[369] Id.

then be evaluated in the next GRC. DRA forecasts $4.102 million in 2011 and $4.201 million in 2012 for capital expenditures for the CIC Program. DRA's recommendations result in a reduction to SCE's forecasts of $9.255 million in 2011 and $26.359 million in 2012.[370]

In its Rebuttal testimony, SCE criticized many aspects of DRA's recommendations. SCE's first allegation is that DRA's proposed expenditure levels are so small that they will be incapable of providing adequate levels of information. DRA's recommendations are equivalent to only 2 CIC projects per year.

SCE began capital expenditures for this project in 2009. SCE states in its Rebuttal testimony that "only" 2 CIC projects would be conducted each year using DRA's recommended expenditure levels. However, over the 5-year cycle through the attrition years (2010 through 2014), SCE would be able to undertake 10 separate CIC replacement trials. Compare this to SCE's proposal. As SCE states in its Rebuttal, SCE's wants to fund 15 projects per year.[371] Using the same 5-year cycle, that is sufficient to undertake 75 separate projects. How many projects does SCE need to undertake during this pilot period to determine the most efficient/economical way to replace the CIC-type cables? Clearly, DRA's recommendation is a more realistic and reasonable way to proceed with this pilot program.

SCE's next allegation is that DRA is wrong in characterizing the CIC Replacement Program as only a fact-finding pilot. SCE also wants to address current problems and ramp up the resources and processes necessary to address the enormous challenges ahead.

DRA has several problems with SCE's allegations. First, in its testimony, SCE described this program as a "pilot",[372] and DRA has used the same terminology. However, obviously worried about its lack of support for dramatically increasing its capital expenditure request for a "pilot" program, SCE, in its Rebuttal, re-characterizes DRA's testimony stating that "DRA Is Wrong To Characterize The CIC Replacement Program As Only A Fact-Finding Pilot". SCE's statement is blatantly false. At no point did DRA describe this pilot program as "only a fact-finding pilot". At no point did DRA use the word "only" in conjunction with the pilot program. SCE is now trying to put feathers on a rather drab hat in order to make it more appealing. Second, SCE now states that it wants to "address current problems." Does this mean that SCE

[370] Ex. DRA-6, p. 32.

[371] Ex. SCE-18, Vol. 3, Parts 3 & 5, p. 8.

[372] Ex. SCE-3, Vol. 3, Part 3, Chapters I-II, p. 36.

wants to undertake CIC projects that do not provide information regarding the most efficient/economical way proceed? SCE has not clearly explained exactly what it is proposing to now do.

Lastly, SCE states that it wants to ramp up its resources and conduct a meaningful volume of preemptive replacements now. This is exactly what DRA has concluded would be a misuse of resources. At this stage of its investigation, SCE does not know how best to undertake these CIC replacements. To undertake these replacements now, before the pilot program is complete and the various replacement options are evaluated, virtually guarantees that the projects will not be performed in the most economical manner. This is precisely why DRA has recommended reductions to SCE's forecasts until after the pilot period has been completed.

Continuing in the same vein, SCE next states that it will not "lock in" any CIC replacement methodology, contrary to what DRA alleges in its testimony. However, in DRA's opinion, SCE's discussions in its Rebuttal testimony belie the statement that SCE will not "lock in" any CIC replacement methodology. In its Rebuttal, SCE states that it wants to effect "a meaningful volume of preemptive replacements now."[373] Undertaking a CIC replacement project now, before the results of the pilot program are complete and the various replacement options are evaluated, is "locking in" an inefficient/uneconomical methodology for that project. This is precisely the type of situation that DRA was attempting to avoid, and why DRA has recommended reductions to SCE's forecasts until after the pilot period has been completed.

SCE's last allegation is perhaps the most serious. SCE states that DRA has ignored the public safety aspect of the aging CIC and that stray voltages, caused by corroded concentric neutral wires, are a potential safety hazard.

DRA is acutely aware that any energized facility, not just CIC-type cables, can potentially cause severe injuries if not treated with caution and respect. This CIC pilot program is meant to develop efficient and cost effective procedures whereby these cables can be replaced. By first determining the most economical and most efficient manner to undertake these projects, SCE can then undertake these replacements in the most expeditious method possible, thereby removing the most problematic cables. It is important to remember that that this is a pilot program that involves proactive replacements – replacements that take place before the cable actually fails. Any CIC-type cable that is exhibiting voltage leaks should be repaired/replaced

[373] Ex. SCE-18, Vol. 3, Part 3 & 5, p. 19.

immediately because it has obviously already failed. That type of emergency situation is not the type of proactive replacement that is typically covered in this capital project category. Nevertheless, DRA's recommendation does provide for 5 miles of CIC replacement in 2012 as part of SCE's pilot program. DRA would expect that SCE would target for proactive replacement those sections of cable that it suspects are most likely to develop safety issues in the future. It is also important to note that SCE is only now proposing this program, and only began spending money in 2009. DRA believes that the preemptive replacement of cables is useful, but does not believe that a sudden dramatic increase in the CIC program has been justified.

5.5.3. A and B Bank Transformers

Transformers are major pieces of equipment that are used to change the voltage of electricity. Transformers are used to increase voltage in order to reduce energy losses during transmission over long distances. Conversely, they are also used to reduce voltage to a level that is usable to SCE's customers. A-bank transformers are located in major substations where they take high voltage electricity and typically transform it down to 66 kV. B-bank transformers are located in neighborhood substations where they transform 66 kV electricity down to a level that can be sent out into the distribution circuits.[374]

SCE includes a table in its Direct Testimony, that provides historical data regarding A-bank transformers.[375] According to that table, the number of A-bank replacements scheduled for 2011 and 2012 seems to be consistent with the number of replacements that have occurred in prior years. Similarly, the unit costs for these transformers appear to be reasonable. Therefore, DRA is not recommending any adjustments to SCE's A-bank forecasts.

The details for SCE's proposed B-bank transformer replacements are also provided in SCE's Direct Testimony.[376] As shown in its testimony, SCE has historically preemptively replaced between 4 and 14 transformers each year. For 2010, SCE estimated that it would replace 20 transformers; the actual recorded number was 14.[377] SCE is estimating that it will replace 16 B-bank transformers in 2011. This is slightly higher than what has occurred

---

[374] Ex. SCE-3, Vol. 3, Part 3, Chapters I-II, p. 67.

[375] Id. at p. 70.

[376] Ex. SCE-3, Vol. 3, Part 3, Chapters I-II, p. 70, Table II-20.

[377] Ex. DRA-6, p. 33, citing Response to Data Request DRA-199-GAW, Question 1.b.

historically, but appears reasonable to DRA. However, in 2012, SCE's replacement estimate jumps to 40, nearly three times higher than the previous highest recorded replacement level.[378]

SCE derives a theoretical replacement level of 45 transformers per year based on a probability of failure curve.[379] This number is apparently used to justify SCE's estimate of preemptively replacing 40 transformers in 2012. DRA notes several important points regarding SCE's proposal. First, SCE's statistical derivation of 45 transformer failures per year is subject to variation from year to year. As SCE notes, 33% of the B-bank transformers are older than the mean wear-out time, and 270 are older than 80 years.[380] There is obviously no way to know with certainty how many transformers will fail in any given year. In none of its forecast year estimates (through 2014) is SCE proposing to preemptively replace 45 transformers.

DRA's second point is that these are preemptive replacements. As mentioned previously, all the capital projects included under the Infrastructure Replacement Program (including the A and B-bank transformer replacements) seek to replace pieces of equipment prior to their failure based on a risk/reliability evaluation. Stated another way, these programs preemptively replace pieces of equipment that are still operational, based on various studies that show they may soon fail. The cost of "in service" failures (pieces of equipment that fail while they are still being used) is not included as part of the forecasts for this capital program. Combining these two points leads to the following conclusion: the number of B-bank transformers failing each year cannot be predicted with any certainty, and even if they could, SCE is not attempting to eliminate all in service failures since it is proposing to preemptively replace fewer transformers than it predicts will fail (40 replacements versus 45 predicted failures).

DRA tends to be cautious when utilities request sudden dramatic increases for capital expenditures in the test year. SCE's proposed 2012 capital expenditures are much higher than the historical trend, indicating that SCE is indeed requesting those types of dramatic test year increases.[381] For this particular capital category, the fact that SCE has never recorded more than 14 B-bank capital replacements indicates that SCE does not consider the preemptive replacement

---

[378] 40 replacements (in 2012) ÷ 14 replacements (previous highest) = 2.86.

[379] Ex. SCE-3, Vol. 3, Part 3, Chapters I-II, p. 76.

[380] Ex. SCE-3, Vol. 3, Part 3, Chapters I-II, p. 76, lines 3 through 5.

[381] Ex. DRA-6, p. 5, Table 6-1.

of B-bank transformers to be an urgent matter; if it did, SCE would have replaced more than 14 in 2010, and may have requested more than 16 replacements in 2011.

SCE has not shown why 40 replacements are reasonable for 2012. Assuming that SCE actually replaces the 16 B-bank transformers it forecasts for 2011, the jump to 40 replacements in 2012 represents a 150% increase over the 2011 level.[382] DRA's recommended number of replacements for 2012 is 30, considerably lower than SCE's request but much higher than any other recorded year. In DRA's judgment, this is a reasonable estimate and represents a very large increase over SCE's estimate of 16 in 2011. DRA's recommended increase (to 30 replacements in 2012) represents an 87.5% increase over the prior year.[383] DRA's recommendation reflects the uncertainty in the actual number of B-bank transformers that are likely to fail, yet recognizes SCE's concern that increasing levels of preemptive replacements are warranted due to the increasing age of the B-bank population.

As shown in SCE's testimony, once a reasonable level of B-bank transformer replacements is derived, the last step in calculating a total cost is to multiply the number of replacements by the unit costs. DRA has reviewed the unit costs shown in SCE's testimony and finds them reasonable.[384] Therefore, the only difference between SCE's and DRA's estimates for total costs for this capital category is that DRA has a lower estimate for 2012 replacements. By reducing the number of B-bank replacements from 40 to 30, DRA's recommended 2012 capital expenditure forecast for A and B-bank transformer replacements is $10.622 million lower than the comparable SCE estimate.[385]

In its Rebuttal testimony, SCE alleges that DRA has misinterpreted SCE's effort to avoid requesting more replacements than necessary as SCE's indifference to avoid all failures.[386] In response, DRA would like to state that it understands what SCE was attempting to do. As DRA points out in its testimony, there is much uncertainty in attempting to predict future failures – SCE acknowledges this in its Rebuttal testimony.[387] DRA never stated and never assumed that

---

[382] The formula for this calculation is: [(40 – 16) ÷ 16] x 100 = 150%

[383] The formula for this calculation is: [(30 – 16) ÷ 16] x 100 = 87.5%

[384] Ex. SCE-3, Vol. 3, Part 3, Chapters I-II, Table II-21.

[385] Ex. DRA-6, p. 5, Table 6-1.

[386] Ex. SCE-18, Vol 3, Part 3 & 5, p. 11.

[387] Id.

SCE was indifferent to the avoidance of all failures. The only point DRA was trying to make was that the failure uncertainty even extended to SCE, as it was not requesting to replace the number of transformers that it predicted would fail.

SCE also alleges that its forecast for B-Bank transformer replacements was based on an objective analysis of transformer failure records and the age distribution of its current transformer population.

DRA assumes that the implication in the above statement is that DRA does not have a firm basis for its recommendation. This, of course, is not the case. DRA spent considerable time studying this issue. DRA understand why SCE believes that the aging population of transformers is likely to cause an increase in failures; DRA also understands why SCE would like to preemptively replace these transformers before they fail. However, nothing in SCE's testimony or workpapers persuaded DRA that a nearly 3-fold increase in replacements (from 14 in 2009 and 2010 to 40 in 2012) was reasonable. Stated another way, SCE never explained or justified the sudden need for such a large increase. DRA's forecast of 30 replacements in 2012 reflects the uncertainty in the actual number of transformers that will fail, yet recognizes SCE's concerns regarding aging equipment.

5.5.4. Distribution Circuit Breakers

Circuit breakers perform the vital task of shutting off the flow of electricity to a circuit that encounters a "fault." When a conductor comes into contact with the ground, such as with a downed wire, a circuit breaker stops the flow of electricity. If these faults are left uncorrected, massive amounts of current will be drawn through the downed wire, possibly destroying cables, switches, and transformers located above the fault, and posing a safety risk to anyone who comes into contact with a live wire.[388]

SCE has 10,411 distribution circuit breakers in its system. In its Direct testimony, SCE provides a calculation that shows that with an average age of 28 years, an estimated 75 breakers will fail each year based on a probability of failure curve. SCE is proposing to preemptively replace far more breakers each year than the 75[389] that it predicts will fail. SCE also wants to

[388] Ex. SCE-3, Vol. 3, Part 3, Chapters I-II, p. 79, lines 6 through 9.

[389] Id., at p. 82.

begin replacing breakers that are no longer supported by the original manufacturer, and are consequently difficult to maintain because of a scarcity of spare parts.

To help with its analysis of this capital program, DRA prepared Table 6-5, which is included in DRA's testimony.[390] As can be seen on that table, there are three categories of distribution circuit breakers: 115 kV, 66 kV, and 12 kV. SCE estimates different levels of replacements for each category, and has derived different unit costs for each. For the years 2005 through 2009, SCE did not provide details regarding the breakdown for breaker replacements or unit costs. It did provide the total number of breakers replaced each year, as well as the total cost.

DRA began its analysis by examining SCE's estimates for total breaker replacements.[391] In DRA's judgment, SCE's estimate of 147 total circuit breaker replacements in 2011 is reasonable; it is of the same magnitude as previous replacements, and is actually slightly less than the 159 replacements that occurred in 2009. However, as with other capital programs previously discussed, SCE is proposing a large increase for the test year. As mentioned earlier, SCE estimates that 75 circuit breakers will fail each year, yet SCE is estimating 215 replacements for 2012. DRA pays special attention to test year estimates that show sudden dramatic increases for capital expenditures as compared to the previous year. For this particular capital category, the fact that SCE has never recorded more than 159 distribution circuit breaker replacements indicates that SCE does not consider the preemptive replacement of these breakers to be an urgent matter; if it did, SCE would have proposed to replace more than 62 in 2010, and would likely be requesting more than 147 replacements in 2011.

DRA understands SCE's desire to begin replacing breakers that are no longer supported by the original manufacturer; when spare parts are no longer being produced, breakers can be difficult and expensive to maintain. Nevertheless, SCE has not shown that it is reasonable to preemptively replace 215 circuit breakers in 2012. Assuming that SCE actually replaces the 147 breakers it forecasts for 2011, the jump to 215 replacements in 2012 represents a 46% increase over the 2011 level.[392]

---

[390] Ex. DRA-6, p. 37, Table 6-5.

[391] Id. column m.

[392] The formula for this calculation is: $[(215 - 147) \div 147] \times 100 = 46.26\%$

DRA's recommended number of replacements for 2012 is 175, considerably lower than SCE's request but higher than any other recorded year. In DRA's judgment, this is a generous and large increase over SCE's estimate of 147 in 2011. This estimate reflects 100 more breaker replacements than SCE expects will actually fail (175 replacements recommended by DRA versus the 75 that SCE is forecasting will fail each year), and is 10% higher than the highest previous number of replacements (159 in 2009).[393] DRA's recommended increase (to 175 replacements in 2012) represents a 19% increase over the prior year.[394]

Once a reasonable forecast for the total number of distribution circuit breakers has been determined, it is necessary to distribute that amount among the three categories of breakers.[395] Theoretically, these total replacements can be distributed in any number of ways. However, for the 115 kV and the 66 kV breakers, SCE's forecasts for replacements are remarkably constant over the period 2011 through 2014, and are actually less than the 2010 forecast.[396] DRA does not object to these estimates, which means that DRA's recommended decrease in the total number of 2012 replacements must be reflected in the 12 kV category.[397] DRA's recommended forecast for 12 kV breaker replacements in 2012 is 153. This number is mathematically derived, and is simply the number that, when added to the 115 kV estimate (7 replacements) and the 66 kV estimate (15 replacements) equals the total estimate for circuit breaker replacements (175 replacements).[398]

With the yearly number of circuit breaker replacements determined for each of the three categories, the last step in this calculation is to multiply the number of replacements by the unit costs. DRA accepts SCE's unit cost estimates. Therefore, all the pieces needed for the calculation are known. The only difference between SCE's and DRA's estimates for total costs for this capital category is that DRA has a different (lower) estimate for replacements in 2012 for 12 kV circuit breaker replacements. After reducing the number of 12 kV replacements, the resulting calculation causes DRA's recommended 2012 capital expenditure forecast for

---

[393] The formula for this calculation is: [(175 – 159) ÷ 159] x 100 = 10.06%

[394] The formula for this calculation is: [(175 – 147) ÷ 147] x 100 = 19.05%

[395] Ex. DRA-6, p. 37, Table 6-5.

[396] Ex. DRA-6, p. 37, Table 6-5.

[397] Id. column j.

[398] Id. columns b, f and n.

distribution circuit breaker replacements to be $3.564 million lower than the comparable SCE estimate.[399]

In SCE's Rebuttal testimony, SCE alleges that the target of SCE's distribution circuit breaker replacement program is the oldest of those breakers manufactured by companies no longer in business, making those breakers difficult, if not impossible, to maintain.[400]

DRA certainly understands SCE's concerns regarding the maintenance of aging circuit breakers. However, prior to 2012, the highest number of yearly circuit breaker replacements occurred in 2009, when 159 breakers were preemptively replaced. DRA is accepting SCE's 2011 forecast (147 replacements), and is recommending 175 replacements for 2012. SCE completely fails to explain how 147 replacements can be adequate in 2011, yet 175 replacements in 2012 will (according to SCE) incur reliability and safety risks. DRA's 2012 recommendation represents a 19% increase over the previous year, and reflects 100 more breaker replacements than SCE expects will actually fail (175 replacements versus 75 that will fail). SCE's distribution circuit breakers will not suddenly "grow old" in 2012; the aging process takes place gradually, year after year. Common sense would dictate that if 147 replacements (SCE's own estimate) were adequate in 2011, 175 replacements would be more than adequate in 2012. The Commission should not be unduly swayed by SCE's aging infrastructure arguments.

5.5.5. 4 kV Cutovers

SCE has approximately 4,800 electrical circuits in its system, roughly 1,100 of which are operating at a voltage of 4 kV (or less). The design standards for these circuits were originally developed over a century ago when electrical consumption by each customer was much lower than it is today. SCE states that by today's standards, 4 kV circuits are inefficient, requiring more amps to supply the same amount of power as a more modern circuit.[401]

As load growth continues in its system, SCE has developed a process whereby customers on the outer edges of a 4 kV circuit are transferred to neighboring (larger) circuits. The net result of this "cutover" program is that the load on the 4 kV circuits is reduced to a level that is within its capacity. Of all the scenarios available to handle this problem, SCE states that the 4 kV

---

[399] Ex. DRA-6, p. 5, Table 6-1.

[400] Ex. SCE-18, Vol. 3, Part 3, p. 11.

[401] Ex, SCE 3, Vol. 3, Part 3, Chapters I-II, pp. 83-87.

cutover program is by far the most cost effective way to handle the problem of increasing loads on these older circuits.[402]

SCE provides a table in its Direct testimony to show how the costs for the cutover program are derived.[403] As can be seen on that table, the computational mechanics for calculating the yearly costs are quite simple – it is simply a matter of multiplying the yearly forecast of the number of amps (that will be transferred to neighboring circuits) by the annual cost per amp. DRA has looked closely at SCE's estimates for both the numbers of amps being transferred and the costs per amp. DRA concludes that the costs per amp are reasonable and is not recommending any changes to those estimates. However, as described below, DRA does have some concerns regarding the reasonableness of the forecasts for the number of amps being transferred.

SCE discusses two of the cutover milestones that it alleges are critical to maintaining reliability. The first milestone is that SCE wants to transfer 16,330 amps from its most heavily loaded 4 kV circuits "as soon as possible."[404] SCE does not define the term "as soon as possible." However, by examining SCE's Table II-24 and summing the transfer estimates in the second column of data, the 16,330 figure is not reached until 2014.[405] SCE's second milestone is to transfer an additional 11,194 amps from overloaded 4 kV circuits by the year 2020. Combining these two milestones, SCE would like to transfer 27,524 amps by the year 2020.[406] In order to analyze all this information, DRA created its own Table 6-6, which is included in DRA's testimony.[407]

---

[402] Ex. SCE-3, Vol. 3, Part 3, Chapters I-II, p. 89, line 26 and 27.

[403] Ex. SCE-3, Vol. 3, Part 3, Chapters I-II, p. 90, Table II-24.

[404] Ex. SCE-3, Vol. 3, Part 3, Chapters I-II, p. 91, lines 2 through 4.

[405] Ex. SCE-3, Vol. 3, Part 3, Chapters I-II, Table II-24: the second column of data shows the number of amps that SCE wants to transfer each year. Through the year 2013, the sum of the proposed transfers totals 15,876 amps. Therefore, the milestone of 16,330 will be reached sometime in 2014.

[406] 16,330 amps (milestone 1 by 2014) + an additional 11,194 amps (milestone 2 by 2020) = 27,524 total amps.

[407] Ex. DRA-6, p. 41, Table 6-6. Table 6-6 rearranges some of the data contained in SCE's Table II-24, and adds a column (column d) that keeps a running total of the cumulative number of amps that have been transferred using DRA's estimates. Column d was added in order to determine whether both of SCE's milestones could be reached using different estimates for the yearly amp transfers. Unlike previous tables, DRA has extended this one out to the year 2020. This was done in order ascertain whether milestone 2 would be reached by that year. It should also be noted that historical data is not included in Table 6-6.

In a data request, DRA asked that SCE provide the number of amps that had been transferred in previous years. SCE responded that that information was not readily available.[408]

SCE's proposed number of amps to be transferred in 2011 is only slightly higher than the 2010 estimate.[409] Because recorded data were not provided, DRA was unable to compare these estimates with recorded amounts. Nevertheless, the closeness of the two estimates gives DRA some degree of confidence that these numbers are reasonable, and DRA is accepting SCE's estimate.

However, the estimate for 2012 is another story. Once again, SCE is proposing a sudden large increase for the test year, and once again, DRA views this proposal with caution. SCE's 2012 forecast of 5,168 amps to be transferred is a 71% increase over the 2011 estimate (3,019 amps).[410] In DRA's judgment, SCE has not justified such a large increase. DRA notes that SCE is not estimating increased transfers in 2011, indicating that cutting over 4 kV circuits is not a high priority.

Regardless of the priority one might assign to this capital program, DRA proposes an alternate replacement strategy that meets the two milestone goals of SCE, and has the added benefit of lowering costs. DRA sought to find a transfer strategy that met SCE's goal of transferring 16,330 amps by 2014 (milestone 1), as well as transferring a total of 27,524 amps by 2020 (milestone 2). DRA found that if 3,500 amps were transferred annually beginning in 2012, both milestones would be achieved.[411] The first milestone (of transferring 16,330 amps) occurs right on schedule in 2014.[412] The same is true for the second milestone (transferring 27,524 amps by 2020).[413] Clearly, the adoption of an annual transfer of 3,500 amps will meet (or exceed) both of SCE's milestones. Therefore, DRA recommends that 3,500 amps be used as the annual level of amps to be transferred.

---

[408] Ex. DRA-6, p. 42.

[409] Ex. DRA-6, p. 41, Table 6-6.

[410] The formula for this calculation is: [(5,168 – 3,019) ÷ 3,019] x 100 = 71.18%.

[411] Ex. DRA-6, p. 41, Table 6-6, column c.

[412] Ex. DRA-6, p. 41, Table 6-6, column c. The first shaded cell in that colun shows that 16, 501 amps will be transferred by the end of 2014.

[413] Ex. DRA-6, p. 41, Table 6-6. The second shaded cell in column d indicates that 30,501 amps will be transferred by 2018, two years prior to SCE's 2020 goal.

With the total amps transferred in place, it is a simple matter to multiply the annual transfers by the unit costs to obtain the total annual 4 kV cutover costs. DRA agrees with SCE's 2011 forecast, but is recommending a $9.734 million reduction for 2012 capital expenditures for the 4 kV Cutover program.[414]

In its Rebuttal testimony, SCE alleges that a previous lack of O&M funding for 4 kV cutovers has prevented SCE from conducting as many cutovers as it would like, and has put many customers at risk of blackouts. In response, DRA can only state that it is not privy to the Commission's decision-making process. DRA can only conclude that in the last GRC, SCE failed to convince the Commission that it needed the O&M levels that had been requested. Be that as it may, the past historical transfers of amps (and consequently the past level of O&M expenditures) did not play a role in DRA's transfer recommendations for this current GRC.

SCE next alleges that it needs to eliminate its backlog of overloaded 4 kV circuits not by 2014, but immediately. Despite that allegation, nothing in SCE's testimony or workpapers suggests that an immediate elimination of the backlog is even being contemplated by SCE. If SCE needs to eliminate its backlog of overloaded 4 kV circuits immediately, it has a funny way of showing it. In Direct testimony, SCE clearly discusses how it wants to transfer 16,330 amps "as soon as possible."[415] By looking at SCE's forecasts, it is possible to calculate that, using SCE's own forecast, 16,330 amps would be transferred by 2014. Neither the term "as soon as possible" nor the date of 2014 is equivalent to "immediately." Using a transfer schedule (3,500 amps per year) that is different from the schedule proposed by SCE, DRA was able to achieve all of the transfer goals that SCE discusses in its testimony. The Commission should not be confused by SCE's inappropriate use of the term "immediately."

5.5.6. 4 kV Substation Elimination

This section is analogous to the previous one. The main difference is that instead of transferring part of the load of 4 kV circuits, SCE proposes to transfer the entire load from 4 kV substations, thereby closing down those substations. This would eliminate the need to replace the equipment in the substations, which would then be removed.[416]

---

[414] Ex. DRA-6, p. 41, Table 6-6, row 24.

[415] Ex. SCE-3, Vol. 3, Part 3, p. 91.

[416] Ex. SCE-3, Vol. 3, Part 3, p. 93.

Because of the age of these 4 kV substations, SCE expects many failures in the near future. Rather than waiting for these failures to occur, SCE is proposing that the substations be preemptively replaced. SCE states that waiting for failures to occur, and then replacing the failed parts with modern equipment, is sometimes impossible because modern equipment is often larger and does not fit into the existing space.[417] SCE includes a table in its Direct testimony to show that beginning in 2012, SCE proposes to begin replacing these 4 kV substations; the first year of the replacement program is budgeted at $34.286 million.[418]

The 4 kV Substation Elimination Program is yet another example of SCE proposing a large test year increase to its capital budget. DRA has carefully reviewed the arguments SCE has put forward to support the commencement of this program. DRA understands and agrees with SCE's concerns. Nevertheless, DRA is recommending that the 4 kV Substation Elimination Program not be undertaken at this time. In spite of its arguments, in DRA's opinion, SCE has not presented any persuasive reasons that this program should begin now.

As an example of its concern, DRA recommends that Table II-27 in SCE's Direct testimony[419] be carefully studied. That table presents a partial list of the 4 kV substations that contain the oldest equipment. The first substation on the list is Carpinteria. That substation contains at least one transformer that is 97 years old, and at least one circuit breaker that is 53 years old. In this lengthy list of substations, the one with the youngest transformer is Beaumont, with at least one transformer that is 62 years old. The purpose of this discussion of Table II-27 is to point out that that aging 4 kV substations are nothing new. The transformers in the Carpinteria substation were probably considered to be old 30 years ago. The operational problems that SCE discusses in its testimony have not just suddenly appeared for the first time. In spite of these problems, SCE has managed to keep these old 4 kV substations running; SCE has not shown why it cannot continue to keep them running.

In a perfect scenario, DRA agrees that it might be desirable to begin replacing these old 4 kV substations. However, we do not live in an ideal world. The economy in California is depressed, and unemployment remains in double digits. Without compelling evidence that this

---

[417] Ex. SCE-3, Vol. 3, Part 3, Chapters I-II, p. 96, lines 5 through 7.

[418] Ex. SCE-3, Vol. 3, Part 3, p. 97, Table II-28.

[419] Ex. SCE-3, Vol. 3, Part 3, p. 95, Table II-27.

replacement program is absolutely necessary, and that it must begin in 2012, DRA cannot recommend that it be undertaken at this time.

DRA's recommendation that the 4 kV Substation Elimination Program not begin in 2012 results in a reduction of $34.286 million as compared to SCE's 2012 forecast.[420]

During his time on the stand, DRA's witness was asked a number of questions regarding the 4 kV Substation Elimination project. DRA was asked about the impact that "islanding" (the descriptive name given to a circuit that is surrounded by neighboring circuits of a higher voltage) has on reliability. The DRA witness was also requested to turn to page 104 of Exhibit SCE-3, Vol. 3, Part 3, Chapter I-II, and was asked about catastrophic failures that had occurred in these old substations.

DRA acknowledged that in a perfect world, it would be ideal to replace these old substations. These are all very serious issues, and DRA is treating them with the respect they deserve. It is clear that having substations with these sorts of operating constraints is not the ideal way to operate an electrical system. Nevertheless, DRA continues to have questions (and concerns) regarding SCE's claim that, starting in 2012, a new capital program is necessary to replace these 4 kV substations. As mentioned while on the stand, DRA wonders why the substations cannot continue to be operated the way they have been. It is important to remember that the issue of aging 4 kV substations is nothing new – these substations did not suddenly "grow old" overnight. Therefore, the problems associated with maintaining these old facilities did not suddenly appear overnight either. DRA's next question is related to the first: why is SCE able to successfully operate these substations in 2011, but cannot continue to operate them in 2012? SCE has not provided any explanation as to what exactly is changing in 2012 that causes these substations to no longer be operable. Lastly, DRA continues to be concerned over SCE's lack of explanation regarding why SCE has not initiated any replacements for these substations prior to 2012, especially if these substations are the safety/reliability hazard that SCE claims.

All of the ongoing substation problems that SCE lists in its testimony and Rebuttal are valid and of concern; DRA understands why SCE wishes to eliminate these substations. However, SCE is missing the point of DRA's testimony. DRA is not arguing that these problems do not exist – DRA is simply saying that the total elimination of these substations is

[420] Ex. DRA-6, p. 5, Table 6-1, line 25.

not the only solution to these problems. As DRA discussed on the stand, and as shown in SCE's Rebuttal, SCE has spent a little over $5 million so far in 2011 to maintain 15 of the 4 kV substations.[421] That cost is a lot less than the $34.286 million that SCE wants to spend in 2012 to replace the 7 substations that are included in the 4 kV Substation Elimination program.

Once again, it is important to remember that the issue of aging 4 kV substations is nothing new – these substations did not suddenly "grow old" overnight, and the problems associated with maintaining these old facilities did not suddenly appear overnight either. SCE has been successfully maintaining and operating these substations in spite of their age, and has presented no evidence why they cannot continue to do so. If these old 4 kV substations are beyond repair, why didn't SCE initiate this substation elimination program years earlier – why wait until 2012? DRA has no answer to that question. Again, DRA understands the reasons why SCE would like to eliminate these old facilities. However, in these tough economic times, the cost of the substation eliminations is simply too high. Without compelling evidence that this new replacement program is absolutely necessary, and that it must begin in 2012, DRA cannot recommend that it be undertaken at this time.

In its Rebuttal testimony, SCE makes several allegations concerning DRA's recommendations for this capital category. SCE first states that it is not proposing to begin spending money to address aging and obsolete 4 kV substations; SCE has been spending millions of dollars to replace worn-out 4 kV substations.

In response to this statement, DRA would like to state that it appears that SCE is engaging in linguistic gymnastics. In its Direct testimony, SCE states that it has "not had a formal program to systematically eliminate 4 kV substations, therefore no prior expenses have been recorded under this account."[422] In its Rebuttal testimony,[423] SCE clearly shows that there have been no expenditures for this program prior to its inception in 2012. Therefore, DRA is correct when it states that this program is beginning in 2012. The capital expenditures that SCE lists in its Rebuttal testimony are for the replacement of individual pieces of equipment in the substation (the type of ongoing replacements that are routine for the continued operation of any

[421] See Ex. SCE-18, Vol. 3, Part 3, p. 18, Table I-12.

[422] Ex. SCE-3, Vol. 3, Part 3, p. 97, lines 7-8.

[423] Ex. SCE-18, Vol. 3, Part 3, p. 14, Table I-8.

substation), not for the wholesale elimination of an entire substation. DRA reiterates that the 4 kV Substation Elimination Program is indeed a new area that SCE is requesting to begin in 2012.

SCE next alleges that 4 kV substation eliminations are a significant improvement in the use of ratepayer money. Rather than replace old obsolete and inadequate equipment with new obsolete and inadequate equipment, a better use of ratepayer money is to transfer all of the customers to modern circuits, and eliminate the 4 kV substations altogether.

DRA understands SCE's argument, but disagrees. In its Direct testimony, SCE presents a Table II-29, showing the 7 substations that it proposes to eliminate in 2012.[424] The cost of these 7 eliminations is $34.286 million, or nearly $5 million per substation. Turning to page 18 of its Rebuttal testimony, SCE provides Table I-12, which shows that so far in 2011, SCE has spent $5.116 million to maintain the operational capabilities of 15 different 4 kV substations. Stated another way, for roughly the cost of eliminating a single 4 kV substation, SCE has been able to maintain 15 existing 4 kV substations. DRA understands the reasons why SCE would like to eliminate these old facilities. However, in these tough economic times, the cost of the substation eliminations is simply too high. Without compelling evidence that this new replacement program is absolutely necessary, and that it must begin in 2012, DRA cannot recommend that it be undertaken at this time.

SCE next states that in DRA's testimony, it seems to be suggesting that old equipment is good; such a conclusion by DRA is illogical.

In response to this allegation, DRA would suggest that SCE has drawn the wrong conclusions from DRA's testimony. As DRA points in its Direct testimony, SCE's 4 kV substations contain some very old equipment, with some having operated for nearly 100 years. The point that DRA was trying to make was that the issue of aging 4 kV substations is nothing new – these substations did not suddenly "grow old" overnight. Therefore, the problems associated with maintaining these old facilities did not suddenly appear overnight either. As mentioned in DRA's testimony, the Carpinteria substation has at least one transformer that is 97 years old, yet SCE has continued to keep that substation operational. Again, the point here is not to celebrate the glory of old equipment, but to show that in spite of their age, SCE has consistently maintained the operational reliability of these substations, and has been doing so for

[424] Ex. SCE-03, Vol. 3, Part 3, p. 87.

decades. SCE presented no evidence in either its testimony or its workpapers to show that it cannot continue to do so in the future.

5.6. T&D – Engineering Design And Project Management, Operations and Maintenance Expenses - 560.220, 580.220

SCE forecast $14.480 million for its Engineering Design And Project Management expenses. SCE developed its forecast by utilizing its 2009 recorded adjusted expenses for Sub-Accounts 560.220, 580.220, 588.220 and 595.220 plus incremental expenses for proposed projects and work activities. The corresponding DRA estimate for SCE's Engineering Design And Project Management expenses is $11.894 million, which is $2.586 million less than SCE's forecast.

560.220 – Transmission/Substation Operations Supervision and Engineering

SCE forecast $9.823 million for Sub-Account 560.220 (Labor of $2.577 million and Non-Labor of $7.246 million) for its Transmission/Substation Operations Supervision and Engineering expenses.[425] DRA utilized a five year average (2005-2009) as a basis for its forecast of $7.563 million for SCE's Sub-Account 560.220. DRA's forecast is $2.260 million lower than SCE's forecast. DRA made a normalized adjustment to SCE's recorded adjusted historical expenses (2005-2009) of $0.369 million recorded in Sub-Account 560.220 for ratemaking purposes. DRA's adjustment was made to remove discretionary costs associated with SCE's employee recognition program Spot Bonuses and Awards to Celebrate Excellence Recognition Points (ACE), which are inappropriate to charge to ratepayers.[426] SCE's employee recognition programs provide no clear or identifiable benefit to ratepayers and are not necessary to operate the utility business.

SCE's forecast request includes additional funding of $850,000 for Substation Automation Software Development Program and work activities associated with its Transmission Line Rating Study.[427] SCE has embedded costs and additional funding is not required. SCE's recorded adjusted expenses recorded in Sub-Account 560.220 have increased

---

[425] Ex. SCE-3, Vol. 3, Part 5, Chapters I-II, page 49.

[426] Ex. DRA-5, p. 123, footnote 285: In SCE's response to DRA-SCE-064-TLG question 1-b and 7-a SCE provided spreadsheets, which included recorded adjusted expenses for 2005-2009 incurred for its employee recognition awards programs recorded to Sub-Account 560.220. DRA removed expenses totaling $368,802 from its test year estimate which was based on a five year average.

[427] Ex. SCE-3, Vol. 3, Part 5, Chapters I-II, page 53.

by $4.274 million between 2005 and 2009. DRA utilized a five year average due to the fact that SCE has embedded funding associated with its Transmission Line Clearance/Rating Study and completed projects that it can allocate to Sub-Account 560.220 to address its test year needs. DRA discovered that the majority of the funding that SCE was authorized in its TY 2009 GRC to address its Transmission Line Clearance Study has been excluded from SCE's 2009 recorded adjusted expenses recorded to Sub-Account 560.220[428]

In SCE's TY 2009 GRC, the Company requested $16.795 million or a 206.20% increase in its Sub-Account 563.100 over its 2006 recorded adjusted expenses of $5.485 million, claiming that the main driver of the increase was its $10.623 million request to address a Transmission Line Clearance Study on its bulk transmission and sub-transmission lines.[429] DRA discovered that of the $16.565 million[430] that the Commission authorized for Sub-Account 563.100 in SCE's TY 2009 GRC, SCE shows that it only incurred costs of $3.360 million to address its Transmission Line Clearance Study and incurred additional expenses of $2.733 million to perform other transmission work activities recorded to Sub-Account 563-100.[431] It is troubling

---

[428] Ex. DRA-5, p. 123, footnote 287: In SCE's TY 2009 GRC SCE requested funding of $10.623 million associated with its Transmission Line Clearance/Rating Study in Sub-Account 563.100 for a total forecast in that Sub-Account of $16.565 million. The Commission granted SCE's request and authorized $16.565 million for Sub-Account 563.100 (D.09-03-025 page 55 and 56) for SCE to address its work activities associated with its Transmission Line Clearance/Rating Study. In its TY 2012 GRC, SCE now records expenses associated with its Transmission Line Clearance/Rating Study to Sub-Account 560.220 and records expenses associated with Other transmission activities that were associated with Sub-Account 563.100 in its 2009 GRC to Sub-Account 563.160.

[429] Ex. DRA-5, p. 124, footnote 288: DRA's 2009 report on SCE's TDBU O&M expenses in Ex. DRA-05 page 22 through 25, and SCE's 2009 testimony in SCE-03, Volume 2, Part 2, Chapter VII page 46.

[430] Ex. DRA-5, p. 124, footnote 289: SCE's TY 2009 GRC request was shown as $16.795 million in SCE-3, Vol. 2, Part 2, Chapter VII, page 41 for Sub-Account 563.100, the Commission shows that it authorized $16.565 million (D.09-03-025 page 55 and 56).

[431] Ex. DRA-5, p. 124, footnote 290: In DRA-SCE-064-TLG question 7-d-1, DRA requested information relation to SCE's 2009 authorized amount associated with its Transmission Line Clearance Study to address the study, evaluation, and mitigation planning related to potential clearance issues on its transmission and sub-transmission lines. DRA asked "Provide the documentation that demonstrates all Sub-Accounts and total expenses where SCE recorded expenses relating to the $10.623 million". SCE responded in part that "SCE does not track authorized dollars in the format requested by this question" and referred DRA to its testimony and stated that "$2.925 million of expenses were recorded in 2009 in sub-account 560.220 for Transmission Line Rating Study". SCE later provided a supplemental response and revised the number to $3.022 million for the 2009 costs incurred for its Transmission Line Rating Study. In SCE's response to DRA-SCE-85-TLG questions 1-a, SCE stated "The 2009 authorized amount for Transmission Line Rating Study was $11.820 million in 2009 constant dollars. The 2009 recorded is $3.360 million, which is a portion of sub-account 560.220 in the 2012 GRC. The 2009 authorized amount for Other Transmission Activities was $6.761 million in 2009 constant dollars. The 2009

that of the $16.565 million the Commission authorized in SCE's TY 2009 GRC for Sub-Account 563.100, SCE's recorded adjusted 2009 expenses shown in its TY 2012 GRC testimony only identify $6.093 million (in 2009 dollars). SCE has approximately $12.488 million[432] in embedded funding that it has excluded from its 2009 recorded adjusted expenses associated with its authorized funding for its Transmission Line Clearance/Rating Study that it can utilize to address its test year needs for Sub-Account 560.220.

The Commission should not approve increased ratepayer funding for activities that already have costs embedded, and no additional funding is needed over DRA's test year estimate of $7.563 million.

580.220 – Engineering, Planning and Protection Studies

SCE forecast $1.125 million for Sub-Account 580.220 (Labor of $0.789 million and Non-Labor of $0.336 million) for its Engineering, Planning and Protection Studies expenses.433 SCE's forecast of $1.125 million is an increase of $0.327 million or 40.98% over 2009 recorded expenses of $0.798 million. DRA utilized SCE's 2009 recorded adjusted expenses as a basis and forecast $0.798 million for SCE's Sub-Account 580.220.

SCE's request is not justified when compared to its recent historical levels. SCE's expenses have declined each year between 2006 and 2009 from $1.288 million in 2006 to $0.798 million in 2009, a decrease in expenses of $0.490 million. Further SCE states "In D.89.12.057, the CPUC stated that if costs have shown a trend in a certain direction over three or more years, the last recorded year is an appropriate base estimate".[434] DRA agrees that since SCE's expenses have "shown a trend in a certain direction over three or more years" by declining each year, SCE's last recorded adjusted expenses of $0.798 million are sufficient for it to address its test year needs.

---

recorded is $2.733 million…"

[432] Ex. DRA-5, p. 125, footnote 291: In SCE's response to DRA-SCE-085-TLG question 1-a, SCE provided its TY 2009 GRC authorized amount for Sub-Account 563.100 in 2009 dollars as $18.581 million ($11.820 million for the Transmission Line Clearance Study and $6.761 million authorized for Other Transmission Activities). Note that of the $18.581 million authorized in SCE's TY 2009 GRC, SCE's recorded adjusted 2009 expenses include only $6.093 million. SCE does not provide any specific and verifiable detail on the recording of the balance of the $18.581 million amounting to $12.488 million which SCE has excluded from its TDBU O&M 2009 recorded adjusted expenses.

[433] Ex. SCE-3, Vol. 3, Part 5, Chapters I-II, page 49.

[434] Ex. SCE-3, Vol. 3, Part 5, Chapters, I-II page 57.

SCE claims that its requested increase is for additional funding of $327,000 for an analyst to "develop requirements for new procedures relating to 2012 NERC CIP revision standards" and contractors to review and classify substation drawings for upcoming 2012 NERC CIP revisions".[435] SCE has requested more than is necessary to address NERC CIP related activities. DRA discovered that the "total cost to hire contract engineers to review and classify substation drawings is $250,000" or $83,000 normalized over the three year period, however SCE requested a total of $750,000 ($250,000 each year) over the three year rate case cycle.[436] SCE should have $83,000 in embedded cost that it can allocate to address these work activities and its request for additional funding should be denied.

DRA learned in a meeting on February 10, 2011 between DRA and SCE that SCE has embedded costs in its historical expenses for these activities due to the fact that SCE has been performing activities associated with NERC CIP requirements and revised standards for several years.[437] DRA also learned in that meeting that SCE has not specifically tracked all the related costs that are embedded in its TDBU historical expenses, and therefore is not able to accurately calculate expense increases to justify additional funding. It is unreasonable for SCE to request additional ratepayer funding, claiming that expenses are increasing, when it is not able to properly track and calculate historical expenses associated with this activity and its request should be denied.

5.7. T&D – Customer-Driven Programs

Capital Expenditures

A large portion of the work undertaken by the Transmission and Distribution Business Unit is generated by requests from SCE's customers. Projects of this type fall into the Customer Driven Projects area. Examples of this type of work include installing new service connections for new customers, converting overhead lines to underground, and relocating facilities to accommodate customers.

---

[435] Ex. SCE-3, Vol. 3, Part 5, Chapters I-II, page 57 and 58.

[436] Ex. DRA-5, p. 127, footnote 296: In SCE's response to DRA-SCE-064-TLG question 8-c, SCE stated that "The total cost to hire contract engineers to review and classify substation drawings is $250,000".

[437] Ex. DRA-5, p. 127, footnote 297: An example of SCE requesting funding to address its NERC Critical Infrastructure project activities is in its 2009 GRC shown in D.09-03-025, page 234.

There are nine project categories that make up the Customer Driven Projects area.[438] Of these nine categories, DRA is recommending adjustments to three of them. Each of these proposed adjustments is discussed in the following sections. SCE presents its Customer Driven Projects testimony in Exhibit SCE-3, Volume 4, Part 1 and 2, Chapters I-II. SCE's Rebuttal testimony is presented in Exhibit SCE-18, Vol. 4, Parts 1 & 2. All references to SCE's Direct/Rebuttal testimony in the Customer Driven sections that follow refer to those specific SCE exhibits.

5.7.1. Rule 20A Conversions

Overhead power lines are converted to underground lines pursuant to several Tariff Rules, one of which is Rule 20A. Under that tariff, SCE's Rule 20A capital budget dollars are allocated to governmental agencies within SCE's service territory, and each agency has an allocation planning account. Because of the way this rule is governed, cities and municipalities are the main drivers of spending for this program. SCE states that it anticipates that conditions will remain generally similar for cities and municipalities from 2010 through 2014, and uses the amount last authorized by the Commission in the 2009 GRC ($29.507 million plus escalation) for its estimates of annual Rule 20A capital expenditures during the forecast period.[439]

DRA took a different approach with its analysis of this capital program. Decision Nos. 73078 and 82-01-018 in Case 8209 require SCE to file an annual underground conversion report with the Commission every March. DRA asked SCE to provide copies of this report for the three previous years, and to provide a copy of the 2010 report when it became available. SCE furnished the requested materials, and DRA carefully reviewed them.

As part of these filings, SCE includes a table showing the accounting reconciliation of its Rule 20A expenditures. DRA included copies of the earliest (2007) and the latest (2010) reconciliation tables in Appendix C of Exhibit DRA-6. Of particular interest to DRA are three lines on those tables. Line 3 shows SCE's total allocations for Rule 20A underground conversions from 1968 through the end of the reporting period. Line 8 shows the total amount of capital expenditures that have been made for conversions over the same period. Line 10 indicates whether SCE has spent more or less than its allocation. As part of its Rule 20A

---

[438] Ex. DRA-6, p. 5, Table 6-1.

[439] Ex. SCE-3, Vol. 4, Part 1 and 2, Chapters I-II, pp. 47- 48.

analysis, DRA reviewed how the line 10 balance had changed from 2007 to 2010. As can be seen in the 2007 report, line 10 shows that SCE had cumulatively spent $181.061 million less than its allocations during the period 1968 through 2007; in the 2010 report, that figure had increased to $204.293 million.[440]

In DRA's judgment, the growth in the line 10 balance indicates that SCE is continuing to overestimate the amount of Rule 20A funding it forecasts it will spend each year. DRA believes that SCE's forecasts for 2011 and 2012 will continue this pattern.

A visual inspection of SCE's recorded data indicates that Rule 20A expenditures are generally trending downward.[441] As mentioned earlier, SCE states that municipalities and cities are the main driver for this program. With all of the budgeting and economic issues currently occupying the attention of local governments, it is not surprising that less consideration is currently being given to underground conversion projects. As shown in Table I-17 of its testimony, SCE estimated that $30.050 million would be spent on Rule 20A expenditures in 2010.[442] However, the actual amount spent for 2010 was $21.942 million. Clearly, the pattern of SCE overestimating the amount of its Rule 20A expenditures is continuing.

As previously mentioned, SCE anticipates that conditions will remain generally similar for cities and municipalities from 2010 through 2014. This is one area where SCE and DRA agree; DRA does not anticipate that there will be a sudden surge in interest by local governments to undertake undergrounding projects. In DRA's judgment, using the 2010 recorded expenditure level of $21.942 million (plus yearly escalation) for the 2011 and 2012 forecasts for Rule 20A expenditures is reasonable. The use of DRA's lower estimates results in a reduction to SCE's forecasts for the Rule 20A Conversion program of $8.259 million in 2011 and $8.461 million in 2012.[443]

In its Rebuttal testimony, SCE alleges that expenditures for a Rule 20A project can span up to five years or more. SCE has committed to spend $161 million to complete Rule 20A

---

[440] Ex. DRA-6, pp. 46-47.

[441] Ex. DRA-6., p. 47, Table 6-7.

[442] Ex. SCE-3, Vol. 4, Part 1 & 2, p. 47.

[443] Ex. DRA-6, p. 5, Table 6-1.

projects already underway.[444] According to SCE, under DRA's proposal, a large number of these projects already underway would be delayed by another 2.5 years.

DRA has several responses to SCE's allegations. First, SCE neglects to mention that the $161 million committed in 2010 is actually a substantial decrease over the 2007 level. As shown in the report SCE cites, the 2007 commitment level was over $182 million, more than $20 million higher than the 2010 amount.[445] Stated another way, SCE has less of a commitment now than it did back in 2007.

Second, SCE provides no basis for assuming that projects will be delayed because of DRA's recommendation. Indeed, SCE's own Rebuttal testimony indicates that uncertainties surrounding the undergrounding policies of third parties have been, and will continue to be, responsible for delays.[446] SCE particularly mentions Verizon, and a change in Verizon' practice of undergrounding.[447] As costs are shifted from Verizon to the sponsoring city, the financial feasibility of these projects is called into question, resulting in "significant delays." Formal complaints have been filed with the Commission, which are still pending.

Third, past history, as well as current data, conclusively show that SCE consistently overestimates its Rule 20A expenditures. As mentioned in DRA's testimony, during the period 1968 through 2010, SCE has cumulatively spent $204.293 million less than it was allocated.[448] Current forecasts continue that pattern. In its testimony, SCE requested $30.050 million in 2010 for Rule 20A expenditures; actual recorded expenditures for that year were $21.942 million. Clearly, SCE's pattern of overestimating Rule 20A expenditures is continuing to the present day.

Fourth, as SCE notes in its testimony, cities and municipalities are the main drivers of spending for Rule 20A, and it is anticipated that conditions will remain generally similar from 2010 through 2014 for them.[449] Therefore, even according to SCE, it is reasonable to assume that the Rule 20A expenditures in 2010 are unlikely to change over the ensuing years. DRA agrees with this, and it is the basis of DRA's forecasts for 2011 and 2012.

---

[444] Ex. SCE-18, Vol. 4, Parts 1 & 2, p. 3.

[445] Ex. DRA-6, Appendix A, p. 66.

[446] Ex. SCE-18, Vol. 4, Parts 1 & 2, p. 4, lines 1 through 15.

[447] Ex. SCE-18, Vol. 4, Part 1 & 2, p. 4.

[448] Ex. DRA-6, p. 47.

[449] Ex. SCE-3, Vol. 4, Part 1 & 2, p. 48.

SCE next alleges that the impact of Verizon's policy change is temporary and that the unfortunate consequence of the DRA proposal is to extend the impact of a temporary problem into the future.[450] DRA disagrees with SCE's allegation.

Verizon's 2009 policy change involves a disputed alteration in the way Verizon pays for undergrounding costs. SCE states that Verizon has changed its longstanding practice of paying for the trenching costs associated with the installation of service laterals.[451] This change has resulted in more of the costs being shifted to the sponsoring cities or the affected property owner. As a result, significant delays have occurred as the financial viability of projects is evaluated, and negotiations with Verizon are conducted. In January of 2010, the City of Santa Barbara filed a formal complaint with the Commission against Verizon (Case 10-01-005). On December 16, 2010, the Commission issued D.10-12-046, which extended the statutory deadline for resolving the case until January 19, 2012. This dispute has been going on for well over 2 years, and still there is no resolution. Furthermore, a Proposed Decision (PD) on the Santa Barbara complaint was issued on March 7, 2011. In that document, the PD ruled in favor of Verizon, meaning that Verizon was not required to pay the trenching costs that the City claimed Verizon was obligated to pay. If the final decision adopts the language in the PD, Rule 20A undergrounding will be delayed even further as projects are reassessed.

It is clear that during the 2011 and 2012 test year period, significant undergrounding delays will continue to occur. SCE may characterize the Verizon issue as "temporary," but DRA is absolutely correct to assume that 2011 and 2012 Rule 20A undergrounding costs will be impacted by that policy change.

5.7.2. Rule 20B and 20C Conversions

Tariff Rule 20B provides for SCE's funds to be used to partially pay for undergrounding projects. Unlike Rule 20A, where the utility subsidizes the entire undergrounding project, Rule 20B subsidies only cover an amount equal to the cost of an equivalent overhead electrical system. Since a typical overhead system is usually only one-fifth the cost of an underground system, parties that request Rule 20B funding end up paying the majority of the undergrounding

[450] Ex. SCE-18, Vol. 4, Part 1 & 2, p. 4.

[451] Ex. SCE-18, Vol. 4, Parts 1 & 2, p. 4.

costs themselves. According to SCE, Rule 20B undergrounding projects typically arise when a developer of a new project wishes to remove existing overhead lines for visual appeal.[452]

In deriving its Rule 20B forecasts, SCE first develops combined estimates for the number of miles it believes it will underground each year for Rule 20B and Rule 20C (which is analyzed in the following section). Those figures are then multiplied by a yearly estimate of the cost per mile to accomplish the undergrounding. SCE then allocates a portion of the resultant capital forecasts to the Rule 20B capital program. Tables I-18 and I-19, of SCE's Direct testimony, show the details of SCE's calculations.[453]

DRA has studied the estimating approach used by SCE. While DRA understands the methodology, it does not believe that SCE's approach completely captures the impact that the slowdown in the economy has on the demand for undergrounding expenditures.

SCE's recorded expenditure data shows that Rule 20B spending decreased abruptly in 2008, with 2010 expenditures being particularly reduced.[454] As shown in SCE's Direct testimony, SCE originally estimated 2010 Rule 20B expenditures to be $25.830 million.[455] As the recorded data indicates, actual expenditures for 2010 were $15.078 million.[456] SCE's estimating methodology has not reflected the dramatic downturn in spending for 2010.

Undergrounding overhead lines in order to improve the visual impact of a project can, in many instances, properly be considered a discretionary expenditure. DRA is not surprised by the level of spending that occurred in 2010. With the slowdown in the California economy, and with unemployment in the state in double digits, it is understandable that Rule 20B undergrounding projects are not as prevalent as in the past, especially since the applicant is required to pay for much of the undergrounding cost. DRA recommends using the 2010 recorded level of $15.078 million (plus yearly escalation) as the forecast for 2011 and 2012; DRA does not expect 2011 and 2012 expenditures to vary significantly from 2010 levels. DRA's forecast of $15.348 million in 2011 and $15.716 million in 2012 results in recommended adjustments of

---

[452] Ex. SCE-3, Vol. 4, Part 1 & 2, p. 48.

[453] Id. at pp. 50-51.

[454] Ex. DRA-6, p. 5, Table 6-1.

[455] Ex. SCE-3, Vol. 4, Part 1 & 2, p. 51.

[456] Ex. DRA-6, p. 50, Table 6-9.

$11.699 million in 2011 and $18.702 million in 2012 to SCE's forecasts for the Rule 20B Conversion program.[457]

Rule 20C conversions differ from Rule 20B conversions only to the degree to which SCE subsidizes the undergrounding project. For Rule 20C, the requesting applicant pays the entire cost of the project. Rule 20C projects generally occur when an individual property owner wishes to remove existing overhead lines.

The SCE methodology described in the previous section to develop estimates for Rule 20B expenditures is the same methodology SCE uses to develop its Rule 20C forecasts; the only difference is that once the total estimates for the combined Rule 20B and 20C undergrounding costs are derived, the percentage of the total allocated to Rule 20C is lower.

As discussed in the prior section, DRA disagrees with SCE's estimating approach. While DRA understands SCE's estimating methodology, SCE's approach does not completely capture the impact that the slowdown in the economy has on the demand for undergrounding expenditures.

SCE's recorded capital expenditure data shows that Rule 20C spending decreased starting in 2008, with 2010 expenditures being significantly reduced relative to prior years.[458] As shown in SCE's Direct testimony, SCE originally estimated 2010 Rule 20C expenditures to be $8.610 million.[459] SCE's actual recorded expenditures for 2010 were $5.259 million.[460] SCE's estimating methodology has not reflected the dramatic downturn in spending for 2010.

As discussed above, undergrounding overhead lines in order to improve the visual impact of a project can, in many instances, properly be considered a discretionary expenditure. With the slowdown in the California economy, and with unemployment in the state in double digits, it is understandable that Rule 20C undergrounding projects are not as prevalent as they once were, especially since the applicant is required to
pay for all of the undergrounding cost. DRA recommends using the 2010 recorded level of $5.259 million (plus yearly escalation) as the forecast for 2011 and 2012; DRA does not expect 2011 and 2012 expenditures to vary significantly from 2010 levels. DRA's forecast of

---

[457] Ex. DRA-6, p. 5, Table 6-1.

[458] Ex. DRA-6, p. 50, Table 6-9.

[459] Ex. SCE-3, Vol. 4, Part 1 & 2, p. 51.

[460] Ex. DRA-6, p. 50, Table 6-9.

$5.353 million in 2011 and $5.482 million in 2012 results in recommended adjustments of $3.663 million in 2011 and $5.991 million in 2012 to SCE's forecasts for the Rule 20C Conversion program.[461]

In its Rebuttal testimony, SCE alleges that DRA's proposal to fund Rule 20B and 20C projects at the historic low levels recorded in 2010 is misplaced. SCE states that the issue is what will happen in 2011 and 2012, not what did happen in 2010. SCE cites to other DRA testimony, in which DRA agrees with SCE that the economy will improve,[462] meaning that Rule 20B and 20C spending will also increase.

DRA does not agree with SCE's conclusions. Rule 20B undergrounding projects typically arise when a developer of a new project wishes to remove existing overhead lines for visual appeal. Rule 20C projects generally occur when an individual property owner wishes to remove existing overhead lines. In both cases, the removal of overhead lines in order to improve visual impact can usually be considered a discretionary expenditure. Rule 20B applicants typically pay 80% of the undergrounding costs, while 20C applicants pay 100%. DRA, in Exhibit DRA-3, does agree that the economy is beginning to improve. However, that improvement is modest; it is likely sufficient to support the small increases that DRA has forecasted for Rules 20B and 20C in 2011 and 2012. Moreover, the increases being forecasted by SCE are huge – a 2010 Rule 20B expenditure of $15.078 million jumps to $34.418 million by 2012, while a 2010 Rule 20C expenditure of $5.259 million jumps to $11.473 million by 2012. In both instances, SCE is projecting increases exceeding 100%.

The California economy is still fragile; Rule 20B and 20C expenditures are still discretionary. In DRA's judgment, it is ludicrous to assume that economic conditions in California will improve to the extent that a greater than 100% increase is going to occur. When SCE used its estimating methodology to develop 2010 estimates for Rules 20B and 20C, its estimates greatly exceeded the actual expenditure amounts, indicating serious flaws in the methodology. As the old saying goes, "the proof is in the pudding" – SCE's methodology demonstrably produces flawed estimates, and those flaws are not being corrected, and will impact 2011 and 2012. Clearly, DRA's forecasts are much more reasonable, and are in line with a slowly improving fragile California economy.

---

[461] Ex. DRA-6, p. 5, Table 6-1.

[462] Ex. SCE-18, Vol. 4, Part 1 & 2, p. 5.

5.8. T&D – Inspection and Maintenance

Operations and Maintenance Expenses - 583.120, 584.120, 593.120, 594.120

SCE forecast $108.288 million for its Inspection and Maintenance expenses.[463] SCE developed its forecast by utilizing its 2009 recorded adjusted expenses for Sub-Accounts 583.120, 584.120, 594.120, and 593.120 plus incremental expenses for proposed projects and work activities. The corresponding DRA estimate for SCE's Inspection and Maintenance expenses is $98.281 million, which is $10.007 million less than SCE's forecast.

583.120 – Distribution Overhead Inspections

SCE forecast $9.431 million for Sub-Account 583.120 (Labor of $2.507 million and Non-Labor of $6.924 million) for its Distribution Overhead Inspections expenses.[464] SCE's Sub-Account 583.120 includes the following line items: Overhead Detail Inspections, Annual Patrols, and Distribution Wood Pole Intrusive Inspections. DRA utilized SCE's recorded 2009 data and a five year average as a basis for its forecast of $7.838 million for SCE's Sub-Account 583.120. DRA's estimate is $1.593 million less than SCE's forecast. DRA takes issue with SCE's line item for Distribution Wood Pole Intrusive Inspections of $5.533 million.

DRA utilized a five year average (2005-2009) as a basis and forecast $3.939 million for SCE's Wood Pole Intrusive Inspections recorded to Sub-Account 583.120. SCE's recorded adjusted expenses declined each year between 2005 and 2008, from $6.278 million in 2005 to $1.568 million in 2008. SCE states that the decline in expenses was due to reductions in activities associated with identifying and scheduling poles for inspection, reductions in activities associated with its "no access" program, and reductions in the number of intrusive inspections performed.[465] In 2009, SCE's expenses increased by $4.442 million or 282.02% over 2008

---

[463] Ex. SCE-3, Vol. 4, Part 2, Chapters I-II, page 61.

[464] Ex. SCE-3, Vol. 4, Part 2, Chapters I-II, page 87.

[465] Ex. SCE-3, Vol. 4, Part 2, Chapters I-II, page 79 to 80. SCE's actual number of intrusive inspections performed declined due in part to an increase in recorded corrections. A recorded correction happens when an SCE inspector goes to the location to complete a wood pole intrusive inspection and finds that 1) there is no longer a pole at that location, 2) the pole has already been inspected, and 3) the pole has been recently replaced (DRA-SCE-065-TLG question 5-d). DRA notes that more accurate recording and documentation by SCE on when actual wood pole intrusive inspections were performed and the exact location, when wood poles were removed, and when wood poles were replaced would reduce the unnecessary expense increases associated with corrections and contractor costs recorded to Sub-Account 583.120.

recorded expenses as SCE "began performing intrusive inspections on a grid basis".[466] SCE states that its forecast is based on its estimated cost-per-pole and the average number of distribution wood pole intrusive inspections it plans on performing between 2012 and 2014 as well as an anticipated cost for its intrusive contracts.[467]

Based on recent history, SCE's proposed intrusive wood pole inspections of 130,427 per year, for the next three years, during the rate case cycle appears to be unrealistic. As demonstrated in SCE's TY 2009 GRC for its intrusive wood pole inspections, SCE's intrusive inspections are the highest at the beginning of the cycle for its intrusive inspections, and then decrease in the following years.[468] Although SCE claims that its contractor costs are increasing, with a decrease in the number of actual intrusive inspections performed there should be a corresponding decrease in costs. SCE combined its actual number of poles intrusively inspected (physical drilling of holes in a pole) and its number of corrections together in its testimony which gives the appearance that more actual wood pole intrusive inspections are being performed.[469]

The five year average (2005-2009) of SCE's intrusive inspections/corrections performed is 77,327.[470] The number of SCE's intrusive wood pole inspections performed fluctuates each year and DRA's use of a five year average captures this fluctuation. SCE's test year forecast of $5.533 million ($16.559 million over three years) is more than is necessary to address its intrusive wood pole inspection activities. DRA notes that SCE made a similar argument in its TY 2009 GRC and requested an additional $5.338 million over its 2006 recorded expenses for intrusive wood pole inspections of $3.638 million. SCE was authorized an additional

---

[466] Ex. SCE-3, Vol. 4, Part 2, Chapters I-II, page 80. Recorded wood pole corrections are also included in this increase in expenses recorded in 2009 for Sub-Account 583.120.

[467] SCE made a similar argument in its TY 2009 GRC regarding increasing contract costs. SCE's recorded adjusted 2009 expenses of $5.990 million for intrusive wood pole inspections, which includes expenses incurred for its contractors, demonstrates that SCE's estimate for its contract costs were overstated.

[468] In SCE's Figure II-38, SCE shows that it performed 151,998 Inspections/Corrections for 2009 and in SCE's response to DRA-SCE-065-TLG question 5-a, SCE shows that it performed 132,104 Distribution Intrusive inspections as of December 2010. SCE's forecast for 2010 shown in Figure II-38 for Inspections/Corrections is 147,304 (Ex. SCE-03, Volume 4, Part 2, Chapters I-II, page 79).

[469] DRA has concerns regarding the high number of wood pole corrections SCE is recording compared to actual intrusive wood pole inspections performed. This unnecessarily increases costs and burdens ratepayers. SCE's Figure II-38 in Ex. SCE-03, Volume 4, Part 2, Chapters I-II, page 79.

[470] Ex. SCE-3, Vol. 4, Part 2, Chapters I-II, page 79.

$4.175 million for a total of approximately $7.813 million[471] to address its intrusive wood pole inspections and its associated contract costs.[472] SCE's 2009 recorded adjusted expenses for its intrusive wood pole inspections is $5.990 million. SCE has embedded funding in its historical expenses[473] to address its activities associated with its intrusive wood pole inspects and no additional funding is required over DRA's estimate of $3.939 million.

584.120 – Underground Detail Inspections

SCE forecast $1.687 million for Sub-Account 584.120 (Labor of $1.306 million and Non-Labor of $0.381 million) for its Underground Detail Inspections expenses.[474] SCE's forecast of $1.687 is an increase of $0.213 million or 14.45% over 2009 recorded adjusted expenses of $1.474 million. DRA utilized SCE's last recorded year as a basis for its forecast of $1.474 million for SCE's Sub-Account 584.120. DRA's estimate is $0.213 million less than SCE's forecast.

SCE's expenses declined each year for the last five years (2005-2009) from $3.081 million in 2005 to $1.474 million in 2009. The decline in expenses is "due primarily to the transition to DIMP [Distribution Inspection & Maintenance Program], and the utilization of a new field tool that easily records the time and cost associated with repairs performed during the inspection".[475] Based on DRA's understanding of SCE's DIMP program, SCE's costs associated with its maintenance activities should continue to decline in the test year or at a minimum remain at its 2009 expense levels.[476]

---

[471] The $7.813 million DRA calculated has not been adjusted to 2009 constant dollars.

[472] D.09.03-025 page 83 and 84.

[473] In SCE's TY 2009 GRC, SCE recorded its Intrusive Wood Pole Inspections and its Overhead Detail Inspections in Sub-Account 583.400. In its TY 2012 GRC, SCE records these two activities to Sub-Account 583.120. SCE provided information on its 2009 authorized funding for Sub-Account 583.400 for Wood Pole Intrusive Inspections and Overhead Detail Inspections of $16.150 million (in 2009 constant dollars) and provided its 2009 recorded expenses for these activities for Sub-Account 583.120 of $10.098 million (DRA-SCE-065-TLG question 1-a).

[474] Ex. SCE-3, Vol. 4, Part 2, Chapters I-II, page 73.

[475] Ex. SCE-3, Vol. 4, Part 2, Chapters I-II, page 73.

[476] During SCE's TY 2009 GRC, DRA discovered that under SCE's Distribution Inspection & Maintenance Program (DIMP), SCE would complete more maintenance, but it would lead to lower program/maintenance costs (i.e. less employee time needed to identify and classify maintenance programs, reduce the need to allocate resources to items that posed little or no safety or reliability risk, less crew travel time, less area set up, reduce the time needed to discuss work to be done, etc.) due to all work being completed on the pole/structure at the time of scheduled routine maintenance instead of

SCE's request for an additional $0.213 million over 2009 expenses is not justified. SCE states that its 2009 recorded adjusted expenses "reflects an ongoing Underground Detail Inspection program under DIMP. Although SCE claims "[w]e expect to continue to perform the major activities that recorded to this account in 2009",[477] SCE is requesting additional funding for those embedded costs to perform those same "major activities". It would be inappropriate to require increased ratepayer funding for activities that already have costs embedded in SCE's 2009 recorded expenses and no additional funding is required over its 2009 recorded adjusted expenses of $1.474 million.[478]

593.120 – Distribution Preventive Maintenance

SCE forecast $93.139 million for Sub-Account 593.120 (Labor of $18.929 million and Non-Labor of $74.210 million) for its Distribution Preventive Maintenance expenses.[479] SCE's forecast of $93.139 million is an increase of $11.105 million or 13.54% over 2009 recorded adjusted expenses of $82.034 million. SCE's Sub-Account 593.120 includes the following line items: Vegetation Management, Preventive Maintenance, Visalia Pole Yard Remediation, and Graffiti Removal. DRA utilized SCE's last recorded year as a basis for its forecast of $85.477 million for SCE's Sub-Account 593.120. DRA's estimate is $7.662 million less than SCE's forecast.

SCE's expenses for the four line items recorded in Sub-Account 593.120 have fluctuated during the five year period (2005-2009). DRA analyzed the recorded adjusted expenses and the forecast estimates for each individual line item to calculate its test year estimates for Sub-Account 593.120. DRA takes issue with SCE's line items for Vegetation Management of $52.934 million and Preventive Maintenance of $39.712 million.

DRA utilized SCE's last recorded year, the highest for the five year period (2005-2009) as a basis for its forecast. DRA recommends that SCE's expenses incurred for its Vegetation Management activities, including costs associated with its High Fire Hazard areas, receive

---

returning at a later time to complete work.

[477] Ex. SCE-3, Vol. 4, Part 2, Chapters I-II, page 74.

[478] DRA notes that SCE was authorized approximately $4.153 million (2009 dollars) in its TY 2009 GRC to address its Underground Line Operations activities that were recorded in Sub-Account 584.400. SCE's TY 2012 GRC utilizes Sub-Account 584.120. SCE's 2009 recorded adjusted expenses for Sub-Account 584.120 is $1.474 million (SCE-065-TLG question 1-b).

[479] Ex. SCE-3, Vol. 4, Part 2, Chapters I-II, page 88.

one-way balancing account treatment in the test year. Pacific Gas and Electric Company and San Diego Gas & Electric Company currently receive one-way balancing account treatment for costs associated with Tree Trimming and Vegetation Management activities.[480]

SCE's request for an incremental increase of $10.1 million ($30.300 million over the three year rate case cycle)[481] is not justified.[482] SCE's recorded adjusted expenses fluctuated between 2005 and 2008 with an average for the four year period (2005-2008) of $37.626 million. In 2009, SCE's expenses increased by $4.729 million over 2008 expenses.

SCE proposes to include the incremental costs of $10.1 million in its 2012 test year to address on-going cost-of-service activities associated with the high fire hazard area rule change.[483] DRA's test year estimate of $47.274 million includes additional funding of $4.612 million for SCE's High Fire Area Vegetation Management expenses. DRA calculated its estimate of $4.612 million for SCE's on-going costs to maintain this program[484] based on its

---

[480] Regarding San Diego Gas & Electric Company's one-way balancing account treatment for its Tree Trimming activities recorded to FERC Account 593.1 see D.08-07-046, Appendix 1, page 7. In PG&E's 2011 GRC (A.09-12-020) it requested continuation of its Vegetation Management one-way balancing account.

[481] SCE's recorded adjusted 2009 expenses for its Vegetation Management expenses recorded to Sub-Account 593.120 is $42.834 million. SCE's Figure II-39 on page 81 shows SCE's 2009 recorded adjusted expenses of $43.826 million, which includes $0.992 million recorded for its High Fire Area Vegetation Management expenses which is supposed to be currently tracked and recorded in its Fire Hazard Prevention Memorandum Account (FHPMA) until December 2011. SCE also included $172,000 in its 2009 recorded adjusted labor expenses for four Arborist positions relating to the High Fire activities that should be tracked and recorded in SCE's FHPMA account and was part of SCE's estimate for its projected costs for this program. DRA removed the $172,000 from SCE's 2009 recorded adjusted expenses because the costs were supposed to be tracked and recorded in the FHPMA.

[482] D.09-08-029 addressed measures to reduce fire hazard in California before the 2009 fall fire season. The decision adopted statewide measures to be initiated before the 2009 fall fire season starts. The decision found that cost-of-service regulated utilities are entitled to recover reasonable costs prudently incurred in compliance with D.09-08-029. In Phase 2 of R.08-11-005, the Commission would determine the proceeding for recovery of these costs. SCE was to establish the Fire Hazard Prevention Memorandum Account (FHPMA) to track and record costs related to fire safety and to implement fire prevention corrective action measures in extreme and very high fire threat areas. SCE was required to record the difference between all fire hazard prevention costs related to activities necessary to implement the requirements of D.09-08-029 and the amounts previously authorized in its 2009 GRC (D.09-03-025) in the FHPMA (Advice Letter 2387-E (U 338-E).

[483] Ex. SCE-03, Volume 4, Part 2, Chapters I-II, page 82.

[484] In SCE's projected costs of $24.742 million (later revised to $21.808 million) that it provided to CPSD (OIR R.08-11-005) for costs that were to be tracked and recorded in its FHPMA, SCE included eight line items in the $24.742 million projection that were related to costs that were to be incurred through 2011. SCE also included an annual cost estimate for expenses that were to begin in 2012, and that total was $10.073 million. The amount of $10.073 million appears to be the amount of SCE's incremental request of $10.1 million for the TY 2012 GRC for Sub-Account 593.120. SCE stated "SCE's costs estimates

review and analysis of SCE's preliminary year-to-date high fire vegetation management work completed in 2010 to comply with R.08-11-005.[485] Based on SCE's testimony, it appears that SCE has embedded funding in its 2009 recorded adjusted expenses related to its High Fire Area Vegetation Management program. DRA has concerns that SCE may be double counting expenses by including 2009 costs directly associated with the maintenance of its high fire hazard area in Sub-Account 593.120 and also including those same costs that are supposed to be tracked and recorded (to be recovered later) in its High Fire Area Vegetation Management program established Fire Hazard Prevention Memorandum Account (FHPMA).

SCE states "From 2008-2009 labor costs increased by $172,000 due primarily to hiring four additional personnel late in 2009 to address tree trimming related issues specific to High Fire area. These four additional personnel are vegetation arborists[486] hired as a result of the Commission's change in the vegetation clearance requirements in High Fire areas, which became effective August 20, 2009".[487] SCE states further that its non-labor costs for "the period 2008 to 2009 costs increased by $4.558 million due to an increase in tree removals and mid-cycle trims, and the inclusion of costs for vegetation management in high fire hazard areas".[488] SCE did not provide information on the specific cause of the increase in "tree removals and mid-cycle trims" or a detailed breakdown of the increase in costs of $4.558 million for review and analysis to determine if the one-time costs, for the increase in tree removals were part of the high fire related

---

were developed very quickly based upon a field review of approximately 1,000 trees in one area, the result of which were projected across six affected counties in our service territory. Given the time constraints in Phase I of this proceeding SCE cannot perform a more exhaustive study regarding the impacts of this new rule to its enactment, as would be necessary to develop better cost estimates" (R.08-11-005_CPUC-SCE-VM Cost Recovery Plan).

[485] SCE provided its 2010 preliminary year to date high fire management work completed in its response to DRA-SCE-065-TLG question 8-b. DRA removed certain costs from its estimate due to the costs being embedded in SCE's historical expenses (i.e. Patrols) or were specific one-time costs that should not be included in the test year estimate (tree removals). DRA removed costs incurred for Patrols of $1.497 million and costs for removals of Overhangs, Hazard trees, and Palm trees totaling $4.895 million.

[486] In SCE's projected costs of $24.742 million (later revised to $21.808 million) that it provided to CPSD (OIR R.08-11-005) for costs that were to be tracked and recorded in its FHPMA, SCE included line item estimates for various costs that it claimed were going to be incurred to comply with the requirements, and SCE included costs for four full time Arborist employees and the costs were to be included in the FHPMA to establish and maintain 48" Vegetation- to-Line Clearance.

[487] Ex. SCE-3, Vol. 4, Part 2, Chapters I-II, page 82.

[488] Ex. SCE-3, Vol. 4, Part 2, Chapters I-II, page 82.

expenses that should have been recorded in its FHPMA.[489] SCE did not provide a detailed breakdown of costs or a discussion on the specific expenses it incurred in 2009 to address the high fire hazard areas in order to determine if all associated high fire hazard costs were properly recorded in its FHPMA and not in Sub-Account 593.120 in 2009. DRA requested additional information on SCE's test year forecast for Sub-Account 593.120.

DRA asked:[490]

> SCE states that the "Commission expressly provided that "each cost of service regulated utility is entitled to recover reasonable costs prudently incurred to comply with the changes to the Commission's rules…" Provide a detailed and itemized listing that shows all costs "incurred to comply with the changes to the Commission's rules" including copies of invoices, contracts, etc.

SCE's response:

With approximately two weeks worth of invoices still outstanding the preliminary YTD high fire vegetation management work completed to comply with CPUC (R.08-11-005) is as follows:

[489] Since SCE is supposed to be tracking and recording costs incurred for activities associated with the high fire hazard area in the FHPMA through 2011, to be recovered later, if SCE included any of those costs incurred in 2009 (its base year for the 2012 GRC) in its Sub-Account 593.120 and its FHPMA, SCE's ratepayers would be funding those high fire activities twice. It is inappropriate to charge ratepayers twice for the same activities. Regarding recovery of high fire hazard costs, SCE states "In the workshops and in its briefs in Phase 2, SCE requested that the balance accrued in the memorandum account be recovered annually in its ERRA recovery proceeding until 2012 at which time SCE would forecast the amounts necessary to comply with the rule changes in its 2012 General Rate Case as an on-going cost of service" (DRA-VERBAL-077 question 1).

[490] DRA-SCE-065-TLG question 8-b.

	($Millions)	Work Completed
Patrols[491]	$ 1.497	
Heavy Tops	$ 0.928	3,971 Trees
Remove Overhangs[492]	$ 1.783	3,402 Trees
Compliance Trims	$ 3.055	52,004 Trees
Remove Hazard Trees	$ 1.765	2,540 Trees
Remove Palm Trees	$ 1.347	3,784 Trees
Skin Palm Trees	$ 0.048	186 Trees
Perform clear ups	$ 0.581	
Total (preliminary)	$11.004	67,599

Please see the response to questions 8.c for more information and details regarding the development of SCE's cost forecast and the estimated costs to comply with the changes to the Commission's vegetation rules in R.08-11-005. Please see SCE's response to DRA master request MDR-05, question V.03 for copies of SCE's vegetation management contracts. Copies of all invoices are too voluminous to provide, but the detailed records can be made available for review in SCE's General Office in Rosemead. These numbers are preliminary, based on invoices to date, as SCE does not have recorded-adjusted expenses by sub-account for 2010. The FERC FORM 1 by FERC account (not sub-account) will be made available in the second quarter of 2011.

DRA asked:[493]

[491] The costs incurred for Patrols of $1.497 million should be removed from the calculation of SCE's test year estimate of $10.1 million due to the fact that SCE was authorized funding for Patrols in its 2009 GRC and theses costs are already embedded in historical expenses. Changes to GO 165 were adopted in D.09-08-029 for SCE's patrol inspections in rural areas by increasing those inspections to once per year in Extreme and Very High Threat Zones in counties as defined by California Dept. of Forestry and Fire Protection and Resource Assessment Program (FRAP) Fire Threat Map. SCE's Patrol Inspection program follows this practice and funding was authorized in its 2009 GRC therefore SCE is not to record expenses incurred for annual patrol inspections in rural areas unless the Commission makes changes and the FRAP Fire Threat Map is revised. Expenses incurred for joint pole activities will not be recorded unless the Commission changes GO 165.

[492] Note that expenses incurred in 2010 for Removal of Overhangs of $1.783 million, Hazard Trees of $1.765 million, and Palm Trees of $1.347 million are specific one-time costs and should not be included in the calculation of SCE's test year estimates to address on-going activities. Note that in SCE's projected costs that it provided to CPSD of $24.742 million, SCE removed costs incurred for tree removals from its estimate of annual costs.

[493] DRA-SCE-065-TLG question 8-h.

> SCE's non-labor expenses increased by $4.558 million "due to an increase in tree removals and mid-cycle trims, and the inclusion of costs for vegetation management in high fire hazard areas". Provide the documentation that explains the increase in more detail regarding the specific expenses for the "tree removals and mid-cycle trims, and the inclusion of costs for vegetation management in high fire hazard areas.

SCE's response:

> In 2008 SCE recorded 12,857 mid-cycle trims, compared to 15,875 mid-cycle trims in 2009. Details regarding tree removals were provided in response to DRA master data request MDR-05 question V.01, part c. The inclusion of costs incurred in 2009 for vegetation management in high fire areas resulting from R.08-11-005 is shown in the attachment provided in response to questions 8.f under the line items "Inspections/Line clearing (OIR)" and Trim & Remove Trees – 48 Inch Rule".[494]

SCE's responses are incomplete and do not support or justify additional funding of the $10.1 million it claims is needed to address on-going maintenance activities in its high fire hazard area. SCE also has embedded costs that it can utilize in the test year for on-going activities. DRA's estimate of $47.274 million, including additional funding of $4.612 million, is a reasonable test year estimate for SCE to address its Vegetation Management activities.

DRA forecast $37.710 million for SCE's O&M Preventive Maintenance expenses utilizing SCE's 2009 recorded adjusted expenses as a basis. DRA's estimate is $2.002 million less than SCE's estimate. SCE developed its test year forecast of $39.712 million for its O&M Preventive Maintenance expenses utilizing a budget-based forecast of maintenance activities.[495]

SCE states "The last recorded year (2009) expense provide a reasonable starting point for estimating future level of expenses for this sub-account, because the last recorded year reflects the first full year under the new DIMP program, and we expect to continue to perform the major activities that recorded to this account in 2009".[496] DRA agrees that the use of SCE's 2009

---

[494] In SCE's response SCE shows two line items totaling $0.992 million for 2009 which is supposed to be associated with the High Fire Area Vegetation Management. The specific activity associated with the recorded expenses is not identified, and there is no discussion on these costs for review and analysis. SCE states "An itemized list of all transactions is too voluminous to provide, but the detailed records are available for review in SCE's General Office in Rosemead" (DRA-SCE-065-TLG questions 8-f).

[495] DRA-SCE-065-TLG question 7-a.

[496] Ex. SCE-3, Vol. 4, Part 2, Chapters I-II, page 85.

recorded adjusted expenses as a basis for SCE's test year estimate is reasonable especially since it is the first full year of SCE's DIMP program, and is a more reasonable method when compared to SCE's budged-based method.

SCE's O&M Preventive Maintenance labor expenses increased by $7.286 million between 2005 and 2009, from $8.542 million in 2005 to $15.828 million in 2009 with an average for the period of $11.183 million. SCE's non-labor expenses declined by $13.849 million between 2006 and 2008 from $28.024 million in 2006 to $14.175 million in 2008 and then increased by $7.707 million in 2009. The average for the five year period (2005-2009) for SCE's non-labor expenses is $22.593 million. The increases in labor expenses and the decrease in non-labor expenses were due to SCE's transition to its DIMP program, which increased its maintenance activities and reduced the work performed by contractors.[497]

SCE's 2009 recorded adjusted expenses are a reasonable test year estimate. SCE also has embedded funding in its historical expenses that it can utilize for its routine and on-going O&M maintenance activities. It is inappropriate to require increased ratepayer funding for activities that already have costs embedded in SCE's 2009 recorded expenses, and no additional funding is required over its 2009 recorded adjusted expenses of $37.710 million.

594.120 – Distribution Apparatus

SCE forecast $4.031 million for Sub-Account 594.120 (Labor of $2.932 million and Non-Labor of $1.099 million) for its Distribution Apparatus expenses.[498] SCE's forecast of $4.031 million is an increase of $0.539 million or 15.44% over 2009 recorded adjusted expenses of $3.492 million. DRA utilized SCE's last recorded year as a basis for its forecast of $3.492 million for SCE's Sub-Account 594.120.

SCE's labor expenses fluctuated during the five year period (2005-2009) due to increased underground apparatus repairs and inspections, and decreases in compliance inspections.[499] SCE's recorded labor expenses averaged $2.241 million for the five year period and averaged $2.404 million for the three year period (2007-2009). SCE's 2009 recorded adjusted expenses were $2.542 million. SCE's non-labor expenses declined by $1.137 million between 2006 and

[497] Ex. SCE-3, Vol. 4, Part 2, Chapters I-II, page 84 through 85.

[498] Ex. SCE-3, Vol. 4, Part 2, Chapters I-II, page 76.

[499] Ex. SCE-3, Vol. 4, Part 2, Chapters I-II, page 76.

2008 from $2.064 million in 2006 to $0.927 million in 2008 and remained relatively stable between 2008 and 2009 with recorded non-labor expenses of $0.950 million.

SCE's request for an additional $0.539 million over 2009 recorded adjusted expenses for Sub-Account 594.120 is unnecessary for SCE to address its work activities in the 2012 test year. SCE states that its "apparatus inspection and maintenance program has remained the same from 2005-2009", but that its "cost-per-unit has fluctuated over this period, thus we used the five year average unit cost to develop forecasts".[500] DRA assumes that SCE's apparatus inspection and maintenance program, which "remained the same from 2005-2009", will continue to remain the same in the test year. It is inappropriate to require increased ratepayer funding for activities that already have costs embedded in SCE's 2009 recorded expenses and no additional funding is needed over its 2009 recorded adjusted expenses of $3.492 million.[501]

Capital Expenditures

According to SCE, Capital Maintenance programs refer to the inspection driven replacement of major pieces of SCE's equipment, such as poles, transformers, switches, and underground structures. Inspection driven replacements are based on equipment condition or inspection findings. These conditions can be identified during G.O. 165 mandated inspections or during the normal course of business. SCE says it prioritizes maintenance work based on relative safety, and significance to reliability.[502]

5.8.1. Overview of SCE's Request

In this GRC, SCE seeks $208.8 million in 2010, $212.6 million in 2011, and $232 million in 2012.[503] DRA recommends $227.4 million in 2010, $149.6 million in 2011 and $149.8 million in 2012. SCE's historical capital expenditures went up in 2006 and 2009, but

---

[500] Ex. SCE-3, Vol. 4, Part 2, Chapters I-II, page 77.

[501] DRA notes that SCE was authorized approximately $5.130 million (2009 dollars) in its TY 2009 GRC to address its Distribution Apparatus activities that were recorded in Sub-Accounts 584.300, 593.100 and 594.100. In SCE's TY 2012 GRC it combined these three Sub-Accounts into Sub-Account 594.120. SCE's 2009 recorded adjusted expenses for Sub-Account 594.120 is $3.492 million (SCE-065-TLG question 1-a).

[502] Ex. SCE-3, Vol. 4, Part 01 & 02, p. 89, lines 1-11.

[503] Ex. DRA-7, p. 23, Table 7-5. The numbers in DRA's testimony are in millions of 2009 dollars. SCE's Direct Testimony included some data in constant 2009 dollars, and some in both constant 2009 and nominal dollars. DRA's testimony uses 2009 dollars.

down in 2007 and 2008. The highest amount SCE spent was $274.7 million in 2006, and the lowest amount was $180.7 million in 2008.

5.8.2. Capital Preventive Maintenance

SCE says that Capital Preventative Maintenance includes the replacements of: (1) underground cables; (2) overhead conductors; (3) overhead transformers; (4) underground transformers; (5) transformer bank replacement program; and, (6) underground structure replacement programs.[504]

SCE's forecast is in three areas. Area 1 covers asset based preventative maintenance and includes overhead conductors, underground cable, overhead transformers, and underground transformers; Area 2 covers SCE's transformer bank replacement program; Area 3 includes SCE's underground structure replacement programs.

For the three areas of Capital Preventive Maintenance combined, SCE's 2011 forecast is $116.2 million and its TY 2012 forecast is $126.7 million in 2009 constant dollars.[505] DRA recommends $94.3 million for each of the years 2011 and 2012 in 2009 constant dollars.[506]

SCE generally projected out the number of replacement units for the years 2010-2014 and multiplied the replacement units by the 5-year average price to install each replacement unit. In its workpapers, SCE states that generally "Total preventative maintenance costs = Asset unit costs * Total assets * Asset replacement rate"[507] SCE's method is, thus, to calculate assets replaced based on SCE's total assets.

5.8.2.1. Asset Based Preventive Maintenance

DRA reviewed the supporting documentation from SCE regarding its calculations of asset based preventive maintenance. DRA then calculated the correlation co-efficient between the total assets and the failure rate, the failure rate and the replacement units, and the total assets and the replacement units using the seven years of data SCE provided.

---

[504] Ex. SCE-3, Vol. 04, Part 01 & 02, p. 90, lines 4-7.

[505] Ex. DRA-7, p. 23, Table 7-5.

[506] Ex. DRA-7, p. 31, Table 7-10.

[507] Ex. DRA-7, p. 24 citing SCE Workpaper Transmission & Distribution, Inspection & Maintenance, Exhibit SCE-03, Vol. 04, Part 02, Ch. II, page 197.

By DRA's calculations, the correlation co-efficient between total assets and replacements units for three of the four groups ranges from 0.4222467 to 0.8232861.[508] These rates are too low for any legitimate forecast. An acceptable correlation co-efficient should be above 0.95 and analysts prefer to see sample sizes that are greater than 30, SCE used a sample size no larger than 7.

Overhead conductor replacement units went down in 2007 and 2008, and up in 2006 and 2009. Underground cable replacement units went down in 2007, 2008 and 2009, and went up only in 2006. Overhead transformer replacement units went down in 2008, and went up 2006, 2007 and 2009. Overhead transformer replacement units did the same thing as overhead transformers; they went down in 2008 and up in 2006, 2007 and 2009.

SCE also uses the 5-year average unit cost to determine the cost of each replacement unit. The cost data which SCE uses is higher than SCE's replacement costs in 2008 and 2009. Actual costs have come down during the last two years. It should also be noted that SCE's method of determining unit replacement costs is not consistent. In determining the unit costs in the section on breakdown maintenance SCE used the 2009 unit cost, not the 5-year average unit cost.[509]

For underground cable, DRA recommends using the 2009 replacement units because the replacement units have been decreasing during the last four years. For overhead transformers and underground transformers, DRA used a three year average of units replaced. As can be seen in the 2007-2009 data, the units appear to be leveling out with a dip in 2008. DRA used 2009 unit costs since costs have been coming down.

5.8.2.2. Transformer Bank Replacement

SCE used two other elements in determining its total Capital Preventative Maintenance capitalized expenditures: capital expenditures for its transformer banks replacement program, and capital expenditures for its underground structure replacement program. SCE forecasts zero ratepayer funding in 2011 and 2012 in its transformer banks replacement program. DRA agrees; these capital expenditures are in the historic 2010 costs.[510]

---

[508] Ex. DRA-7, p. 26, Table 7-8.

[509] Ex. DRA-7, p. 28 citing SCE Workpapers Transmission & Distribution, Distribution Construction & Maintenance, SCE-3, Vol. 4, Part 6, Ch. II, pages 45-46

[510] Ex. DRA-7, p. 29.

5.8.2.3. Underground Structures

SCE projects large increases in its underground structure replacement program. Under the Distribution Inspection and Maintenance Program, SCE began using a new process for identifying, tracking, and evaluating underground structures. According to SCE, beginning in 2009, "…when concrete structures are identified to be significantly deteriorated during the underground detail inspection, they are scheduled for re-inspection by a licensed civil engineer who determines whether the structure can be repaired or must be replaced."[511] SCE's historic costs range from $90,000 in 2007 to $2.8 million in 2009. SCE seeks ratepayer funding for up to $13.9 million in 2012 in increased capitalized expenditures for this program.[512] DRA recommends the Commission authorize $5.6 million in 2011 and again in TY 2012 for this program.[513]

SCE says it has identified a total number of 43 underground concrete structures that need replacement and that it expects to replace 217 underground structures from 2010 to 2014.[514] In 2010 SCE projected capital expense for underground structure replacements of $8.9 million; it actually spent $5.4 million.

In Rebuttal, SCE says that it spent less than it forecast in 2010 because SCE experienced longer lead times and more complicated design work than anticipated, particularly for work in urban areas.[515] DRA remains concerned that, for the period 2010 – 2012, SCE is asking for funding that is six and a half times more than SCE's expenditures over the past five years for a brand new program with no real track record. In its next GRC, SCE will, or should, have developed a historical record. For this GRC, however, DRA recommends that the Commission allow ratepayer funding in the amount of $5.6 million per year for SCE to replace the 20 underground vaults in 2011 and 2012 that SCE estimates that it will find needing replacement in 2012.[516]

---

[511] Ex. SCE-3, Vol. 4, Part 1 & 2, p. 92, lines 9-13.

[512] Ex. DRA-7, p. 24, Table 7-6, SCE's TY 2012 forecast is shown in 2009 dollars.

[513] Ex. DRA-7, p. 31.

[514] Ex. SCE-3, Vol. 4, Part 1 &2, p. 92, lines 14-20.

[515] Ex. SCE-18, Vol. 4, Part 1 & 2, p. 36.

[516] Ex. DRA-7, p. 31 citing SCE Workpapers Transmission & Distribution, Distribution Construction & Maintenance, SCE-03, Volume 4, Part 6, Ch. II, page 206

5.8.3. Wood Pole Replacement

SCE says it plans to spend $486.156 million over the 2010 – 2014 period on distribution wood pole replacements.[517] Of that, SCE forecasts $63.2 million for 2010, $97.8 million for 2011 and $109.7 million for wood pole replacements in the years 2010, 2011 and 2012.[518] DRA recommends $89.8 million in 2010, $57.1 million in 2011 and $57.1 million in 2012.[519]

SCE says it manages approximately 1.5 million wood poles in its system. According to SCE, it routinely assesses its poles through intrusive inspections and detailed inspections, as required by G. O. 165. Intrusive inspections involve drilling into each pole's interior to measure the extent of any internal decay. Poles with deterioration are identified for repair or replacement. Pole repairs and replacements are prioritized for repair or replacement based on safety significance and to meet the strength requirement of G. O. 95.[520] SCE says that, "[g]oing forward, beginning in 2012, SCE expects to perform approximately 130,000 grid based intrusive pole inspections per year through the rate case cycle."[521] This is approximately double the number of inspections SCE has been doing over the last 5 years.[522]

Between 1998 and 2007, SCE performed intrusive pole inspections in accordance with the first cycle of GO 165. This cycle required SCE to perform an intrusive pole inspection on all wood transmission and distribution poles over a ten year cycle. In the second cycle, 2008-2017, all wood distribution and transmission poles which are 25 years old (installed before 1993) are required to have an intrusive pole inspection performed over the next 20 years, and all poles installed between 1993 and 2002, will need to have an intrusive pole inspection during the second cycle which will end in 2017.[523]

During the first cycle, SCE experienced a failure rate of 7.7% (for every 1,000 poles inspected, SCE needed to replace 77 poles).[524] SCE's experience during the second cycle is that

---

[517] Ex. SCE-3, Vol. 4, Part 1 & 2, p. 94, Figure II-45, 2009 Constant $.

[518] Id.

[519] Ex. DRA-7, p. 23, Table 7-5, 2009 Dollars.

[520] Ex. SCE-3, Vol. 4, Part 1 & 2, p. 93, lines 1-8.

[521] Ex. SCE-3, Vol. 04, Part 1 & 2, p. 78, lines 7-8.

[522] Ex. DRA-7, p. 32.

[523] General Order 165.

[524] Ex. DRA-7, p. 33 citing Response to DRA-SCE-198-MKB, Q. 2.

it is failing only 3.3% of the poles.[525] This decreased failure rate would decrease SCE's costs by about half if SCE used the same number of intrusive pole inspections.

Besides the poles being replaced because they failed the intrusive inspection, SCE says poles will also be identified for replacement for reasons that "...can include those identified by local Districts as being unsuitable for climbing, insufficiently strong to support new equipment or poles initially identified for repair but later concluded to be too deteriorated."[526]

DRA compared SCE's forecast calculations to SCE's G.O. 165 intrusive inspection requirements. SCE's projections do not follow the intrusive inspection schedule set forth in G.O. 165, nor do they match what SCE has been doing over the last 5 years. SCE's 2010-2014 projection would result in 20,658 intrusive inspection replacements as opposed to SCE's five-year average of 12,760 (2,552 * 5) replacements, with, of course, an attendant increase in costs.[527]

DRA prepared its own estimate of the 2011 & 2012 expenditures necessary to replace distribution wood poles annually. For capital expenditures, DRA used a 5-year average intrusive inspection number of 77,327 multiplied by SCE's second cycle failure rate 3.3%, or a 5-year average number of annual distribution wood pole replacements of 2,552. DRA then added SCE's 2010 (1) repaired pole inspections replacements of 249; (2) district distribution wood pole replacement requests of 734; and (3) estimated other distribution wood pole replacement requests of 1,165. DRA then multiplied the total distribution wood replacements (4,700) by SCE's 2009 average cost of installing a transmission wood pole ($12.15) which results in distribution wood pole replacement costs in 2011 and 2012 of $57.1 million annually.[528]

DRA's capital expenditure forecasts for wood pole replacements are consistent with SCE's 5-year average of intrusive inspections, and provide SCE funding beyond what it needs to perform the number of intrusive inspections required by G.O. 165, which is 65,650 a year.[529]

---

[525] Ex. DRA-7, p. 33 citing Response to DRA-SCE-198-MKB, Q. 3.

[526] Ex. SCE-3, Vol. 4, Part 01 & 02, Ch. I-II, pages 93-94, lines 18-2. In its Workpapers, SCE refers to Workpapers Transmission & Distribution, Inspection & Maintenance SCE-3, Vol. 4, Part 2, Ch. II, page 219.

[527] Ex. DRA-7, p. 33.

[528] Ex. DRA-7, p. 34.

[529] Ex. DRA-7, p. 34.

5.8.4. Joint Pole Credits

SCE forecasts Joint Pole Credits of ($11.2) million in 2010, ($11.4) million in 2011 and ($14.6) million in 2012.[530] DRA recommends Joint Pole Credits of ($8.3) million for 2011 and ($8.1) million for 2012.[531]

When SCE installs a new or replacement distribution or transmission pole, it recovers some of the cost from the other utilities that also use the pole. These other utilities have typically purchased partial ownership in the pole. The forecast reflects the payments SCE expects to receive from other parties.[532]

The primary difference between SCE's and DRA's Joint Pole Credits projections is DRA's use of a five-year average intrusive pole inspection for the distribution and transmission pole replacements versus SCE's forecast, which nearly doubles the intrusive pole inspections SCE has actually done over the past five years.[533]

5.8.5. Wood Pole Disposal

SCE seeks approximately $1.7 million in 2010, $1.6 million in 2011, and $1.8 million for Wood Pole Disposal costs.[534] DRA recommends$1.9 million for 2010, $0.5 million for 2011 and $0.5 million for 2012.

When wood poles are removed from service, SCE must take special measures in disposing of them because all of the poles have been treated with chemical preservatives and are considered hazardous waste.[535]

SCE's says its forecast is tied primarily to the number of distribution poles being replaced. The difference between SCE's forecast and DRA's for Wood Pole Replacements is discussed above and accounts for the difference in SCE's and DRA's Wood Pole Disposal forecasts.

---

[530] Ex. SCE-3, Vol. 4, Part 1 & 2, p. 95, Table II-28, 2009 Constant $.

[531] Ex. DRA-7, p. 35.

[532] Ex. SCE-3, Vol. 4, Part 1 & 2, p. 96, lines 6-10.

[533] Ex. DRA-7, p. 35.

[534] Ex. SCE-3, Vol. 4, Part 1 & 2, p. 99, Figure II-48, 2009 Constant $.

[535] Ex. SCE-3, Vol. 4, Part 1 & 2, p. 98, lines 1-4.

5.8.6. Removal of Idle Facilities

SCE says it plans to spend $4.0 million per year in 2009 constant dollars over the 2010-2014 period for the removal of idle facilities.[536] DRA recommends the Commission adopt $9.0 million for 2010, $1.5 million for 2011, and $1.5 million for 2012.[537]

When facilities are no longer used and useful, SCE removes those facilities from its rate base.[538] SCE modified its request in a data response to DRA. SCE's revised 2009 constant dollar amount for Removal of Idle Facilities projections is $4.0 million for 2010-2014.

SCE is seeking $12 million in Removal of Idle Facilities capital expenditures over the period 2010-2012. DRA is recommending that SCE's requested amount be allowed. DRA accepts SCE's actual 2010 capital expenditures. Since the recorded 2010 Removal of Idle Facilities expenditures are much higher than those projected by SCE, DRA has allocated the remaining balance split between 2011 & 2012. This will still allow SCE to perform the same work planned in this area, since SCE will recover what it had requested over the 2010-2012 period.[539]

5.9. T&D - Distribution Planning and Field Accounting Operations and Maintence Expenses - 588.130

SCE forecast $5.699 million for its Distribution Planning and Field Accounting expenses.[540] SCE developed its forecast by utilizing its 2009 recorded adjusted expenses for Sub-Accounts 588.130 and 589.130 plus incremental expenses for proposed projects and work activities. The corresponding DRA estimate for SCE's Distribution Planning and Field Accounting expenses is $4.080 million, which is $1.619 million less than SCE's forecast.

588.130 – Central Distribution Design – Mapping, Joint Pole, and Field Accounting

SCE forecast $5.095 million for Sub-Account 588.130 (Labor of $4.683 million and Non-Labor of $0.412 million) for its Central Distribution Design – Mapping, Joint Pole, and

---

[536] Ex. DRA-7, p. 37, citing Response to DRA-SCE-104-MKB Q. 5, Attachment 8 of 9.

[537] Ex. DRA-7, p. 23, Table 7-5.

[538] Ex. SCE-3, Vol. 04, Part 01 & 02, Ch. I-II, pages 99-100, lines 1-1

[539] SCE requested recovery of $12 million ($4 million + $4 million + $4 million) while DRA recommends $12 million ($9 million + $1.5 million + $1.5 million).

[540] Ex. SCE-03, Volume 4, Part 3, Chapters I-II, page 9.

Field Accounting expenses.[541] SCE's Sub-Account 588.130 includes test year forecasts for the following line items: Field Accounting, Facilities Inventory Mapping, Joint Pole Activities, and Miscellaneous Expenses (employee recognition awards). DRA utilized SCE's last recorded year, a two and five year average as a basis for its forecast of $3.476 million for SCE's Sub-Account 588.130.

SCE's expenses for the four line items recorded in Sub-Account 588.130 have fluctuated during the five year period (2005-2009). DRA takes issue with the following line items discussed below that are included in the forecast for Sub-Account 588.130.

DRA forecast $72,528 for SCE's Field Accounting expenses utilizing SCE's allocation of 4.8% (discussed later in this paragraph) and applying that to SCE's two year average (2008 and 2009) of recorded adjusted expenses. DRA's estimate is $880,472 less than SCE's estimate. SCE states "In 2012 the percentage of total Field Accounting expenses allocated to Field Accounting O&M will be reduced to 4.8%, based on a more recent analysis of capital versus O&M activity. This percentage reduction reduces our forecast for O&M expenses from $1.651 million to $953,000".[542] DRA notes that $953,000 is not 4.8% of $1.651 million. DRA calculated 4.8% of $1.651 million to be $79,248 ($1.651 million multiplied by 4.8% equals $79,248). DRA utilized a two year average (2008-2009) to calculate its test year estimate due to the fact that "2008 was the first full year of the accounting change to an allocated cost/O&M split for Field Accounting expenses".[543]

DRA forecast $2.675 million for SCE's Joint Pole expenses utilizing SCE's 2009 recorded adjusted expenses. DRA's estimate is $0.500 million less than SCE's estimate. SCE's Joint Pole labor expenses increased slightly between 2005 and 2009 averaging $2.325 million for the five year period (2005-2009) while its non-labor expenses decreased each year during the period from $0.417 in 2005 to $0.063 million in 2009. SCE increased its staffing level between 2005 and 2009 by eight employees to address its work activities associated with joint pole

---

[541] Ex. SCE-3, Vol. 4, Part 3, Chapters I-II, page 48.

[542] Ex. SCE-3, Vol. 4, Part 3, Chapters I-II, page 42.

[543] Ex. SCE-3, Vol. 4, Part 3, Chapters I-II, page 41. DRA calculated its test year estimate utilizing SCE's two year average (2008-2009) for recorded adjusted expenses of $1.511 million and applied the 4.8% to equal $72,528.

requests.[544] SCE's incremental test year forecast of $0.500 million over 2009 recorded adjusted expenses was for hiring five additional employees over three years.

SCE was authorized an additional $0.438 million in its TY 2009 GRC to fund six additional positions in its Joint Pole Organization, however SCE's recorded adjusted 2009 expenses and its staffing level does not reflect this fact.[545] SCE should have embedded costs and expenses incurred for overtime in its historical expenses that it can utilize for additional staffing it claims it needs in the test year. SCE's 2009 recorded adjusted expenses are a reasonable test year estimate.

DRA forecast $0.063 million for SCE's Miscellaneous expenses utilizing a five year average of SCE's 2009 recorded adjusted expenses for minor furniture and equipment.[546] DRA's estimate is $0.239 million less than SCE's forecast. SCE's Miscellaneous expenses include costs for its minor furniture and equipment and employee recognition.[547] SCE's 2012 forecast of $0.302 million for its Miscellaneous expenses includes $0.239 million of employee recognition expenses which DRA removed from its test year estimate for ratemaking purposes.[548] DRA made a normalized adjustment to SCE's recorded adjusted historical expenses (2005-2009) of $0.239 million recorded in Sub-Account 588.130 for ratemaking purposes. DRA's adjustment was made to remove discretionary costs associated with SCE's employee recognition program Spot Bonuses and Awards to Celebrate Excellence Recognition Points (ACE), which are inappropriate to charge to ratepayers. SCE's employee recognition programs provide no clear or identifiable benefit to ratepayers and are not necessary to operate the utility business.

---

[544] SCE's response to DRA-SCE-086-TLG question 6-d.

[545] D.09-03-025 page 91.

[546] SCE provided its 2005-2009 recorded expenses incurred for minor furniture and equipment in its response to DRA-SCE-086-TLG question 7-e, and provided the five year average of these expenses of $63,000 in DRA-SCE-086-TLG question 7-f.

[547] Ex. SCE-3, Vol. 4, Part 3, Chapters I-II, page 45.

[548] SCE provided its 2012 forecast expenses for employee recognition expenses in its response to DRA-SCE-086-TLG question 7-c.

5.10. T&D - Grid Operations

Operations and Maintenance Expenses - 561.170, 562.170, 573.170, 582.170, 583.170, 588.170, 593.170, & 598.170.

SCE forecast $89.707 million for its Grid Operations expenses.[549] SCE developed its forecast by utilizing its 2009 recorded adjusted expenses for Sub-Accounts 560.170, 561.170, 562.170, 573.170, 582.170, 583.170, 585.170, 587.170, 588.170, 593.170, 596.170, and 598.170 plus incremental expenses for proposed projects and work activities. The corresponding DRA estimate for SCE's Grid Operations expenses is $71.972 million, which is $17.735 million less than SCE's forecast. DRA takes issue with SCE's test year forecasts for the Sub-Accounts that are discussed below.

561.170 – Grid Control Center Costs

SCE forecast $6.057 million for Sub-Account 561.170 (Labor of $4.860 million and Non-Labor of $1.197 million) for its Grid Control Center Costs. SCE's forecast of $6.057 million is an increase of $1.585 million or 35.44% over 2009 recorded expenses of $4.472 million. DRA utilized SCE's 2009 recorded adjusted expenses, the highest level of expenditures for the five year period, as a basis and forecast $4.472 million for Sub-Account 561.170.

SCE's requested increase is not justified when compared to historical levels. SCE states that it "will add employees to Grid Control Management" due to "continuously increasing work resulting from new and changing NERC reliability standards", and its "need to begin staffing the Alternate Grid Control Center".[550]

Based on the information SCE provided, it appears that SCE never had permanent staffing at its Alternate Grid Control Center.[551] Further, SCE did not provide any documentation that demonstrated specific and identifiable problems which prevented it from successfully managing all associated work activities relating to its Alternate Grid Control Center during 2005 through 2009. SCE's proposal to hire ten additional employees during the three year rate case cycle to address work recorded to Sub-Account 561.170 is suspect, since SCE has only hired

---

[549] Ex. SCE-3, Vol. 4, Part 5, Chapters I-II, Page 13.

[550] Ex. SCE-3, Vol. 4, Part 5, Chapters I-II, page 17.

[551] DRA notes that in SCE's TY 2009 GRC, SCE's TDBU requested and was authorized substantial funding in various Sub-Accounts to address new hires to account for employee retirement and work related projects, yet SCE did not staff its Alternate Grid Control Center.

four employees to address these work activities between 2005-2009. SCE states that it "increased the number of Power System Operators and Power System Planners from 25 in 2005 to 29 in 2009".[552]

DRA discovered in a meeting on February 10, 2011 between DRA and SCE that SCE has been incurring costs related to "new and changing NERC reliability standards" during the historical period, and that although SCE has been incurring expenses it has not separately tracked those embedded costs in TDBU.[553] Although SCE states that it has "continuously increasing work resulting from new and changing NERC reliability standards", SCE's recorded adjusted labor expenses in Sub-Account 561.170 have remained relatively stable with 2009 being the highest recorded expense level. Additional funding to address NERC reliability standards is not required and SCE has embedded costs that it can allocate in the test year to address its work activities associated with the NERC reliability standards.

DRA asked SCE for additional information on its requested increase for additional staffing that were associated with the $1.585 million expense increase in Sub-Account 561.170.

SCE's response:

> As we discuss in testimony, we have not yet staffed our Alternate Grid Control Center and part of our reason for planning to hire 10 employees is to do so. As mentioned in testimony, this new practice "provides a level of security in alignment with others in the area, such as the California ISO and the WECC Reliability Coordinator function".[554]

SCE's response doe not justify additional funding. Based on SCE's statements, it does not appear that SCE actually plans on having permanent staffing at its Alternate Grid Control Center in the test year, as it claims. SCE states "By manning the Alternate Grid Control Center with a minimal number of employees during times of highest risk". This is what SCE is

---

[552] In SCE's TY 2009 GRC SCE was authorized $10.691 million (in 2009 constant dollars) for FERC Account 561. Of that amount, $4.906 million was authorized to address activities recorded in Sub-Account 561.170 (the remainder of the authorized amount was to address activities in Sub-Account 561.210). SCE's 2009 recorded adjusted expenses for Sub-Account 561.170 is $4.472 million, which is less than authorized, and the embedded funding can be allocated in the test year for SCE's test year activities (DRA-SCE-TLG-067 question 1-b).

[553] SCE has embedded funding for this project and an example of SCE requesting funding in its TY 2009 GRC to address its NERC Critical Infrastructure project activities is shown in D.09-03-025 page 234.

[554] See, SCE's response to DRA-SCE-067-TLG q. 5.

currently doing, and additional staffing is not required. DRA's use of SCE's 2009 recorded adjusted expenses of $4.472 million as a basis for its test year estimate for Sub-Account 561.170 is a sufficient forecast for 2012 based on recent expense history.

562.170 – Transmission Substation Costs

SCE forecast $10.640 million for Sub-account 562.170 (Labor of $8.731 million and Non-Labor of $1.909 million) for its Transmission Substation Costs. SCE utilized the number of substations in its system and the total expenses recorded in Sub-Accounts 562.170 – Transmission Substation Costs, 582.170 – Distribution Substation Costs, and 560.170 – Transmission Substation Supervision Costs to calculate its total expense per substation. SCE used the average expenses per substation for the recorded period and multiplied it by its forecast of the number of substations expected in the system in 2012. SCE then allocated the costs to the three Sub-Accounts mentioned above by calculating a ratio of expenses.[555]

SCE's expenses fluctuated during the five year period (2005-2009) and DRA's used of a five year average addresses this fluctuation. DRA's forecast is $0.347 million less than SCE's test year estimate

DRA made a normalized adjustment to SCE's recorded adjusted historical expenses (2005-2009) of $15,369 recorded in Sub-Account 562.170 for ratemaking purposes. DRA's adjustment was made to remove discretionary costs associated with SCE's employee recognition program Spot Bonuses and Awards to Celebrate Excellence Recognition Points (ACE), which are inappropriate to charge to ratepayers. SCE's employee recognition programs provide no clear or identifiable benefit to ratepayers and are not necessary to operate the utility business.[556]

573.170 – Transmission Related Storm Costs

SCE forecast $3.731 million for Sub-Account 573.170 (Labor of $1.036 million and Non-Labor of $2.695 million) for its Transmission Related Storm Costs.[557] SCE's forecast of $3.731 million is an increase of $2.550 million or 215.92% over 2009 recorded adjusted

[555] Ex. SCE-3 Vol. 4, Part 5, Chapters I-II, page 26.

[556] In SCE's response to DRA-SCE-067-TLG question 2, SCE provided a spreadsheet, which included recorded adjusted expenses for 2005-2009 incurred for its employee recognition awards recorded to Sub-Account 562.170. DRA removed expenses totaling $15,369 from its test year estimate which was based on a five year average.

[557] Ex. SCE-3, Vol. 4, Part 5, Chapters I-II, page 39.

expenses of $1.181 million. DRA utilized a three year average (2007-2009) as a basis for its forecast of $1.312 million for SCE's Sub-account 573.170.

DRA utilized a three year average (2007-2009). DRA used these years in its estimate because they appear to be more normal and routine years compared to the recorded costs for the years 2005 and 2006. DRA notes that SCE's expenses declined each year between 2005 and 2008 by $6.761 million from $7.418 million in 2005 to $0.657 million in 2008. In 2009, SCE's expenses increased to $1.181 million. DRA's estimate of $1.312 million based on a three year average is a reasonable method to forecast SCE's test year expenses for Sub-Account 573.170.

582.170 – Distribution Substation Costs

SCE forecast $14.909 million for Sub-account 582.170 (Labor of $12.750 million and Non-Labor of $2.159 million) for its Distribution Substation Costs. SCE utilized the number of substations in its system and the total expenses recorded in Sub-Accounts 582.170 – Distribution Substation Costs, 562.170 – Transmission Substation Costs, and 560.170 – Transmission Substation Supervision Costs to calculate its total expense per substation. SCE used the average expenses per substation for the recorded period and multiplied it by its forecast of the number of substations expected in the system in 2012. SCE then allocated the costs to the three Sub-Accounts mentioned above by calculating a ratio of expenses.[558]

SCE's forecasting method is unnecessarily complicated and difficult to follow. DRA utilized a five year average (2005-2009) and forecast $14.425 million (Labor of $12.716 million and Non-Labor of $1.709 million) for Sub-Account 582.170 and is more reasonable when compared to SCE's method. DRA's forecast is $0.484 million less than SCE's test year estimate. SCE's expenses fluctuated during the five year period (2005-2009) and DRA's use of a five year average addresses this fluctuation.

DRA made a normalized adjustment to SCE's recorded adjusted historical expenses (2005-2009) of $13,121 recorded in Sub-Account 582.170 for ratemaking purposes. DRA's adjustment was made to remove discretionary costs associated with SCE's employee recognition program Spot Bonuses and Awards to Celebrate Excellence Recognition Points (ACE), which

[558] Ex. SCE-3 Vol. 4, Part 5, Chapters I-II, page 26.

are inappropriate to charge to ratepayers. SCE's employee recognition programs provide no clear or identifiable benefit to ratepayers and are not necessary to operate the utility business.[559]

583.170 – Overhead Line Operations

SCE forecast $4.722 million for Sub-Account 583.170 (Labor of $3.744 million and Non-Labor of $0.987 million) for its Distribution Line Operations expenses.[560] SCE's forecast of $4.722 million is an increase of $0.593 million or 14.36% over 2009 recorded adjusted expenses of $4.129 million. DRA utilized SCE's last recorded year, the highest level of expenditures for the five year period, as a basis for its forecast of $4.129 million for SCE's Sub-account 583.170.

SCE's expenses increased by $1.999 million between 2005 and 2009, with 2009 recording the highest level of expenditures of $4.129 million. SCE states that the increase is due to "increasing age and size of our distribution system" and the change in work activities.[561] The five year average is $3.274 million and the three year average (2007-2009) is $3.901 million. SCE's forecast was based on its historical and projected capital expenditures for breakdown maintenance. SCE's labor expenses are forecast to increase by $0.468 million in the test year from $3.276 million in 2009 to $3.744 million in the test year. The five year average (2005-2009) for recorded adjusted labor expenses is $2.219 million and the three year average (2007-2009) is $2.956 million. DRA notes that SCE's labor expenses increased by $1.604 million between 2005 and 2009. SCE did not provide any documentation that demonstrated that its current labor funding level, which includes an increase of $1.604 million, is insufficient to address its test year needs.[562]

DRA takes issue with SCE's forecast for Sub-Account 583.170 because the forecast is based on increases in SCE's proposed capital projects in the test year. DRA's test year estimates

---

[559] In SCE's response to DRA-SCE-067-TLG question 2, SCE provided a spreadsheet, which included recorded adjusted expenses for 2005-2009 incurred for its employee recognition awards recorded to Sub-Account 582.170. DRA removed expenses totaling $13,121 from its test year estimate which was based on a five year average.

[560] Ex. SCE-3, Vol. 4, Part 5, Chapters I-II, page 31.

[561] Ex. SCE-3, Vol. 4, Part 5, Chapters I-II, page 31.

[562] DRA requested additional information from SCE on why its current funding level, which included a labor expense increase during the historical period of $1.604 million, was insufficient to address its test years needs (DRA-SCE-067-TLG question 12-b).

for several of SCE's proposed capital projects[563] are lower than SCE's forecasts which SCE utilized to forecast its Sub-Account 583.170. If DRA does not make a corresponding adjustment to SCE's forecast for Sub-Account 583.170 the expenses would be overfunded.

DRA's test year estimate of $4.129 million based on SCE's 2009 recorded expenses, which is the highest level of expenses recorded for the five year period and is more than the three year and five year averages, is a reasonable test year estimate.

588.170 – Other Grid Operations Costs

SCE forecast $6.317 million for Sub-Account 588.170 (Labor of $4.745 million and Non-Labor of $1.572 million) for its Other Grid Operations Costs.[564] SCE's Sub-Account 588.170 includes test year forecasts for the following line items: Circuit Mapping, Outage Data Management, Street Light Mapping and Inventory and Other expenses (Informational meetings and employee recognition awards). The corresponding DRA estimate is $5.049 for SCE's Sub-Account 588.170.

SCE's expenses for the four line items recorded in Sub-Account 588.170 have, for the most part, fluctuated during the five year period (2005-2009). DRA analyzed the recorded adjusted expenses and the forecast estimates for each individual line item separately to calculate its test year estimate for Sub-Account 588.170. The methods DRA utilized addresses the fluctuations in the historical expenses and the lack of comparable historical data on the recorded adjusted expenses that SCE previously recorded in other Sub-Accounts and then transferred expenses to Sub-Account 588.170.

DRA forecast $1.446 million for SCE's line item for Circuit Mapping expenses by utilizing a five year average (2005-2009). DRA's estimate is $0.460 million less than SCE's estimate. SCE's Circuit Mapping expenses fluctuated slightly between 2005 and 2008 averaging $1.332 million for the four year period (2005-2008) before increasing by $0.552 million, from $1.354 million in 2008 to $1.906 million in 2009. SCE did not provide any verifiable or comparable historical expenses or a breakdown of the line item detail totaling the increase of $0.552 million for analysis. Therefore, DRA utilized a five year average to address fluctuations

[563] The detailed discussion and analysis on SCE's proposed capital projects for the test year and DRA's corresponding estimates for SCE's capital projects will be addressed in Exhibits DRA-6 and DRA-7.

[564] Ex. SCE-3, Vol. 4, Part 5, Chapters I-II, page 51.

and its concerns on the 40.77% increase between 2008 and 2009 for SCE's Circuit Mapping expenses.

DRA forecast $1.668 million for SCE's line item for Outage Data Management expenses by utilizing a three year average (2007-2009). DRA's estimate is $0.268 million less than SCE's estimate. SCE does not show any recorded expenses for 2005 and 2006 for its Outage Data Management line item and does not provide an explanation for why there is no recorded or comparable historical data in its testimony on this specific line item. Expenses increased between 2007-2009 but there are no specific line item detail, for review and analysis on the cause of the increases (i.e. increased work activities due to deferred maintenance, overtime, transfer of expenses from one Sub-Account to another with verifiable and comparable historical data, etc.). DRA's use of a three year average is reasonable and addresses concerns for the lack of verifiable and recorded adjusted data.

DRA forecast $1.185 million for SCE's line item for Street Light Mapping and Inventory expenses by utilizing SCE's 2009 recorded adjusted expenses. DRA's estimate is $0.268 million less than SCE's estimate. SCE's Street Light Mapping and Inventory expenses fluctuated between 2005 and 2009 averaging $1.148 million for the five year period (2005-2009) which is comparable to SCE's 2009 recorded adjusted expenses. SCE's 2009 recorded adjusted expenses is a reasonable test year estimate and since it is comparable to its five year average which incorporates fluctuations in expenses, it should be sufficient for SCE to address its test year activities.

DRA forecast $0.750 million for SCE's line item for Other expenses by utilizing a two year average (2008 and 2009) of SCE's recorded adjusted expenses. DRA's estimate is $0.272 million less than SCE's estimate. DRA's forecast includes a normalized adjustment of $0.208 million for ratemaking purposes. SCE's Other expenses include costs incurred for employee information meetings and employee recognition awards.[565]

DRA made a normalized adjustment to SCE's recorded adjusted historical expenses (2005-2009) of $0.208 million recorded in Sub-Account 588.170 for ratemaking purposes. DRA made this adjustment to remove discretionary costs associated with SCE's employee recognition program Spot Bonuses and Awards to Celebrate Excellence Recognition Points (ACE), which

[565] Ex. SCE-3, Vol. 4, Part 5, Chapters I-II, page 54.

are inappropriate to charge to ratepayers.[566] SCE's employee recognition programs provide no clear or identifiable benefit to ratepayers and are not necessary to operate the utility business.

SCE's Other expenses fluctuated slightly between 2005 and 2007 averaging $0.127 million for the three year period (2005-2007) before increasing by $0.670 million, from $0.122 million in 2007 to $0.792 million in 2009 or a 549% increase over 2007 expenses. DRA did not include 2005-2007 in its average due to the significant increase between 2007 and 2008. SCE did not provide any verifiable or comparable historical expenses or a breakdown of the line item detail totaling the increase of $0.670 million for analysis. In 2009, SCE's expenses increased to $0.917 million. DRA utilized a two year average to address the significant fluctuations and DRA's concerns about the 549% increase between 2007 and 2008 for SCE's Other expenses.

DRA's test year estimate of $5.049 million for Sub-Account 588.170 is a reasonable test year estimate and is more than the three year average of $4.787 million and five year average of $4.014 million.

593.170 – Breakdown Maintenance of Overhead Lines

SCE forecast $10.307 million for Sub-Account 593.170 (Labor of $7.880 million and Non-Labor of $2.427 million) for its Breakdown Maintenance of Distribution Lines expenses.[567] SCE's forecast of $10.307 million is an increase of $1.311 million or 14.57% over 2009 recorded adjusted expenses of $8.996 million. DRA utilized SCE's last recorded year as a basis for its forecast of $8.996 million for SCE's Sub-account 593.170.

SCE's expenses fluctuated during 2005-2009 and SCE states that the "costs recorded in Sub-Account 593.170 depend primarily on certain drivers outside our control" such as emergency work on failed transformers.[568] In 2009, SCE's recorded adjusted expenses increased by $1.966 million over 2008 expenses due to more breakdown maintenance work being performed, "a return to a more average year".[569] SCE's recorded adjusted expenses averaged $8.201 million over the five year period (2005-2009) and averaged $8.357 million

---

[566] SCE provided its historical expenses (2005-2009) which included line items for employee recognition awards in its response to DRA-SCE-067-TLG question 2. DRA removed $208,468: $75,105 from 2008 and removed $133,363 from 2009 expenses.

[567] Ex. SCE-3, Vol. 4, Part 5, Chapters I-II, page 36.

[568] Ex. SCE-3, Vol., 4 Part 5, Chapters I-II, page 31.

[569] Ex. SCE-3, Vol. 4, Part 5, Chapters I-II, page 37.

over the three year period (2007-2009). SCE's forecast was based on its historical and projected breakdown of capital maintenance.

DRA takes issue with SCE's forecast for Sub-Account 593.170 because the forecast is based on significant increases in SCE's proposed capital in the test year. Based on a review and analysis of SCE's recorded adjusted expenses in Sub-Account 593.170 for 2005-2009, there appears to be no correlation between the fluctuations in this account, which SCE claims are out of its control, and SCE's capital project expenditures. DRA's test year estimates for several of SCE's proposed capital projects[570] are lower than SCE's forecasts, which it utilized to forecast its Sub-Account 593.170 expenses. If DRA does not make a corresponding adjustment to SCE's forecast for Sub-Account 593.170 the expenses would be overfunded in the test year. DRA's test year estimate of $8.996 million based on SCE's 2009 recorded expenses, which is more than the five year average of $8.201 million and the three year average of $8.357 million, is a reasonable test year estimate.

598.170 – Distribution Related Storm Costs

SCE forecast $18.732 million for Sub-Account 598.170 (Labor of $7.029 million and Non-Labor of $11.703 million) for its Distribution Related Storm Costs.[571] SCE's forecast of $18.732 million is an increase of $9.727 million or 108.02% over 2009 recorded adjusted expenses of $9.005 million. DRA utilized SCE's last recorded year as a basis for its forecast of $9.005 million for SCE's Sub-Account 598.170.

DRA utilized SCE's last recorded year in its estimate because that year appears to be a more normal and routine year compared to the recorded costs for the years 2005-2008. DRA notes that SCE's expenses declined each year between 2006 and 2009 by $14.547 million from $23.552 million in 2006 to $9.005 million in 2009. DRA's estimate of $9.005 million based on SCE's recorded 2009 expense is a reasonable method to forecast SCE's test year expenses for Sub-Account 598.170.

Capital Expenditures

Most of SCE's capital request for the Grid Operations organization relates to the operation and maintenance of the street light system. This capital can be broken down into three

---

[570] The detailed discussion and analysis on SCE's proposed capital projects for the test year and DRA's corresponding estimates for SCE's capital projects will be addressed in Exhibits DRA-6 and DRA-7.

[571] Ex. SCE-3, Vol. 4, Part 5, Chapters I-II, page 40.

types of activities: (1) steel street light pole replacement; (2) the need to make simple replacements and repairs to street light fixtures; and (3) the need to make complicated repairs to street lights.[572]

5.10.1. Overview

DRA recommends the Commission adopt SCE's actual 2010 Grid Operations capital expenditures, rather than its 2010 projections. For 2011 and 2012 Grid Operations capital expenditures, the only remaining area of disagreement DRA has with SCE relates to SCE's cost projections for its Street Light Replacement program.

5.10.2. Street Light Replacement Program

For its Street Light Replacement Program, SCE forecast $10.0 million in 2010, $13.4 million in 2011, and $16.4 million in 2012.[573] DRA recommends the Commission adopt SCE's actual cost of $11.1 million, and DRA's forecasts of $10.9 million in 2011 and again in 2012.[574] SCE's TY 2012 forecast is based on replacing 4,000 steel streetlight poles.

The largest component of SCE's proposed Street Light Replacement program is its request for funding for steel street light pole replacements. SCE wants to increase the number of steel street light pole replacements to 4,000 in 2012.[575] According to SCE, this will allow the company to replace all of its steel poles over the next 20 years.[576] SCE claims that the aging of its steel street light poles and the continuing corrosion of these assets "...leads to an ongoing and urgent need to replace steel street light poles."[577] SCE also claims that its steel street light poles suffer from corrosion which can be quicker in areas close to the ocean.[578]

SCE's testimony does not substantiate any such "urgent" need. SCE has not provided the Commission with any documentation that shows the ages of its steel street light poles, their condition or their locations and climate. Nor does SCE's recent spending history demonstrate

---

[572] Ex. SCE-3, Vol. 4, Part 5 & 6, p.55, lines 3-11.

[573] Ex. SCE-3, Vol. 4, Part 5 &6, p. 56, Table I-6.

[574] Ex. DRA-7, p. 39, Table 7-15.

[575] Ex. DRA-7, p. 41, citing Response to DRA-SCE-141-MKB, Q. 5a.

[576] Ex. SCE-3, Vol. 4, Part 5 & 6, p. 57.

[577] Ex. SCE-3, Vol. 4, Part 5 & 6, p. 57.

[578] Ex. SCE-3, Vol. 4, Part 5 & 6, p. 57.

any sense of urgency. In fact, SCE's highest year of steel street light pole replacements was six years ago when SCE replaced 3,135 steel street lights.

As to the number of steel street light pole replacements, SCE's own data shows that SCE has not been replacing anything near 4,000 steel street light poles a year. In fact, during the last five years, SCE has never replaced 4,000 steel street light poles in any one year calendar, and in both 2005 and 2008, SCE replaced less than 1,000 steel street light poles.[579]

While SCE complains about the condition of its steel street light poles and seeks a massive increase in capital expenditures ostensibly to address it, SCE's spending over the past five years shows no strategic plan to replace steel street light poles. In short, SCE has not supported its request, and during this GRC cycle, this Commission should limit ratepayer funding of the Street Light Replacement program capital expenditures to $10.9 million for 2011 and test year 2012.

5.11. T&D – Distribution Construction and Maintenance

Operations and Maintenance Expenses - 583.140, 586.140, 587.140, 588.170, 593.170 & 594.170

SCE forecast $61.960 million for its Distribution Construction and Maintenance expenses.[580] SCE developed its forecast by utilizing its 2009 recorded adjusted expenses for Sub-Accounts 580.140, 583.140, 586.140, 587.140, 588.140, 593.140, and 594.140 plus incremental expenses for proposed projects and work activities. The corresponding DRA estimate for SCE's Distribution Construction and Maintenance expenses is $29.497 million, which is $32.463 million less than SCE's forecast.

583.140 – Construction – Related Expense

SCE forecast $0.735 million for Sub-Account 583.140 (Labor of $0.614 million and Non-Labor of $0.121 million).[581] SCE's forecast of $0.735 million is an increase of 26.29% over 2009 recorded adjusted expenses of $0.582 million. SCE's Sub-Account 583.140 includes the following line items: Civil Inspections, Warranty Inspections, and Switching. DRA utilized SCE's last recorded year as a basis for its forecast of $0.582 million for SCE's Sub-Account 583.140.

---

[579] Ex. DRA-7, p. 43, citing Response to DRA-SCE-141-MKB, Q/A. 4a.

[580] Ex. SCE-3, Vol. 4, Part 6, Chapters I-II, page 73.

[581] Ex. SCE-3, Vol. 4, Part 6, Chapters I-II, page 111.

SCE's recorded adjusted expenses for the three line items recorded in Sub-Account 583.140 have declined each year between 2007 and 2009 from $3.600 million in 2007 to $0.582 million in 2009. Based on this decline in its expenses, SCE utilized its 2009 recorded adjusted expenses as a basis to forecast its line items for Warranty Inspections and Switching expenses.[582] SCE utilized its forecast level of underground capital work to forecast its Civil Inspections expenses in the test year. SCE states "we took the last year recorded costs to perform civil construction inspections and divided it by the recorded underground capital work requiring inspection. We applied this percentage to the forecast capital work to calculate the required funding for civil inspections".[583]

SCE has embedded funding in its historical expenses to allocate towards this activity since it has eliminated the work activity associated with performing site readiness checks.[584] SCE's underground capital work may not be adopted as SCE proposed and DRA's test year estimates for several of SCE's proposed capital projects are lower than SCE's forecasts.[585] If DRA does not make a corresponding adjustment to SCE's forecast for Sub-Account 583.140 the expenses in the test year would be overfunded.

586.140 – Meter-Related Expense

SCE forecast $6.700 million for Sub-Account 586.140 (Labor of $2.675 million and Non-Labor of $4.025 million) for its Meter Related expenses.[586] SCE's forecast of $6.700 million is an increase of $1.117 million or 20% over 2009 recorded adjusted expenses of $5.583 million. SCE's Sub-Account 586.140 includes the following line items: Replacements, Sets, and Removals. DRA utilized SCE's last recorded year as a basis for its forecast of $5.583 million for SCE's Sub-Account 586.140.

> SCE's expenses have declined each year for the last four years (2006-2009) from $7.390 million in 2006 to $5.583 million in

[582] Ex. SCE-3, Vol. 4, Part 6, Chapters I-II, page 111.

[583] Ex. SCE-3, Vol. 4, Part 6, Chapters I-II, page 111.

[584] In response to DRA-SCE-074-TLG question 6-b, SCE stated that it had eliminated Site Readiness Checks. SCE was authorized funding for its Pre-Construction Site Readiness Checks in its TY 2009 GRC (09-03-025 page 81 to 82).

[585] The detailed discussion and analysis on SCE's proposed capital projects for the test year and DRA's corresponding estimates for SCE's capital projects are addressed in Exhibits DRA-6 and DRA-7.

[586] Ex. SCE-3, Vol. 4, Part 6, Chapters I-II, page 113.

> 2009. The decline in expenses is partly due to "the economic recession reduced demand in the housing market".[587]

Based on SCE's recent history, with the decline each year in expenses between 2006 and 2009 recorded in Sub-Account 586.140, SCE's forecast of $6.700 million appears to be overstated and should be denied. SCE's Meter Replacements of 107,868 recorded in 2009 were the highest over the five year period (2005-2009) and this increase in replacements could be related to the installations of SmartMeters. SCE's recorded Meter Sets of 35,264 and Meter Removals of 13,300 were the lowest for the five year period (2005-2009). DRA's forecast of $5.583 million based on SCE's 2009 recorded adjusted expenses is a reasonable test year method and is based on SCE's recent expense history.

587.140 – Service Guarantees

SCE proposes to continue its Customer Service Guarantee program that was adopted in D.04-07-022, but requests that a baseline of service guarantee credits of $670,000[588] for the test year be changed from being shareholder funded to requiring that customers fund the credits that are to be paid to customers who have been inconvenienced by SCE.[589] The service guarantee program requires SCE to pay rebates to customers for 1) failure to meet agreed-upon appointment times; 2) failure to provide service restoration within 24 hours; 3) failure to provide planned interruption notification; and 4) failure to timely and accurately report the first bill.

In D.06-05-016 which addressed SCE's 2006 GRC, SCE's service guarantee program was continued as adopted in D.04-07-022 with SCE's shareholders funding the credits. DRA recommends that SCE continue the service guarantee program adopted D.04-07-022 and that SCE's shareholders continue to fund the service guarantee credits. In D.06-05-016 the Commission stated:[590]

> Regarding the payments to customers, these are payments that result from the company not meeting its commitments to individual customers. If the company is unable to meet its

[587] Ex. SCE-03, Vol. 4, Part 6, Chapters I-II, 113.

[588] Ex. SCE-3, Vol. 4, Part 6, Chapters I-II, 115.

[589] Ex. SCE-3, Vol. 4, Part 6, Chapters I-II, 116.

[590] D.06-05-016 page 122. In SCE's TY 2009 GRC (D.09-03-025 page 94) the Commission continued the approach it adopted in SCE's TY 2006 GRC and assigned the liability for missed commitments to shareholders.

> commitments, the shareholders and not ratepayers should be responsible for reimbursing the inconvenienced customer.

DRA agrees that SCE's "shareholders and not ratepayers should be responsible for reimbursing the inconvenienced customer" and recommends no funding for SCE's Service Guarantees recorded to Sub-Account 587.140. SCE's proposal to have ratepayers fund baseline service guarantee credits should be denied.

588.140 – Miscellaneous Distribution Expense

SCE forecast $3.777 million for Sub-Account 588.140 (Labor of $2.875 million and Non-Labor of $0.902 million) for its Miscellaneous Distribution expenses.[591] SCE's Sub-Account 588.140 includes the following line items: Field Service Representatives Supervision, Informational Meetings, Recognition, and Stand-By Time. SCE utilized its 2009 recorded adjusted expenses as a basis to forecast its expenses for Field Service Representatives Supervision, Informational Meetings, and Stand-By Time, and utilized a five year average to forecast its Recognition expenses. DRA utilized SCE's last recorded year as a basis for its forecast of $3.006 million for SCE's Sub-Account 588.140.

DRA made a normalized adjustment to SCE's 2009 recorded adjusted expenses of $1.321 million recorded in Sub-Account 588.140 for ratemaking purposes. DRA's adjustment was made to remove discretionary costs associated with SCE's employee recognition program Spot Bonuses and Awards to Celebrate Excellence Recognition Points (ACE), which are inappropriate to charge to ratepayers.[592] SCE's employee recognition programs provide no clear or identifiable benefit to ratepayers and are not necessary to operate the utility business.

SCE's expenses fluctuated during the five year period (2005-2009), with 2009 recording the highest level of expenditures. The four year average (2005-2008) was $3.075 million before increasing by 26.89% related to employee recognition expenses. DRA's test year estimate of $3.006 million, utilizing SCE's 2009 recorded expenses, after the normalized adjustment, is comparable to SCE's recent expense history and is a reasonable test year estimate for SCE to address its test year activities recorded in Sub-Account 588.140.

---

[591] Ex. SCE-3, Vol. 4, Part 6, Chapters I-II, page 119.

[592] SCE provided its historical expenses (2005-2009) which included a line item for employee recognition. Ex. SCE-3, Vol. 4, part 6, Chapters I-II, page 120.

593.140 – Overhead Breakdown Expense

SCE forecast $28.803 million for Sub-Account 593.140 (Labor of $12.376 million and Non-Labor of $16.427 million) for its Overhead Breakdown expenses.[593] SCE's forecast of $28.803 million is an increase of $14.425 million or 100.33% over 2009 recorded adjusted expenses of $14.378 million. SCE's Sub-Account 593.140 includes the following line items: Breakdown Maintenance and Work Order Related Expense. DRA utilized a five year average (2005-2009) as a basis for its forecast of $10.172 million for SCE's Sub-Account 593.140.

SCE's test year forecast, which includes an increase of 100.33% over 2009 recorded adjusted expenses is excessive and is not justified based on historical expense levels. SCE's expenses fluctuated significantly during the five year period (2005-2009) with an average for the period of $10.172 million. SCE's recorded adjusted expenses decreased by $3.518 million between 2006 and 2008 and then increased by $6.475 million between 2008 and 2009 or by 81.93%.[594] The four year average (2005-2008), before the 81.93% increase in 2009 expenses over 2008 expenses, was $9.120 million. DRA requested additional information from SCE on its test year forecast.

DRA asked:[595]

> SCE forecast $28.803 million ($12.376 million for labor and $16.427 million for non-labor) for Sub-Account 593.140 for its TDBU Overhead Breakdown expenses. This is an increase of $14.425 million or 100.3% over 2009 recorded adjusted expenses

[593] Ex. SCE-3, Vol. 4, Part 6, Chapters I-II, page 122. Note that on page 122, SCE shows a test year forecast of $28.585 million on line 10 and shows a forecast of $28.803 million in Figure II-40.

[594] DRA attempted to analyze and evaluate specific detail on historical expenses that SCE claimed in its testimony have caused increases in order to compare them to SCE's test year forecast. When DRA identified the specific year and the specific amount of the increase and requested the specific detail to be reviewed, SCE responded with a computer dump which included five years of expense data (2005-2009) with lump sum amounts of unidentifiable line items. In the response SCE stated "The attached file, DRA-SCE-074m Q.10.g.xls contains a detailed and itemized list of all the expenses recorded to 593.140 – Overhead Breakdown Expense. Each line item contained in the file is supported by individual accounting entries that sum up to the detailed and itemized listing of expense recorded to this sub-account. The individual accounting entries are available for DRA's review at SCE's offices in Rosemead, California". SCE provided similar responses for several of DRA's data requests. The information DRA requested is information that SCE has provided to DRA in past GRCs, and it is information that directly impacts SCE's test year expense estimates. SCE's response did not state if SCE had pulled and organized the requested information as DRA requested in its data request or if SCE planned on presenting DRA with another data dump in Rosemead, California (DRA-SCE-074-TLG question 10-g). Due to time, staffing, and budget constraints, DRA was not able to go to Rosemead to look at information that SCE could have provided in a data request response.

[595] DRA-SCE-074-TLG question 10-i.

> of $14.378 million. SCE's labor expenses averaged $4.241 million over the five year period (2005-2009) and SCE's 2009 recorded adjusted labor expenses were $6.466 million. The five year average (2005-2009) for SCE's non-labor expenses were $5.931 million and SCE's 2009 recorded adjusted non-labor expenses were $7.912 million.
>
> Provide the documentation that demonstrates specifically how SCE incorporated the salary savings from employee retirements during the historical years into its test year labor forecast.

SCE's response:

> SCE did not incorporate salary savings from employee retirements into the test year forecast for Overhead Breakdown expense. The work in this sub-account is volume driven and is not based on headcount. Please see the response to DRA-SCE-074-TLG Q.10.b for an explanation of how the costs were forecast for this sub-account. Additionally, the employees who perform the work in this sub-account are represented employees who can only perform the work if they are trained and qualified. Qualifications to perform work is based on represented job classification and all employees within the same job classifications are paid the same wage.

DRA asked:[596]

> SCE states that its increase between 2007 and 2009 was "due to increased breakdown as our distribution continues to age". SCE's distribution system ages every year, and SCE has requested and received sufficient funding in its 2006 and 2009 GRCs to properly address maintenance, repairs, and infrastructure replacement. Provide the documentation that explains in detail the reason why SCE's breakdown maintenance is expected to increase expenses by 100.3% compared to historical years.

SCE's response:

> Please see testimony in SCE-03, Vol. 3, Pt. 3, beginning on page 2, for a discussion of increase in age of SCE's distribution system and response to 10.h for an explanation of the forecasting methodology for this sub-account. SCE is not clear what the basis is for the statement that "SCE has requested and received sufficient funding in its 2006 and 2009 GRCs to properly address maintenance, repairs and infrastructure replacement."

SCE's responses do not justify a test year increase of 100.33% over the 2009 base year, nor do they address incorporation of embedded costs for on-going and routine activities that are

[596] DRA-SCE-074-TLG question 10-f.

similar to activities that will be performed in test year. SCE's distribution system ages every year and SCE has requested and received funding in its 2006 and 2009 GRCs to properly maintain its system in a timely manner. SCE's requested increase for activities recorded in this Sub-Account in the test year is unreasonable based on prior funding and recent expense levels.

SCE's forecast method is confusing and difficult to follow, and more importantly does not appear to be directly tied to the recorded adjusted historical expenses which fluctuated during the five year period in Sub-Account 593.140.[597] DRA's use of a five year average (2005-2009) of SCE's recorded adjusted expenses for Sub-Account 593.140 is clear, straight-forward and captures the fluctuations in the expense levels during the historical period incurred for on-going and routine maintenance activities.[598]

To calculate its Work Order Related expense, SCE states "we took the forecast capital spending by work category,[599] subtracted the material costs based on historical data, and applied the related expense percentage used in our SAP accounting system for calculating related expense. To forecast the breakdown maintenance component of this sub-account, we calculated the historical percentage of capital breakdown to expense breakdown and applied this percentage to the forecast capital breakdown expenditures."[600]

SCE's use of its proposed capital forecast to calculate test year expense levels for Sub-Account 593.140, instead of relying on historical expense levels directly tied to routine and on-going expenses recorded to the Sub-Account unnecessarily increases its test year estimates in this Sub-Account and is a burden to ratepayers.

---

[597] SCE states "Breakdown maintenance expenses are not directly or causally related to capital expenditures, but they are closely correlated with certain types of capital". SCE states further that "Work-order related expenses are directly and causally related to capital expenditures" (DRA-SCE-074-TLG question 10-h).

[598] DRA requested a cost benefit analysis performed by SCE to justify its 91.40% labor increase proposed for the test year in Sub-Account 593.140. SCE stated "SCE does not perform a cost benefit analysis for its forecast of underground breakdown maintenance because this work is an operating requirement" (DRA-SCE-074-TLG question 10-h).

[599] SCE states "We have used the same capital expenditures as our cost driver for both overhead and underground since work is similar. The capital expenditures we have used are breakdown maintenance, claims, and emergency pole replacements in constant 2009 dollars" (DRA-SCE-074-TLG question 10-h).

[600] Ex. SCE-3, Vol. 4, Part 6, Chapter I-II, page 122.

594.140 – Underground Breakdown Expense

SCE forecast $18.622 million for Sub-Account 594.140 (Labor of $7.326 million and Non-Labor of $11.296 million) for its Underground Breakdown expenses.[601] SCE's forecast of $18.622 million is an increase of $7.883 million or 73.41% over 2009 recorded adjusted expenses of $10.739 million. SCE's Sub-Account 594.140 includes the following line items: Breakdown Maintenance and Work Order Related Expense. DRA utilized a five year average (2005-2009) as a basis for its forecast of $7.501 million for SCE's Sub-Account 594.140.

> SCE's test year forecast is excessive, not justified based on historical expense levels recorded in Sub-Account 594.140, and should be denied. SCE's expenses fluctuated during the five year period (2005-2009) with an average for the period of $7.501 million. SCE's recorded adjusted expenses were relatively stable between 2005 and 2007 with an average for the three year period of $6.395 million before increasing in 2008 by $1.667 million or 28.19%. In 2009, SCE's expenses increased by $3.159 million or 41.68% over 2008 expenses.[602] The four year average (2005-2008), before the 41.68% increase in 2009 expenses over 2008 expenses, was $6.692 million.

SCE's showing does not justify an increase of 73.41% in the test year relative to the 2009 base year, nor does it address incorporation of embedded costs for on-going and routine activities that are similar to activities that will be performed in test year. DRA's use of a five year average (2005-2009) of SCE's recorded adjusted expenses for Sub-Account 594.140 is more reasonable when compared to SCE's method. The five year average also captures the fluctuations in the expense levels during the historical period incurred for on-going and routine maintenance activities. SCE's forecast method is confusing and difficult to follow, and more importantly does not appear to be directly tied to the recorded adjusted historical expenses which fluctuated during the five year period in Sub-Account 594.140.[603]

---

[601] Ex. SCE-3, Vol. 4, Part 6, Chapters I-II, page 125. Note that on page 125, SCE shows a test year forecast of $18.464 million on line 10 and shows a forecast of $18.622 million in Figure II-41.

[602] SCE states that the increase in expenses between 2008 and 2009 were due to increased equipment failures and the installation and removals of 4kV cutovers and transformers (DRA-SCE-074-TLG question 11-h).

[603] SCE states "Breakdown maintenance expenses are not directly or causally related to capital expenditures, but they are closely correlated with certain types of capital". SCE states further that "Work-order related expenses are directly and causally related to capital expenditures" (DRA-SCE-074-TLG question 10-h).

SCE utilized three factors to calculate its related expense. SCE states that it "took the forecast capital spend by work category, removed the material costs based on historical data, and applied the related expense percentage used in our SAP accounting system for calculating related expense. To forecast the breakdown maintenance component of this sub-account we calculated the historical percentage of capital breakdown to expense breakdown and applied this percentage to the forecast capital breakdown expenditures."[604]

SCE's use of its proposed capital forecast to calculate test year expense levels for Sub-Account 594.140 instead of relying on historical expense levels directly tied to routine and on-going expenses recorded to Sub-Account 594.140 has unnecessarily increased its test year estimates in this Sub-Account and is a burden to ratepayers.

SCE's proposed capital request may not be adopted as forecast by SCE and DRA has made adjustments to SCE's capital forecast that results in a total that is lower than SCE's estimates.[605] If DRA does not make a corresponding adjustment to SCE's forecast for this line item, which SCE relied upon to calculate its test year estimate, the expenses would be significantly overfunded in the test year.

Capital Expenditures

SCE categorizes its Distribution Construction and Maintenance work as either planned or unplanned. Planned work falls into four categories (1) customer requests, (2) routine inspection and maintenance, (3) circuit upgrades, and (4) infrastructure improvements. Unplanned work is categorized as: (1) breakdown maintenance, (2) distribution equipment damaged by storms, and (3) distribution equipment damaged by third parties.[606]

5.11.1. Overview

DRA's recommendations use SCE's actual distribution construction and maintenance capital expenditures in 2010. DRA disputes SCE's projections for Breakdown Maintenance, and Tools and Work Equipment as discussed below.

---

[604] Ex. SCE-3, Vol. 4, Part 6, Chapters I-II, page 125

[605] The detailed discussion and analysis of SCE's proposed capital projects for the test year and DRA's corresponding estimates for SCE's capital projects will be addressed in Exhibits DRA-6 and DRA-7.

[606] Ex.SCE-3, Vol.4, Part 5 & 6, pp. 76-77, lines 25-4.

5.11.2. Breakdown Maintenance

For Breakdown Maintenance, SCE forecasts $104.6 million for 2011, and $111.4 million for 2012.[607] DRA recommends $99.0 million for 2011, and also for 2012. Breakdown Maintenance, for purposes of SCE's Distribution Construction and Maintenance Capital Expenditures forecasts, includes any capital equipment replaced as the result of equipment failure which has experienced a fault and can no longer carry current. SCE distinguishes this type of breakdown from storm and claim work in that it is driven by factors typically related to the condition of the existing equipment or an operating event that results in the failure, rather than some external event disruptive to the distribution system, such as rain, or a car hitting a pole.[608]

SCE separates its cost calculation into four groups: (1) overhead conductors; (2) underground cable; (3) overhead transformers; and, (4) underground transformers. SCE projected out the number of replacement units for the years 2010-2014 and multiplied the replacement units by the recorded 2009 average price to install each replacement unit. To predict how many of these assets will be replaced per year, SCE uses the following equation: "Assets Replaced = Total Assets * Failure Rate."[609] SCE is calculating its assets replaced based on its total assets.

DRA reviewed the documentation SCE provided regarding its calculations and did its own calculation of the correlation co-efficient between the total assets and the failure rate, the failure rate and the replacement units, and the total assets and the replacement units using the seven years of data SCE provided. The correlation co-efficient between total assets and replacements units for three of the four groups ranges from 0.4344876 to 0.6056005. These rates are too low for any legitimate forecast. An acceptable correlation co-efficient should be above 0.95 and analysts prefer to see sample sizes that are greater than 30. SCE used a sample size of 7 years of data.[610]

SCE's historical data shows that overhead conductor replacement units went down in two years, 2006 and 2009, and up in two years, 2007 and 2008. Underground cable replacement

---

[607] Ex. DRA-7, p. 46.

[608] Ex. DRA-7, p. 47.

[609] Id.

[610] Ex. DRA-7, p. 48.

units went down in two years, 2006 and 2009, and up in two years, 2007 and 2008. Overhead transformer replacement units went down in two years, 2007 and 2009, and up in two years, 2006 and 2008. Overhead transformer replacement units went down in two years, 2007 and 2009, and up in two years, 2006 and 2008. In addition, 2009 does not have the highest number of replacement units and all costs in 2009 are lower than the costs in 2007.[611]

Virtually all units went up in 2008 but went down in 2009. For the overhead conductors, the final units in 2009 are lower than 2007, and for underground transformers, the 2009 units are very close to the number replaced in 2007. DRA is aware that SCE may have little control over when something breaks down. The variability in the replacement units demonstrates that. Nonetheless, SCE has not demonstrated that its method provides a legitimate forecast.

DRA used the last three recorded years of data in SCE's filing (2007-2009) to determine the average replacement units and multiplied the 2009 recorded unit costs to arrive at its 2011 and 2012 breakdown maintenance capital expenditures.

DRA recommends that the Commission adopt DRA's three-year replacement unit formula in determining SCE's 2011 and 2012 breakdown maintenance capitalized expenditures in this GRC which amounts to $99.0 million in 2011 and TY 2012.

5.11.3. Tools and Work Equipment

For Tools and Work Equipment, SCE forecasts $3.1 million for 2011, and $3.1 million for 2012.[612] DRA recommends $2.1 million for 2011, and also for 2012. Tool and Work Equipment includes costs for acquisition and retirement of portable tools and work equipment that cost more than $1,000. SCE says that replacement tools and equipment that increase efficiency or technological improvements are also included.[613]

SCE claims that in 2009 it increased expenditures on tool purchases and replacements as part of its focus on safety and because of increased wear and tear resulting from an increase in work.[614] SCE used its 2009 historic capitalized expenditures as its 2010-2014 tools and work equipment forecast.

---

[611] Id.

[612] Ex. DRA-7, p. 46.

[613] Ex. SCE-3, Vol. 4, Part 5 & 6, p. 102, lines 1-9.

[614] Ex. SCE-3, Vol. 4, Part 5 & 6, p. 103. lines 7-9

SCE's Tools and Work Equipment actual capitalized expenditures went down in 2006 and 2007, and up in 2008 and 2009. SCE provided no documentation to show that this variability was due to purchases to improve safety or because of increased wear and tear on existing tools and work equipment.

Given the historical fluctuations in this account, DRA recommends the Commission adopt Tool and Work Equipment capitalized expenditures for 2011 & 2012 on a five-year average of SCE's 2005-2009 recorded costs, or $2.1 million.

5.12. T&D – Substation Construction and Maintenance Operations and Maintenance Expenses - 570.150, 588.150 & 592.150

SCE forecast $32.144 million for its Substation Construction and Maintenance expenses.[615] SCE developed its forecast by utilizing its 2009 recorded adjusted expenses for Sub-Accounts 562.150, 568.150, 569.150, 570.150, 582.150, 588.150, 590.150, 591.150, and 592.150 plus incremental expenses for proposed projects and work activities. The corresponding DRA estimate for SCE's Substation Construction and Maintenance expenses is $26.194 million, which is $5.950 million less than SCE's forecast. DRA takes issue with SCE's test year forecasts for the Sub-Accounts that are discussed below.

570.150 – Transmission Substation Inspection & Maintenance

SCE forecast $12.881 million for Sub-Account 570.150 (Labor of $6.352 million and Non-Labor of $6.529 million) for its Transmission Substation Inspection & Maintenance.[616] SCE's forecast of $12.881 million is an increase of $1.988 million or 18.25% over 2009 recorded adjusted expenses of $10.293 million. SCE's Sub-Account 570.150 includes the following line items: Circuit Breaker Maintenance Costs, Transformer Maintenance Costs, Relay Maintenance Costs, Miscellaneous Equipment Costs, and Capital Related Expense. DRA utilized SCE's last recorded year and a five year average as a basis for its forecast of $9.370 million for SCE's Sub-Account 570.150. DRA's estimate is $3.511 million less than SCE's forecast.

---

[615] Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 11. SCE shows a forecast of $31.831 million for its Substation Construction and Maintenance expenses on page 12, line three. This is an error. The test year forecast is $32.144 million (DRA-SCE-095-TLG questions 5).

[616] Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 34.

SCE's expenses for the four line items recorded in Sub-Account 570.150 have fluctuated during the five year period (2005-2009). DRA takes issue with the following line items included in the forecast for Sub-Account 570.150.

DRA forecast $1.655 million for SCE's line item for Transmission Circuit Breaker Maintenance expenses utilizing SCE's last recorded year as a basis.[617] SCE's expenses fluctuated slightly during the five year period (2005-2009) with an average for the period of $1.754 million and the three year average (2007-2009) of $1.728 million.[618]

SCE's forecast is based on its proposed capital projects in the test year. DRA's test year estimates for several of SCE's proposed capital projects are lower than SCE's forecasts which it utilized to forecast this line item included in Sub-Account 570.150.[619] If DRA does not make a corresponding adjustment to SCE's forecast for this line item the expenses would be overfunded in the test year. SCE has embedded costs in its historical expenses to address its test year activities. DRA's use of SCE's 2009 recorded adjusted expenses of $1.655 million is comparable to historical levels and is a reasonable test year estimate.

DRA forecast $2.237 million for SCE's line item for Transmission Relay Maintenance expenses utilizing SCE's last recorded year, the highest recorded for the five year period (2005-2009), as a basis.[620] SCE's expenses increased by $0.741 million between 2005 and 2009 from $1.496 million in 2005 to $2.237 million in 2009. The average for the five year period (2005-2009) is $1.670 million and the three year average (2007-2009) is $1.808 million. The increase in 2009 of $0.905 million over 2008 expenses was partly due to "increased relay testing".[621]

---

[617] SCE utilized its proposed capital projects for 2012-2014 and a five year average of historical cost-per-circuit breaker as a basis for its test year forecast (Ex. SCE-03, Volume 4, Part 7, Chapters I-II, page 17).

[618] The Circuit Breaker Mechanism Maintenance (MM) SCE completed fluctuated during 2005-2009 with an average for the period of 532 Transmission MMs performed. SCE does not track the associated expenses for MMs separately (DRA-SCE-095-TLG question 8-g).

[619] The detailed discussion and analysis of SCE's proposed capital projects for the test year and DRA's corresponding estimates for SCE's capital projects will be addressed in Exhibits DRA-6 and DRA-7.

[620] SCE utilized its proposed capital projects for 2012-2014 as a basis for its test year forecast (Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 26).

[621] Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 25. SCE maintained and inspected an average of 2,533 Transmission Relays between 2005-2009 (DRA-SCE-095-TLG question 9-e).

SCE's request for an additional $0.593 million or 26.51% over 2009 expenses is not justified. SCE states that "multiple relay positions are being replaced by one single relay".[622] The single relays are "more reliable digital relays".[623] SCE should see some efficiency gains with a corresponding decrease in maintenance costs in the test year. SCE states "one micro-processor relay replaces many electro-mechanical relay units which drives down our volume of relay routine inspection and maintenance, but increases the complexity and duration of each activity".[624]

SCE states that "new NERC requirements have classified 115 kV relays as bulk power relays, which are now subject to NERC maintenance standards".[625] DRA discovered in a meeting on February 10, 2011 between DRA and SCE that SCE has been incurring costs related to "new and changing NERC reliability standards" during the historical period, and that although SCE has been incurring expenses it has not separately tracked those embedded costs in TDBU.[626] Additional funding to address NERC reliability standards is not required and SCE has embedded costs that it can allocate in the test year to address its work activities associated with the NERC reliability standards.

SCE's forecast is also based on its proposed capital projects in the test year. DRA's test year estimates for several of SCE's proposed capital projects are lower than SCE's forecasts which it utilized to forecast this line item included in Sub-Account 570.150.[627] If DRA does not make a corresponding adjustment to SCE's forecast for this line item the expenses would be overfunded in the test year. SCE should have embedded costs, due to the decrease in the volume of relays and the efficiency gains, to address its test year activities. DRA's use of SCE's 2009 recorded adjusted expenses of $2.237 million is more than SCE's five year average (2005-2009)

---

[622] Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 24. DRA notes that SCE has been installing the newer mircroprocessor based relays since the late 1980's (DRA-SCE-095-TLG question 9-f). SCE states "As relays have been replaced on the SCE system from electro-mechanical to microprocessor, the frequency by which they are inspected and tested have been reduced, yet the level of effort required during these inspections has increased" (DRA-SCE-095-TLG question 9-i).

[623] Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 25.

[624] Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 23.

[625] Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 26.

[626] SCE has embedded funding for this project and an example of SCE requesting funding in its TY 2009 GRC to address its NERC Critical Infrastructure project activities is shown in D.09-03-025 page 234.

[627] The detailed discussion and analysis on SCE's proposed capital projects for the test year and DRA's corresponding estimates for SCE's capital projects will be addressed in Exhibits DRA-6 and DRA-7.

of $1.670 million and its three year average (2007-2009) of $1.808 million, and is a reasonable test year estimate.

DRA forecast $2.709 million for SCE's line item for Transmission Miscellaneous Equipment Maintenance expenses utilizing SCE's last recorded year as a basis.[628] SCE's expenses declined by $0.609 million between 2007 and 2009 from $3.399 million in 2007 to $2.790 million in 2009. SCE's request for an additional $0.445 million or 15.95% over 2009 expenses is not justified. SCE states that the "number of transmission substations maintained by SC&M is expected to increase to 60".[629]

SCE's forecast is based on its proposed capital projects in the test year. DRA's test year estimates for several of SCE's proposed capital projects are lower than SCE's forecasts which it utilized to forecast this line item included in Sub-Account 570.150.[630] If DRA does not make a corresponding adjustment to SCE's forecast for this line item the expenses would be overfunded in the test year. SCE should have embedded costs in its historical expenses from completed projects that it can allocate funding to address its test year activities.[631] DRA's use of SCE's 2009 recorded adjusted expenses of $2.790 million is a reasonable test year estimate.

DRA forecast $1.991 million for SCE's line item for Transmission Capital Related expenses utilizing a five year average (2005-2009) as a basis.[632] SCE's recorded expenses fluctuated significantly between 2005 and 2009. SCE's calculated ratio for its capital expenditures associated with expenses recorded in Sub Account 570.150 "fluctuates from year-to-year driven by the inherent variability in the work".[633] SCE utilized "a 2005 to 2009 weighted

---

[628] SCE's test year forecast is based on its cost per substation (Ex. SCE-03, Volume 4, Part 7, Chapters I-II, page 28).

[629] Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 30.

[630] The detailed discussion and analysis on SCE's proposed capital projects for the test year and DRA's corresponding estimates for SCE's capital projects will be addressed in Exhibits DRA-6 and DRA-7.

[631] In SCE's TY 2009 GRC, it utilized Sub-Account 570.400 to record its Transmission Miscellaneous Maintenance expenses. In its TY 2012 GRC, SCE records these expenses to Sub-Account 570.150. SCE should have embedded funding from completed projects (i.e. Cable Trench Cover replacement project, Switchrack Lighting replacement project, etc.). DRA also notes that SCE's recorded adjusted 2009 expenses in Sub-Account 570.150 of $2.790 million is less than its authorized amount in its 2009 GRC for these activities (D.09-03-025 page 65 through 68).

[632] SCE utilized its proposed capital projects for 2012-2014 as a basis for its test year forecast (Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 26).

[633] Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 32.

average ratio of 1.1 percent" because its "related expense to capital expenditure ratio has fluctuated over the last five years".[634]

SCE's request for an additional $1.111 million or 35.44% over 2009 expenses is not justified. SCE has embedded funding in its historical expenses to address its test year activities. DRA requested additional information from SCE on its embedded funding.

DRA asked:[635]

> In SCE's 2009 GRC, SCE requested $8.805 million for Transmission Substation Miscellaneous Equipment (which included funding for capital related expenses) in Sub-Account 570.400. SCE was authorized approximately $7.999 million of its request, and a portion of the authorized amount was for additional funding for SCE's capital related expenses. Provide the documentation that explains in detail and demonstrates where SCE recorded the additional funding it was authorized for capital related expenses because it does not appear to DRA to be shown in SCE's Figure I-12. (See D.09-03-025 page 68).

SCE's response:

> As stated on page 11 of SCE-01, "The Commission expects SCE to manage its business between general rate case test years to optimize service to our customers and work towards realizing our authorized rate of return. In 2009, like nearly every other year, our recorded expenses varied from the specific categories like in the 2009 GRC". SCE does not specifically allocate or transfer authorized costs from one GRC sub-account to another. GRC authorized revenues are allocated through the SCE budgeting process.

SCE's recorded adjusted expenses increased by $2.093 million or 200.86% between 2008 and 2009. SCE states it "did not forecast expenses in this work category as an increment over 2009 recorded expenses, but rather as a "bottoms-up" forecast based on the expected volume of capital work and expected ratio of capital expenditure to capital related expense".[636]

DRA's test year estimates for several of SCE's proposed capital projects are lower than SCE's forecasts which it utilized to forecast this line item included in Sub-Account 570.150.[637] If DRA does not make a corresponding adjustment to SCE's forecast for this line item the expenses would be overfunded in the test year. SCE should have embedded costs to address its

---

[634] Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 33.

[635] DRA-SCE-095-TLG question12-b.

[636] DRA-SCE-095-TLG question 12-a.

[637] The detailed discussion and analysis on SCE's proposed capital projects for the test year and DRA's corresponding estimates for SCE's capital projects will be addressed in Exhibits DRA-6 and DRA-7.

test year activities. DRA's forecast of $1.991 million utilizing a five year average (2005-2009) addresses the inherent variability and fluctuations in this line item and is a reasonable test year estimate.

588.150 – Miscellaneous Substation Expenses

SCE forecast $0.674 million for Sub-Account 588.150 (Labor of $0.233 million and Non-Labor of $0.441 million) for its Miscellaneous Substation expenses.[638] DRA utilized a five year average (2005-2009) as a basis for its forecast of $0.249 million for SCE's Sub-Account 588.150. DRA's forecast is $0.425 million lower than SCE's forecast. SCE states that its expenses recorded to Sub-Account 588.150 "primarily includes payments to IT Business Unit for services provided, and employee recognition" and that its labor and non labor expenses recorded in this Sub-Account include employee recognition programs.[639]

DRA made a normalized adjustment to SCE's recorded adjusted historical expenses (2005-2009) of $0.425 million recorded in Sub-Account 588.150 for ratemaking purposes.[640] DRA's adjustment was made to remove discretionary costs associated with SCE's employee recognition program (i.e., Spot Bonuses and Awards to Celebrate Excellence Recognition Points (ACE), etc.), which are inappropriate to charge to ratepayers. SCE's employee recognition programs provide no clear or identifiable benefit to ratepayers and are not necessary to operate the utility business.

592.150 – Distribution Substation Inspection & Maintenance

SCE forecast $11.761 million for Sub-Account 592.150 (Labor of $6.924 million and Non-Labor of $4.837 million) for its Distribution Substation Inspection & Maintenance.[641] SCE's forecast of $11.761 million is an increase of $1.723 million or 17.16% more than its 2009

---

[638] Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 43.

[639] Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 42 and 43.

[640] SCE provided costs incurred for employee recognition for 2005 through 2009. In SCE's response to DRA-SCE-095-TLG question 2, SCE provided historical expenses which included employee recognition. DRA compared the two responses and the numbers do not match for employee recognition. SCE states that Sub-Account 588.150 primarily records expenses for its IT and employee recognition expenses and provided its historical expenses for its IT costs in DRA-SCE-095-TLG question 6-j. Based on SCE's testimony and information provided in SCE's responses, DRA believes that SCE's employee recognition expenses incurred are higher than SCE reported. Therefore DRA calculated its test year estimate by utilizing a five year average (2005-2009) of SCE's expenses incurred for IT services provided in its response to DRA-SCE-095-TLG question 6-j (DRA-SCE-095-TLG question 6-g).

[641] Ex. SCE-03, Volume 4, Part 7, Chapters I-II, page 35.

recorded adjusted expenses of $10.038 million. SCE's Sub-Account 592.150 includes the following line items: Circuit Breaker Maintenance Costs, Transformer Maintenance Costs, Relay Maintenance Costs, and Miscellaneous Equipment Costs. DRA utilized SCE's last recorded year as a basis for its forecast of $9.747 million for SCE's Sub-Account 592.150.

SCE's expenses for the four line items recorded in Sub-Account 592.150 have fluctuated during the five year period (2005-2009). DRA takes issue with the following line items included in the forecast for Sub-Account 592.150.

DRA forecast $3.257 million for SCE's line item for Distribution Circuit Breaker Maintenance expenses utilizing SCE's last recorded year as a basis.[642] SCE's expenses declined each year between 2006 and 2008 from $3.473 million in 2006 to $2.936 million in 2008 and then increased by $0.321 million in 2009 to $3.257 million. The average for the five year period (2005-2009) is $3.251 million and the three year average (2007-2009) is $3.135 million.[643]

SCE's forecast is based on its proposed capital projects in the test year. DRA's test year estimates for several of SCE's proposed capital projects are lower than SCE's forecasts which it utilized to forecast this line item included in Sub-Account 592.150.[644] If DRA does not make a corresponding adjustment to SCE's forecast for this line item the expenses would be overfunded in the test year. SCE has embedded costs in its historical expenses to address its test year activities.

DRA's use of SCE's 2009 recorded adjusted expenses of $3.257 million is comparable to SCE's five year average (2005-2009) of $3.251 million and its three year average (2007-2009) of $3.135 million, and is a reasonable test year estimate.

DRA forecast $1.461 million for SCE's line item for Distribution Relay Maintenance expenses utilizing SCE's last recorded year, the highest recorded for the five year period (2005-2009), as a basis.[645] SCE's expenses increased by $0.893 million between 2005 and 2009

---

[642] SCE utilized its proposed capital projects for 2012-2014 and a five year average of historical cost-per-circuit breaker as a basis for its test year forecast (Ex. SCE-03, Volume 4, Part 7, Chapters I-II, page 17).

[643] The Circuit Breaker Mechanism Maintenance (MM) SCE completed fluctuated during 2005-2009 with an average for the period of 3,295 Distribution MMs performed. SCE does not track the associated expenses for MMs separately (DRA-SCE-095-TLG question 8-g).

[644] The detailed discussion and analysis on SCE's proposed capital projects for the test year and DRA's corresponding estimates for SCE's capital projects will be addressed in Exhibits DRA-6 and DRA-7.

[645] SCE utilized its proposed capital projects for 2012-2014 as a basis for its test year forecast (Ex. SCE-03, Volume 4, Part 7, Chapters I-II, page 26).

from $0.568 million in 2005 to $1.461 million in 2009. The average for the five year period (2005-2009) is $0.936 million and the three year average (2007-2009) is $1.111 million. The increase in 2009 of $0.408 million over 2008 expenses was partly due to "increased relay testing".[646]

SCE's request for an additional $0.483 million or 33.06% over 2009 expenses is not justified. SCE states that "multiple relay positions are being replaced by one single relay".[647] The single relays are "more reliable digital relays".[648] Based on this, DRA believes that SCE should see some efficiency gains and a corresponding decrease in maintenance costs in the test year. SCE states "one micro-processor relay replaces many electro-mechanical relay units which drives down our volume of relay routine inspection and maintenance, but increases the complexity and duration of each activity".[649]

SCE states that "two new NERC regulations require supplementary maintenance associated with substation protection equipment" which require input calibration of current transformers and annual re-set of passwords on relays.[650] DRA discovered in a meeting on February 10, 2011 between DRA and SCE that SCE has been incurring costs related to "new and changing NERC reliability standards" during the historical period, and that although SCE has been incurring expenses it has not separately tracked those embedded costs in TDBU.[651] Additional funding to address NERC reliability standards is not required and SCE has embedded costs that it can allocate in the test year to address its work activities associated with the NERC reliability standards.

SCE's forecast is also based on its proposed capital projects in the test year. DRA's test year estimates for several of SCE's proposed capital projects are lower than SCE's forecasts

---

[646] Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 25. SCE maintained and inspected an average of 3,262 Distribution Relays between 2005-2009 (DRA-SCE-095-TLG question 9-e).

[647] Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 24. DRA notes that SCE has been installing the newer mircroprocessor based relays since the late 1980's (DRA-SCE-095-TLG question 9-f). SCE states "As relays have been replaced on the SCE system from electro-mechanical to microprocessor, the frequency by which they are inspected and tested have been reduced, yet the level of effort required during these inspections has increased" (DRA-SCE-095-TLG question 9-i).

[648] Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 25.

[649] Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 23.

[650] Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 26.

[651] SCE has embedded funding for this project and an example of SCE requesting funding in its 2009 GRC to address its NERC Critical Infrastructure project activities is shown in D.09-03-025 page 234.

which it utilized to forecast this line item included in Sub-Account 592.150.[652] If DRA does not make a corresponding adjustment to SCE's forecast for this line item the expenses would be overfunded in the test year. SCE should have embedded costs, due to the decrease in the volume of relays and the efficiency gains, to address its test activities.

DRA's use of SCE's 2009 recorded adjusted expenses of $1.461 million results in a forecast that is more than SCE's five year average (2005-2009) of $0.936 million and its three year average (2007-2009) of $1.111 million, and is a reasonable test year estimate.

DRA forecast $3.541 million for SCE's line item for Distribution Miscellaneous Equipment Maintenance expenses utilizing SCE's last recorded year as a basis.[653] SCE's expenses declined by $2.259 million between 2007 and 2009 from $5.800 million in 2007 to $3.541 million in 2009.

SCE's request for an additional $1.327 million or 37.48% over 2009 expenses is not justified. SCE states that the "number of distribution substations that SC&M has to maintain will increase as new Load Growth projects are implemented".[654] SCE's forecast is based on its proposed Load Growth capital projects in the test year. DRA's test year estimates for several of SCE's proposed capital projects are lower than SCE's forecasts which it utilized to forecast this line item included in Sub-Account 592.150.[655] If DRA does not make a corresponding adjustment to SCE's forecast for this line item the expenses would be overfunded in the test year. SCE should have embedded costs in its historical expenses from completed projects that it can allocate funding to address its test activities.[656] DRA's use of SCE's 2009 recorded adjusted expenses of $3.541 million is a reasonable test year estimate.

---

[652] The detailed discussion and analysis on SCE's proposed capital projects for the test year and DRA's corresponding estimates for SCE's capital projects will be addressed in Exhibits DRA-6 and DRA-7.

[653] SCE's test year forecast is based on its cost per substation (Ex. SCE-03, Volume 4, Part 7, Chapters I-II, page 28).

[654] Ex. SCE-3, Vol. 4, Part 7, Chapters I-II, page 31.

[655] The detailed discussion and analysis on SCE's proposed capital projects for the test year and DRA's corresponding estimates for SCE's capital projects will be addressed in Exhibits DRA-6 and DRA-7.

[656] In SCE's TY 2009 GRC, it utilized Sub-Account 592.400 to record its Distribution Miscellaneous Maintenance expenses. In its TY 2012 GRC SCE records these expenses to Sub-Account 592.150. SCE should have embedded funding from completed projects (i.e. Trench Cover replacement project, Switchrack Lighting replacement project, etc.). DRA also notes that SCE's recorded adjusted 2009 expenses in Sub-Account 592.150 of $3.541 million is less than its 2006 recorded adjusted expenses and less than it was authorized in its 2009 GRC for these activities (D.09-03-025 page 96).

Capital Expenditures

For Substation Construction and Maintenance capital expenditures, SCE forecasts ratepayer funding in the mid to high $70 million range for the years 2010, 2011 and 2012.

For 2010, DRA recommends the Commission use SCE's actual 2010 capital expenditures of $58.7 million. For 2011 and 2012, DRA does not dispute SCE's forecasts for Substation Storm Capital or Substation Claims. DRA's recommendations for Substation Capital Maintenance, Substation Rule 20, and Substation Added Facilities.

5.12.1. Substation Capitalized Maintenance

For Substation Capitalized Maintenance, SCE forecasts $40.5 million for 2011 and $40.4 million for 2012. DRA recommends $33.2 million for 2011 and $33.2 million for 2012.

SCE says the Substation Capitalized Maintenance capital expenditures are associated with removal, replacement, and retirement of assets on a reactive basis. These replacements are driven by SCE's Substation Preventive Maintenance program, where imminent equipment failures or safety issues are detected. According to SCE, "Substation capital maintenance replacements predominantly involve like-for-like replacement."[657]

In SCE's request for substation capitalized maintenance miscellaneous equipment, SCE's 2011 forecast of $40.5 million jumps approximately $9.8 million over its 2010 estimate of $30.7 million. SCE's justification in a data response for this $9.8 million increase in miscellaneous equipment is ". . .to get back to 2007 level of spending, which was $16.506 million . . ."[658]

Neither SCE's testimony, nor its workpapers nor its data responses justifies the proposed increase. SCE's annual budget for 2010 miscellaneous equipment reflects capitalized expenditures of only $6 million. SCE's historical Substation Capital Maintenance capitalized expenditures range from a high of $39.8 million in 2007 to a low of $27.4 million in 2008. Because of the lack of documentation to support this requested increase, DRA is recommending that in 2011 and 2012, SCE be authorized recovery of its 5-year average Substation Capital Maintenance capital expenditures of $33.2 million. It should be noted that DRA's 2011 & 2012

[657] Ex. SCE-3, Vol. 4, Part 7 & 8, p.44, lines 11-16

[658] Ex. DRA-7, p. 52, citing Response to DRA-SCE-157-MKB, Q. 3a.

forecast exceeds SCE's actual capital expenditures in 2010 of $32.9 million before DRA's numbers are escalated.

5.12.2. Substation Rule 20

For Rule 20b and Rule 20c capital expenditures, SCE forecasts $0.5 million in 2011 and $0.5 million in 2012. DRA forecasts $0.2 million for 2011 and $0.2 million for 2012. Rule 20b and Rule 20c are tariffs that provide for the replacement of overhead facilities with underground equipment when requested by customers.[659]

SCE projected out Substation Rule 20b and 20c capital expenditures using a 5-year average. Since 2007, SCE's Substation Rule 20b and 20c capitalized expenditures have been declining. To take into account the recent changes in the California's economy, DRA recommends using the 2009 level of capital expenditures of $178,000 for 2011 and 2012 Substation Rule 20 b and 20c capitalized expenditures. It should be noted that 2010 actual Substation Rule 20b and 20c capital expenditures ($2,000) are substantially lower than SCE's 2009 capital expenditures.[660]

5.12.3. Substation Added Facilities

For Substation Added Facilities – SCE Funded, in its Direct testimony, SCE forecasted $13.9 million in 2011 and $13.5 million in 2012. DRA recommends $5.1 million in 2011 and $5.1 million in 2012.

For Substation Added Facilities – Customer Funded, in its Direct testimony, SCE forecasted $21.6 million in 2011 and $17.6 million in 2012. DRA recommends $4.9 million in 2011 and $4.9 million in 2012.[661]

It is DRA's understanding that in Rebuttal, SCE agrees with DRA's forecasts for Substation Added Facilities with one caveat: "[s]ince SCE's forecasts for OOR were linked to [SCE's] forecasts of Rule 20B and 20C capital expenditures, if any reduction is adopted for the capital expenditures, corresponding reductions must also be accepted for the OOR forecast."[662]

DRA agrees.

---

[659] Ex. SCE-3, Vol. 4, Part 7 & 8, p. 48, lines 1-3.

[660] Ex. DRA-7, p. 55.

[661] Ex. DRA-7, p. 51.

[662] Ex. SCE-18, Vol. 4, Part 7, p. 7.

5.13. T&D – Transmission

Operations and Maintenance Expenses - 563.160, 564.160, 566.160, 567.160 & 571.160

SCE forecast $56.364 million for its Transmission expenses.[663] SCE developed its forecast by utilizing its 2009 recorded adjusted expenses for Sub-Accounts 563.160, 564.160, 566.160, 567.160, and 571.160 plus incremental expenses for proposed projects and work activities. The corresponding DRA estimate for SCE's Transmission expenses is $45.360 million, which is $11.004 million less than SCE's forecast.

563.160 – Overhead Transmission Line Inspection

SCE forecast $3.851 million for Sub-Account 563.160 (Labor of $2.336 million and Non-Labor of $1.515 million) for its Overhead Transmission Line expenses.[664] SCE's forecast of $3.851 million is an increase of $1.181 million or 44.23% over 2009 recorded adjusted expenses of $2.670 million. SCE's Sub-Account 563.160 includes the following line items: Overhead Transmission Line Inspection Expense and Intrusive Pole Inspections. DRA utilized SCE's last recorded year as a basis for its forecast of $2.683 million for SCE's Sub-Account 563.160.

SCE's request for an increase of 44.23% over 2009 recorded adjusted expenses is not justified. SCE's expenses for two line items recorded in Sub-Account 563.160 fluctuated during the five year period (2005-2009). DRA analyzed the recorded adjusted expenses and the forecast estimates for each individual line item to calculate its test year estimates for Sub-Account 563.160.

DRA forecast $2.609 million for SCE's line item for Overhead Transmission Line Inspection expenses utilizing SCE's last recorded year as a basis. SCE's expenses were relatively stable between 2005 and 2006 with an average for the two years of $2.655 million. In 2007 SCE's expenses increased by $1.091 million over 2006 expenses due in part to an increase in wildfires. SCE's expenses declined each year between 2007 and 2009 from $3.927 million in 2007 to $2.609 million in 2009, back down to SCE's historical levels comparable to the expenses

[663] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 78.

[664] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 107.

recorded in 2005 and 2006. SCE states "Overall, the expenses in 2008 were higher than the historical average because of the many wildfires that occurred in 2008".[665]

SCE's overhead inspection expense forecast is based on a five-year average of annual inspection expenses-per-transmission line miles for 2005-2009 and SCE forecast adding additional line miles in 2010-2012. Based on SCE's recorded adjusted expenses, the amount of line miles in SCE's system does not appear to have caused major increases in historical expenses (2005-2009) recorded to Sub-Account 563.160.[666] Further, SCE has embedded funding in its historical expenses to address its Transmission Line Patrols. It is inappropriate to require increased ratepayer funding for activities that already have costs embedded in SCE's historical expenses; no additional ratepayer funding should be required over SCE's 2009 recorded adjusted expenses of $2.609 million.[667] DRA's use of SCE's 2009 recorded adjusted expenses of $2.609 million is a reasonable test year estimate for SCE to address the activities recorded to this Sub-Account.

DRA forecast $74,000 for SCE's line item for Intrusive Pole Inspections expenses utilizing a two year average (2008 and 2009). SCE's forecast of $0.680 million is an increase of 103% over 2009 recorded adjusted expenses. SCE only provided two years of recorded adjusted expenses (2008-2009) in its Figure II-38 for review and analysis.[668] SCE states "SCE began specifically tracking transmission intrusive pole inspection program costs in 2008".[669] SCE did not provide information in its testimony or data request responses to further discuss and explain in detail the meaning of that statement. SCE also did not provide any documentation that

---

[665] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 83.

[666] SCE made a similar argument in its TY 2009 GRC regarding expense increases in patrols due to its forecast increase in line miles. SCE was authorized additional funding to address its Transmission Line Patrols, however, DRA notes that SCE's 2009 recorded adjusted expenses of $2.609 million recorded to Sub-Account 563.160 do not reflect the increase in authorized funding or the increase in expenses due to increasing line miles (D.09-03-025 page 56).

[667] SCE has embedding funding in its historical expenses that can be allocated towards projects recording to Sub-Account 563.160. In SCE's TY 2009 GRC (D.09-03-025 page 55 to 56), SCE utilized Sub-Account 563.100 to record work activities and associated expenses that are now recorded in its TY 2012 GRC to Sub-Account 563.160. SCE was authorized approximately $18.851 million (in 2009 constant dollars) for Sub-Account 563.100, and of that amount, SCE's recorded adjusted 2009 expenses only show $6.093 million (2009 constant dollars). SCE does not state the Sub-Accounts where the funding was allocated and recorded (DRA-SCE-085-TLG question 1-a).

[668] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 85.

[669] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 86.

explained in detail why it did not provide recorded adjusted expenses in its GRC testimony, where it was requesting ratepayer funding, for the years 2005-2007 for review and analysis.[670]

SCE has embedded funding in its historical expenses that it can allocate in the test year to address its Transmission Intrusive Pole inspections. It is inappropriate to require increased ratepayer funding for activities that already have costs embedded in SCE's historical expenses; no additional funding should be required of ratepayers.

564.160 – Underground Transmission Line Inspection

SCE forecast $0.991 million for Sub-Account 564.160 (Labor of $0.742 million and Non-Labor of $0.249 million) for its Underground Transmission Line Inspection expenses.[671] DRA utilized SCE's last recorded year as a basis for its forecast of $0.720 million for SCE's Sub-Account 564.160.

SCE's expenses were relatively stable between 2005 and 2006 with an average for the two years (2005-2006) of $0.734 million. In 2007, SCE's expenses increased by $0.426 million over 2006 expenses due in part to an increase in the "number of requests to locate and mark underground electric facilities".[672] SCE's expenses declined each year between 2007 and 2009 from $1.186 million in 2007 to $0.720 million in 2009, back down to SCE's historical levels comparable to the expenses recorded in 2005 and 2006.

SCE's underground inspection expense forecast is based on a five-year average of annual inspection expenses per underground transmission line miles for 2005-2009.[673] SCE's forecast includes adding additional line miles in 2010-2012. Based on SCE's recorded adjusted expenses the amount of line miles in SCE's system does not appear to have caused major increases in Sub-Account 564.160 during the historical period (2005-2009). Further, SCE has embedded funding

---

[670] In response to a data request, SCE provided recorded costs (which lacked support and the basis for the numbers), for 2005-2007 and transmission pole inspections lumped together with corrections. However, SCE did not provide any discussion regarding the two years of data provided in its testimony or the three years of missing data. SCE did not provide an explanation for the statement in its testimony that "SCE began specifically tracking transmission intrusive pole inspection program costs in 2008". Based on SCE's testimony and its response, DRA has concerns with relying on this information. SCE has embedded funding to address this activity in the test year and no additional ratepayer funding is required (DRA-SCE-085-TLG questions 5-a and 5-c).

[671] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 87.

[672] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 87.

[673] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 88.

in its historical expenses to address this activity in the test year.[674] It is inappropriate to require increased ratepayer funding for activities that already have costs embedded in SCE's historical expenses and no additional funding is required over SCE's 2009 recorded adjusted expenses of $0.720 million. DRA's use of SCE's 2009 recorded adjusted expenses of $0.720 million is a reasonable test year estimate for SCE to address the activities recorded to this Sub-Account.

566.160 – Transmission Miscellaneous Expense

SCE forecast $7.230 million for Sub-Account 566.160 (Labor of $4.702 million and Non-Labor of $2.528 million) for its Transmission Miscellaneous expenses.[675] SCE's forecast of $7.230 million is an increase of $1.632 million or 29.15% over 2009 recorded adjusted expenses of $5.598 million. SCE's Sub-Account 566.160 includes the following line items: Miscellaneous Transmission Expense and Other Expense. DRA utilized SCE's last recorded year as a basis for its forecast of $5.296 million for SCE's Sub-Account 566.160.

SCE's expenses for the two line items recorded in Sub-Account 566.160 fluctuated during the five year period (2005-2009). DRA analyzed the recorded adjusted expenses and the forecast estimates for each individual line item to calculate its test year estimate for Sub-Account 566.160.

DRA forecast $4.904 million for SCE's line item for Miscellaneous Transmission expenses utilizing SCE's last recorded year as a basis. SCE's expenses declined by $2.282 million between 2007 and 2009 from $7.186 million in 2007 to $4.904 million in 2009. The decreases in recorded expenses were due to SCE's "concentrated efforts on encroachment enforcement".[676]

SCE's forecast is based on its spending per transmission line mile in 2009 times the total line miles in 2010-2012, because the average spending has remained relatively constant the past two years and is expected to remain at this level going forward. Based on SCE's recorded adjusted expenses the amount of line miles in SCE's system does not appear to have caused major increases in Sub-Account 566.160 during the historical period (2005-2009). DRA requested additional information from SCE regarding its test year request.

---

[674] DRA-SCE-085-TLG question 1-b.

[675] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 108.

[676] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 102.

DRA asked:[677]

> Provide the documentation that explains in detail and demonstrates the relationship between SCE's total transmission line miles and its recorded adjusted expenses for Miscellaneous expenses for 2005 through 2009. Based on SCE's testimony, the increases and decreases between 2005 and 2009 were due specifically to "Corporate Real Estate support services for encroachment work".

SCE's response:

> SCE's land rights of way are found throughout SCE's transmission system, and TDBU and Corporate Real Estate are jointly responsible for inspecting and identifying encroachments and infractions on these properties throughout the transmission system. SCE finds that the total cost per transmission line mile is an appropriate basis for both assessing recorded costs and forecasting future costs in this activity.

DRA asked:[678]

> SCE forecast $5.140 million for its Miscellaneous expenses which is recorded in Sub-Account 566.160 and included in the forecast of $7.230 million. SCE's labor expenses recorded for Miscellaneous expenses increased by $1.369 million between 2005 and 2009.
>
> Provide the documentation that explains in detail and demonstrates why SCE's current funding level, which includes an increase of $1.369 million, is insufficient to address its work load in the test year.

SCE's response:

> The $0.124 million increase from 2009 to 2012 in labor expenses in this activity is based on the increased transmission line miles as shown in Figure II-44 of the testimony. SCE believes it is appropriate to request additional funding for this account because the workload for the activities will be increasing based on the new transmission lines.

SCE's responses do not explain the relationship between the decreases in recorded expenses for this line item during the historical period, and the increases in line miles, nor do they demonstrate that SCE's current funding level is insufficient. SCE has embedded costs in its historical expenses from completed projects that it can allocate to address its test year activities. DRA's use of SCE's 2009 recorded adjusted expenses of $4.904 million is comparable to SCE's recent expense levels and is a reasonable test year estimate.

---

[677] DRA-SCE-085-TLG question 6-f.

[678] DRA-SCE-085-TLG question 6-c.

SCE's forecast for the line item, Other Expenses of $2.090 million or 201.15% increase over 2009 recorded expenses of $0.694 million is not justified. SCE states "This account also includes the spot bonus and ACE awards program which are used to motivate and reward employees who perform additional responsibilities in an exceptional manner or take on tasks that require additional time commitments". SCE further states in regards to its Transmission Program that "if an employee volunteers for the program and commits to being trained for three years, a bonus and an opportunity to certify for Air Operations work is provided".[679]

DRA forecasts $0.392 million for SCE's line item for Other Expenses recorded to Sub-Account 566.160. DRA's test year estimate excludes SCE's test year forecast of $0.068 million for Employee Recognition and $1.630 million for its Transmission Program expenses (a multi-year bonus program provided to transmission linemen)[680] recorded in Sub-Account 566.160 for ratemaking purposes. DRA's adjustment removes discretionary costs associated with SCE's employee recognition program Spot Bonuses, Awards to Celebrate Excellence Recognition Points (ACE), and its multi-year bonus plan, all of which are inappropriate for ratepayer funding.[681] SCE's employee recognition programs provide no clear or identifiable benefit to ratepayers and is not necessary to operate the utility business. SCE can continue to offer these benefit programs to its employees at its shareholders expense.[682]

567.160 – Transmission Line Rents

SCE forecast $8.224 million for Sub-Account 567.160 (Non-Labor of $7.408 million and Other Exp of $0.816 million) for its Transmission Line Rents expenses.[683] SCE's forecast of $8.224 million is an increase of $2.686 million or 48.50% over 2009 recorded adjusted expenses of $5.538 million. DRA utilized SCE's last recorded year as a basis for its forecast of $5.538 million for SCE's Sub-Account 567.160.

---

[679] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II page 103.

[680] SCE utilized a Budget-Based method to calculate its test year forecast of $1.630 million for its Transmission Program (multi-year bonuses) which was established in 2009.

[681] In SCE's responses to DRA-SCE-085-TLG question 7-h and 7-g, SCE provided information on its Transmission Program expenses (a multi bonus program for linemen) that are recorded to Sub-Account 566.160.

[682] SCE's Air Operations and associated training costs as well as the salary for SCE's Transmission linemen are already funded in rates by ratepayers (DRA-SCE085-TLG question 7-j).

[683] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 105.

SCE's non-labor expenses fluctuated during the five year period (2005-2009) and increased by 56.46% in 2009 over 2008 expenses. The fluctuations during the five year period (2005-2009) were apparently due in part to "the timing of line rent payments" and increases in line rent contracts by the Bureau of Land Management and the U.S. Forest Service.[684]

SCE states that The Bureau of Land Management and U.S. Forest Service "implemented unprecedented rate increases late in 2008 for all rental periods beginning in 2009".[685] SCE provided DRA with a copy of the "Federal Register" issued by the Department of the Interior, Bureau of Land Management, which was issued on October 31, 2008. SCE did not provide DRA with specific documentation and reference material or the specific contracts (demonstrating the detailed breakdown of expenses and the direct impact on its test year forecast) relating directly to this document for DRA's review and analysis to determine the reasonableness of SCE's requested test year increase of 48.50%. SCE stated "There is no contract between SCE and the BLM, however attached is the final rule from the Bureau of Land Management documenting the increase in line rents for BLM land".[686]

SCE did not provide sufficient documentation to support additional ratepayer funding of 48.50% over 2009 recorded expenses of $5.538 million in the test year for Sub-Account 567.160. SCE has embedded funding in its historical expenses to address its line rent increases, since SCE's 2009 recorded adjusted TDBU O&M expenses were $48 million less than it was authorized in its 2009 GRC.[687] DRA's forecast of $5.538 million, utilizing SCE's 2009 recorded adjusted expense, the highest recorded for the five year period (2005-2009), is a reasonable method to forecast SCE's test year activities recorded to Sub-Account 567.160.

571.160 – Transmission Maintenance

SCE forecast $36.068 million for Sub-Account 571.160 (Labor of $10.937 million and Non-Labor of $25.131 million) for its Transmission Maintenance expenses.[688] DRA utilized SCE's last recorded year as a basis for its forecast of $31.123 million for SCE's Sub-Account 571.160.

---

[684] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 106.

[685] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 106.

[686] DRA-SCE-085-TLG question 13.

[687] Ex. SCE-3, Vol. 1, Chapters I-VI, page 20.

[688] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 109.

SCE's expenses for the four line items recorded in Sub-Account 571.160 fluctuated during the five year period (2005-2009). DRA takes issue with the following line items included in the forecast for Sub-Account 571.160.

DRA forecast $3.709 million for SCE's line item for Insulator Washing expenses utilizing SCE's last recorded year as a basis. SCE's expenses fluctuated between 2005 and 2009 with an average for the five year period (2005-2009) of $3.747 million. SCE's expenses declined between 2008 and 2009 by $0.815 million from $4.524 million in 2008 to $3.709 million in 2009. The decline was due to "the retirement of several older wash vehicles. These older vehicles had remained in service for an extended period of time while problems with newer wash vehicles being brought into service were identified and corrected. Once the newer vehicles began performing at acceptable levels, the older vehicles were retired".[689]

SCE's Insulator Washing expense forecast is based on a five-year average of annual inspection expenses per transmission line mile for 2005-2009.[690] SCE forecast adding additional line miles in 2010-2012. Based on SCE's recorded adjusted expenses, the amount of line miles in SCE's system does not appear to have caused major increases in historical expenses (2005-2009) recorded to Sub-Account 571.160. DRA requested additional information from SCE on its test year forecast.

DRA asked:[691]

> In SCE's 2009 GRC SCE requested and was authorized (D.09-03-025 page 71) an additional $2.007 million for Insulator Washing. This additional funding of $2.007 million was in addition to its 2006 recorded adjusted expenses for insulator washing of $3.035 million. Provide the documentation that explains in detail and demonstrates why SCE's recorded adjusted expenses for 2005 through 2009 does not reflect the 2006 recorded expenses of $3.035 million (provided by SCE in its 2009 GRC) plus its 2009 additional authorized funding of $2.007 million for insulator washing.

SCE's response:

> The $3.035 million in 2006 recorded expenses provided in the 2009 GRC are in constant 2006$. The number was escalated to constant 2009$, to $3.354 million, in the 2012 GRC. The 2009 recorded expenses were less than what was authorized in the 2009 GRC because of various factors, including the retirement

[689] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 95.

[690] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 83.

[691] DRA-SCE-085-TLG question 10-b.

of older wash vehicles, (as discussed on page 95 of the testimony), higher rainfall amounts and less onshore flow, which reduced the need for insulator washing, and management discretion to use resources in other areas.

DRA asked:[692]

> In SCE's 2009 GRC, SCE requested $13.336 million for Poles and Structures recorded in Sub-Account 571.100. SCE was authorized approximately $10.264 million of its request. In SCE's 2009 GRC, SCE requested $16.643 million for Insulators and Conductors recorded in Sub-Account 571.200. SCE was authorized approximately $11.652 million of its request. SCE's 2009 authorized amounts totaled approximately $21.916 million to address its work activity for Poles and Structures and Insulators and Conductors. SCE's 2009 recorded adjusted expenses for its Transmission Maintenance expenses of $8.861 million (which includes work activities on transmission poles, transmission towers/structures, and transmission conductors) and its 2009 recorded adjusted expenses for Insulator Washing of $3.929 million together total $12.790 million.
>
> Provide the documentation that explains the discrepancy between the 2009 recorded adjusted expenses totaling $12.790 million for work activities on transmission poles, transmission towers/structures, transmission conductors, and insulator washing and SCE's 2009 authorized funding of approximately $21.916 million to address the above work activities. In the response be sure to address specifically where SCE diverted authorized funding of approximately $9.126 million.

SCE's response:

> As stated on page 11 of SCE-01, "The Commission expects SCE to manage its business between general rate case test years to optimize service to our customers and work toward realizing our authorized rate of return. In 2009, like nearly every other year, our recorded expenses varied from the specific categories authorized in the 2009 GRC decision".
>
> SCE does not specifically allocate or transfer authorized costs from one GRC sub-account to another. GRC authorized revenues are allocated through the SCE budgeting process.

SCE has embedded funding in its historical expenses to address its Insulator Washing activities. It is inappropriate to require increased ratepayer funding for activities that already have costs embedded in SCE's historical expenses; therefore no additional funding is required over SCE's 2009 recorded adjusted expenses of $3.709 million.

---

[692] DRA-SCE-085-TLG question 9.

DRA forecast $8.624 million for SCE's line item for Road and ROW Maintenance expenses utilizing a five year average (2005-2009) as a basis. SCE's expenses fluctuated significantly between 2005 and 2009 with an average for the five year period (2005-2009) of $8.624 million and a three year average (2007-2009) of $8.592 million. SCE's expenses declined between 2006 and 2008 by $2.971 million from $9.709 million in 2006 to $6.738 million in 2008. SCE's 2009 expenses increased by $4.056 million or 60.20% over 2008 recorded expenses of $6.738 million. SCE does not provide a detailed discussion in its testimony or data request responses on the specific cause of the increase between 2008 and 2009 of 60.20%.

SCE's Road and ROW Maintenance expense forecast is based on a five-year average (2005-2009) of its cost per line mile times the miles of overhead transmission lines.[693] SCE forecast adding additional line miles in 2010-2012. Based on SCE's recorded adjusted expenses, the amount of line miles in SCE's system does not appear to have caused major increases in historical expenses (2005-2009) recorded to Sub-Account 571.160. SCE states "In D.89-12-057, the CPUC stated that for those accounts which have significant fluctuations in recorded expenses from year to year, an average of recorded expenses is appropriate".[694] DRA recommends a five year average of $8.624 million as its test year forecast.

DRA forecast $9.929 million for SCE's line item for Capital-Related expenses utilizing SCE's last recorded year, the highest level of recorded expenditures, as a basis for its estimate. SCE's test year forecast of $14.235 million for its Capital-Related expenses is an increase of 43.37% over 2009 recorded adjusted expenses and is excessive. SCE's expenses increased by $9.101 million between 2005 and 2009 from $0.828 million in 2005 to $9.929 million in 2009. SCE's recorded adjusted expenses for its line item Capital-Related expenses averaged $3.891 million over the five year period (2005-2009) and averaged $5.724 million over the three year period (2007-2009). SCE states "Capital related expense can vary significantly based on the specific projects being implemented in a given year".[695] SCE's recorded expenses increased by $4.907 million or 97.71% between 2008 and 2009 from $5.022 million in 2008 to $9.929 million in 2009.

---

[693] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 97.

[694] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 97.

[695] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 99.

SCE utilized "a 2005 to 2009 weighted average ratio of 3.6 percent" to estimate future expenses. SCE states further "The 2010-2012 forecasts were calculated by multiplying this ratio and the forecast transmission capital expenditures that have a related expense component, for each year. The 2012 transmission capital expenditure total was normalized using 2012-2014 expenditures".[696] DRA requested additional information from SCE on its test year forecast. DRA asked:[697]

> SCE's non-labor expenses increased by $8.265 million between 2005 and 2009 from $0.534 million to $8.799 million. Provide the documentation that explains in detail and demonstrates why SCE's current funding level, which includes the increase of $8.265 million, is insufficient to address its work load in the test year in order to fully justify SCE's request for additional funding over 2009 recorded adjusted expenses of $3.816 million which is a 43.37% increase.

SCE's response:

> The 2009 recorded expenses are insufficient because SCE is forecasting a significant increase in the amount of capital work that leads to capital-related expenses. SCE used the five-year average of ratio of capital-related expenses to capital expenditures to forecast these expenses. The recorded 2009 capital expenditures totaled $570 million in 2009 and is forecast to increase to $1.304 billion in 2012. The 2012 transmission capital expenditure total was normalized using 2012-2014 expenditures. Page 41 of the workpapers contains the calculations for the capital-related expenses forecast.

DRA asked:[698]

> Provide the supporting documentation that shows the breakdown of the calculation of the $3.816 million increase in non-labor expenses and which demonstrates in detail the basis for each individual estimate included in the proposed increase of $3.816 million.

SCE's response:

> The increase in non-labor expenses between 2009 and 2012 is based entirely on the significant increase in capital work that creates capital-related expenses, such as major transmission line projects and deteriorated pole replacements, which increase the total forecast for capital-related expenses…

The Commission may not adopt SCE's proposed capital expenditures. DRA's test year estimates for several of SCE's proposed capital projects are lower than SCE's forecasts which

---

[696] Ex. SCE-3, Vol. 4, Part 8, Chapters I-II, page 99.

[697] DRA-SCE-085-TLG question 12-f.

[698] DRA-SCE-085-TLG question 12-h.

SCE utilized to forecast Sub-Account 571.160.[699] If DRA does not make a corresponding adjustment to the test year estimates proposed by SCE for this line item, the Capital-Related expenses will be significantly overfunded in the teat year.

SCE's method utilized to forecast its Capital-Related expenses is unnecessarily complicated and difficult to follow, and is based on significant capital increases in the test year. DRA's use of SCE's 2009 recorded adjusted expenses of $9.929 million, the highest level of expenditures for the five year period (2005-2009) as a basis is a reasonable test year method.

Capital Expenditures

For the Transmission Organization capital expenditures, SCE forecasts $34.1 million for 2010, $36.7 million for 2011 and $$36.7 million for 2012. DRA recommends the Commission adopt SCE's actual 2010 recorded amount of $34.3. DRA recommends $27.8 million in 2011 and again in 2012. The one area of dispute is the forecast for Transmission Deteriorated Poles.[700]

5.13.1. Transmission Deteriorated Poles

For Transmission Deteriorated Poles, SCE is forecasting $14.1 million in 2011 and $14.1 million in 2012. DRA recommends $5.2 million in 2011 and $5.2 million in 2012.

Between 1998 and 2007, SCE performed intrusive pole inspections in accordance with the first cycle of G.O. 165. This cycle required SCE to perform an intrusive pole inspection on all wood transmission and distribution poles over a ten year cycle. In the second cycle, 2008-2017, all wood distribution and transmission poles which are 25 years old are (installed before 1993) are required to have an intrusive pole inspection performed over the next 20 years, and all poles installed between 1993 and 2003, will need to have an intrusive pole inspection in the second cycle which will end in 2017.[701]

During the first cycle, SCE experienced a failure rate of 7.7% (for every 1,000 poles inspected, SCE needed to replace 77 poles).[702] SCE's experience during the second cycle is that

---

[699] The detailed discussion and analysis on SCE's proposed capital projects for the test year and DRA's corresponding estimates for SCE's capital projects will be addressed in Exhibits DRA-6 and DRA-7.

[700] It is DRA's understanding that SCE has corrected an error relating to Transmission Maintenance that appeared in SCE's original filing. Assuming SCE's 2009 constant dollar Transmission Maintenance projection is $5.6 million for 2010-2014, DRA does not dispute the forecast. (Ex. DRA-7, p. 62)

[701] General Order 165.

[702] Ex. DRA-7, p. 60, citing Response to DRA-SCE-198-MKB, Q. 2.

it is failing only 3.3% of the poles.[703] Besides the poles being replaced because they failed the intrusive inspection, SCE has also estimated a number of transmission poles being replaced because of district requests, and poles being replaced based on others.[704]

SCE's estimate differs from what is required by G.O. 165. DRA prepared its own estimate of the number of transmission wood poles that need to be replaced annually. DRA made its estimate by: (1) calculating the required G.O. 165 intrusive inspections and multiplying SCE's second cycle failure rate (217.8); (2) adding SCE's estimated 2010 district transmission wood pole replacement requests (52); (3) adding SCE's estimated 2010 other transmission wood pole replacement requests (23); and (4) multiplying the total transmission wood replacements (292.8) by SCE's 2009 average cost of installing a transmission wood pole ($17.59). This results in Transmission Deteriorated Pole costs in 2011 and 2012 of $ 5.2 million annually.

SCE's projections do not follow the intrusive inspection schedule set forth in G.O. 165. SCE's 2010-2014 projection results in 2,685 intrusive inspection replacements versus the G.O. 165 method of 1,089 (217.8 * 5) replacements. This results in SCE inflating its 5 year costs by $28 million.

DRA recommends the Commission adopt DRA's Transmission Deteriorated Pole cost of $5.2 million in 2011 & 2012 consistent with the Commission's G.O. 165 instructions.

5.14. T&D – Business Process and Technology Integration Operations and Maintenance Expenses -- 566.270 & 588.270

SCE forecast $20.217 million for its Business Process and Technology Integration (BP&TI) expenses and forecast O&M productivity benefits of $1.456 million.[705] The productivity benefits forecast of $1.456 million would reduce SCE's BP&TI forecast to $18.761 million in the test year. SCE developed its BP&TI forecast on a project-by-project basis and averaging its calculated expense estimates for 2012 through 2014 to forecast its 2012 expense levels. The corresponding DRA estimate for SCE's Business Process And Technology Integration expenses is $11.889 million, which is $6.872 million less than SCE's forecast.

---

[703] Ex. DRA-7, p. 60, citing Response to DRA-SCE-198-MKB, Q. 3.

[704] SCE Workpapers Transmission & Distribution, SCE-03, Volume 4, Part 8, Ch. II, page 157.

[705] Ex. SCE-3, Vol. 5, Part 1, Chapters I-III, page 54.

566.270 – TDBU Transmission Substation IT IMM

SCE forecast $7.844 million for Sub-Account 566.270 (Labor of $48,000 and Non-Labor of $7.796 million) for its TDBU Transmission Substation IT Interdepartmental Market Mechanism (IMM) expenses.[706] SCE's forecast of $7.844 million is an increase of $1.831 million or 30.45% over 2009 recorded adjusted expenses of $6.013 million.

SCE's expenses increased by $3.966 million between 2006 and 2009, with 2009 recording the highest level of expenditures of $6.013 million. SCE's recorded adjusted expenses averaged $3.690 million for the five year period (2005-2009) and averaged $4.412 million for the three year period (2007-2009). SCE's request for additional funding is not justified, and the method SCE utilized to calculated its forecasts for its Centralized Remedial Action Scheme program of $0.924 million and its Phasor Measurement and Wide Area Situational Awareness program of $0.907 million, based on calculated averages of its 2012 through 2014, expense forecasts[707] is not reasonable when compared to DRA's method, which utilizes SCE's recorded adjusted historical expenses. SCE has embedded funding in its historical expenses to address its test year projects associated with its Centralized Remedial Action Scheme program, Phasor Measurement and Wide Area Situational Awareness program, and its IT IMM expenses and additional funding is not required.[708] DRA requested additional information from SCE regarding its IT IMM O&M 2009 recorded adjusted expenses and its test year forecast.
DRA asked:[709]

> SCE forecast $6.013 million ($0.048 million for labor and $5.965 million for non-labor) for its IT IMM O&M expenses recorded in Sub-Account 566.270. In SCE's 2009 GRC SCE requested and was authorized $11.034 million for Sub-Account 566.300 (D.09-03-025 page 59-60). SCE's 2009 recorded adjusted expenses shown in Table II-19 on page 53 does not reflect SCE's 2009 authorized

---

[706] Ex. SCE-3, Vol. 5, Part 1, Chapters I-III, page 55.

[707] See pages 46 through 48 in Ex. SCE-03, Volume 5, Part 1, Chapters I-II.

[708] In SCE's response to DRA-SCE-113-TLG question 8, SCE provided a spreadsheet showing recorded adjusted expenses for 2005-2009 recorded in Sub-Accounts 566.270 and 588.270. In the response SCE does not show any recorded costs for the five year period for its Phasor Measurement and Wide Area Situational Awareness project even though SCE has been incurring associated costs for this project since 1997 (see page 47 in Ex. SCE-03, Volume 5 Part 1 Chapters I-III). SCE was also authorized funding for this project in its 2009 GRC (D.09-03-025, page 222). Similarly, SCE does not show any recorded expenses for its Centralized Remedial Action Scheme project, and SCE has been incurring associated expenses during the historical period, and this project was also authorized funding in its 2009 GRC (D.09-03-025, page 225).

[709] DRA-SCE-113-TLG question 14-a.

> amount. Provide the documentation that explains in detail and demonstrates where SCE diverted authorized funding that was requested to address work activities associated with IT IMM O&M expenses.

SCE's response:

> As stated on page 11 of SCE-01, "The Commission expects SCE to manage its business between general rate case test years to optimize service to customers and work towards realizing our authorized rate of return. In 2009, like nearly every other year, our recorded expenses varied from the specific categories authorized in the 2009 GRC decision". SCE does not specifically allocate or transfer authorized costs from one GRC sub-account to another. GRC authorized revenues are allocated through the SCE budgeting process.

SCE's response is incomplete, does not identify specifically where the requested and authorized embedded funding was allocated and recorded, and does not justify additional funding in the test year. DRA is troubled by SCE's apparent disregard for acknowledging the importance of its embedded costs included in its historical expenses associated with closed or completed projects that can be utilized for proposed projects and incorporated into its test year forecasts. DRA discovered the following when it asked for additional information from SCE on its BP&TI forecast.

DRA asked:[710]

> The increase in SCE's recorded adjusted expenses between 2008 and 2009 of $9.989 million or 98.98% associated with new projects and initiatives appear to be embedded in SCE's 2012 forecast of $20.217 million. DRA notes that SCE's recorded adjusted expenses decreased between 2005 and 2007 by $6.382 million due to completion of initiatives. The five year average (2005-2009) is $12.824 million and the three year average (2007-2009) is $12.848 million. Provide the documentation that explains in detail and demonstrates why SCE's 2012 forecast of $20.217 million ($60.651 million over the three year rate case cycle) does not reflect reductions to account for completion of projects and initiatives started in 2009.

SCE's response:

> SCE's forecast for BPTI O&M expenses does reflect reductions for completed programs and initiatives, simply due to the fact that SCE did not utilize any recorded project-specific expenses to develop its O&M forecasts...

[710] DRA-SCE-113-TLG question 8.

DRA asked:[711]

> SCE plans to continue to develop its phasor technology program. SCE began deploying phasor measurement capabilities in 1997. Activities planned for the current rate case include continued installations of higher-capability phasor measurement equipment and monitoring and control applications. Provide the documentation that explains in detail specifically why SCE's historical embedded expenses, which includes continued and on-going expenses associated with its phasor technology program, is insufficient to address on-going activities in the test year.

SCE's response:

> Please see SCE's response to DRA-SCE-113-TLG, Question 8 for a detailed description for how Sub-Account 566.270 was forecasts, including the Phasor Measurement project. The recorded expenses for specific projects and programs are not embedded in the forecast because SCE did not utilize any recorded project-specific expenses to develop its O&M forecasts.

DRA asked:[712]

> SCE states it "has recent experience in successfully managing large software projects with comparable scope, including the Graphical Design Tool and Click Software Scheduling projects". Provide the documentation that explains in detail and demonstrates why SCE is not able to allocate funds from projects that have been completed, closed, or are no longer being utilized to address its test year needs for activities associated with its Centralized Remedial Action Scheme and its Phasor Measurement and Wide Area Situational Awareness.

SCE's response:

> The Graphical Design Tool and the Click Software Scheduling project were adopted in the SCE's 2006 ratecase decision. Please see 1) Exhibit 84 at pages 57-58, and pages 50-51, 2) Exhibit 84 at pages 40-41, and 3) Exhibit 202 at page 16-19. As described in the testimony, the Business Process and Technology Integration (BPTI) group carries out assessments of work processes and information technology for the Transmission and Distribution Business Unit, identifies gaps, and coordinates and implements solutions, often in the form of large projects. As described in the testimony (see Figs II-8, 9 and 10) BPTI is forecasting test year expenses of $18.761 million, compared to recorded expense of $20.081 million in 2009.

---

[711] DRA-SCE-113-TLG question 15-a.

[712] DRA-SCE-113-TLG question 15b.

Although SCE had no difficulty incurring costs for special projects and programs, and calculating additional funding for test year initiatives, based on SCE's responses it has difficulty demonstrating why it is not able to allocate funds from projects that have been completed, closed, or are no longer being utilized to address its test year needs or with reflecting reductions to account for completion of projects and initiatives. SCE's 2009 recorded adjusted expenses of $6.013 million for Sub-Account 566.270, the highest recorded for the five year period (2005-2009) is a sufficient forecast for the test year.

588.270 – Technology Solution Implementation

SCE forecast $12.373 million for Sub-Account 588.270 (Labor of $2.684 million and Non-Labor of $9.689 million) for its Technology Solution Implementation expenses.[713] DRA utilized a five year average (2005-2009) as a basis for its forecast of $7.332 million for SCE's Sub-Account 588.270.

DRA made a normalized adjustment to SCE's recorded adjusted historical expenses (2005-2009) of $1.408 million recorded in Sub-Account 588.270 for ratemaking purposes. DRA's adjustment was made to remove discretionary costs associated with SCE's employee recognition program Spot Bonuses and Awards to Celebrate Excellence Recognition Points (ACE), which are inappropriate to charge to ratepayers.[714] SCE's employee recognition programs provide no clear or identifiable benefit to ratepayers and are not necessary to operate the utility business.

SCE's recorded expenses fluctuated significantly during the historical period and includes projects that have been completed, closed, or will no longer incur costs in the test year. DRA's use of a five year average is a reasonable method to account for the fluctuations. Because DRA utilized a five year average, DRA removed embedded costs of $6.2 million associated with SCE's special WISER project[715] from 2009 recorded adjusted expenses. SCE states that this project will be funded through its current rates and that "No additional O&M

[713] Ex. SCE-3, Vol. 5, Part 1, Chapters I-III, page 55.

[714] In SCE's response to DRA-SCE-113-TLG question 2 SCE provided spreadsheets, which included recorded adjusted expenses for 2005-2009 incurred for its employee recognition awards programs recorded to Sub-Account 560.220. DRA removed expenses totaling $1.408 million from its test year estimate which was based on a five year average.

[715] DRA provides further discussion on SCE's WISER project in its Exhibit DRA-22.

expenses have been forecast to support the WISER program beyond 2011".[716] DRA also removed one-time costs of $1.4 million from recorded adjusted 2009 expenses incurred for SCE's GIS Pilot project[717] because DRA considered this to be a special one-time non-recurring project. DRA also based its adjustment on SCE's statement that the GIS Pilot was a "landbase that was piloted was not placed into production and only resided in a test environment".[718]

The removal of costs incurred for SCE's special projects for its WISER and GIS Pilot projects, which were the main drivers of the $8.742 million increase in 2009 expenses over 2008 expenses of $5.326 million or a 164.14% increase, brings SCE's 2009 expense levels down to comparable levels with its 2007 and 2008 recorded expenses. DRA requested additional information from SCE regarding its 2009 recorded adjusted expenses and its test year forecast. DRA asked:[719]

> Provide the documentation that demonstrates in detail specifically how SCE incorporated the $8.742 million or 164.14% increase between 2008 and 2009 in to its test year forecast.

SCE's response:

> SCE did not incorporate the $8.742 million increase between 2008 and 2009 in its test year forecast. Please see SCE's response to DRA-SCE-113-TLG, Questions 8 for a detailed description of how Sub-Account 588.270 was forecast.

DRA asked:[720]

> In regards to SCE's GIS forecast of $6.277 million SCE states it "has experience in managing large comparable projects. Recent major successful projects include Graphical Design Tool and Click Software Scheduling project". Provide the documentation that explains in detail and demonstrates why SCE's embedded historical costs incurred for its recent completed major successful projects which included its Graphical Design Tool and Click Software Scheduling project cannot be allocated in the test year to address its GIS project.

SCE's response:

---

[716] Ex. SCE-3, Vol. 5, Part 1, Chapters I-II, page 44 and SCE's response to DRA-SCE-113-TLG question 7-d.

[717] DRA provides further discussion on SCE's GIS Pilot project in its Exhibit DRA-22.

[718] DRA-SCE-113-TLG question 12-i.

[719] DRA-SCE-113-TLG question 12-d.

[720] DRA-SCE-113-TLG question 12-h.

> Please see SCE's response to DRA-SCE-113-TLG, Question 8 for a detailed description for how Sub-Account 588.270 was forecast. The recorded expenses for specific projects and programs are not embedded in the forecast because SCE did not utilize any recorded project-specific expenses to develop its O&M forecasts.

SCE's request for additional funding is not justified and its method utilized to calculated its forecasts[721] for its Geographical Information System (GIS) project of $6.277 million, Consolidated Mobile Solutions (CMS) project of $0.755 million, Distribution Management System project of $0.702 million, and its Non-Capital projects of $3.5 million, based on calculated averages of its 2012 through 2014 expense forecasts,[722] are not reasonable when compared to DRA's method, which utilizes SCE's recorded adjusted historical expenses.[723] SCE has embedded funding in its historical expenses associated with these projects as well as several projects that have been completed or are nearing completion and the funding for those closed projects can be allocated towards test year projects.[724]

DRA's test year estimate of $11.889 million for SCE's Business Process And Technology Integration expenses is reasonable and consistent with recorded historical expenses.

5.15. T&D – Technical Services

Operations and Maintenance Expenses - 566.250, 582.250 & 588.250

SCE forecast $68.311 million for its Technical Services expenses. SCE developed its forecast by utilizing its 2009 recorded adjusted expenses for Sub-Accounts 566.250, 573.250, 582.250, 588.250, and 598.250, plus incremental expenses for proposed projects and work activities. The corresponding DRA estimate for SCE's Technical Services expenses is $57.379

---

[721] SCE's workpapers provided as support for its test year projects show spreadsheets with line items that have lump sum estimates for 2011 through 2014 that lack detailed background support for specifically how SCE calculated the individual numbers for the line items. The spreadsheets also lack recorded adjusted expenses for the projects that SCE incurred costs for during the historical period.

[722] See pages 19, 37, 45, and 50 in Ex. SCE-03, Volume 5, Part 1.

[723] In SCE's response to DRA-SCE-113-TLG question 7-d, SCE provided 2009 recorded expenses for its CMS project of $0.714 million, GIS of $3.938 million, and its WISER project of $6.213 million.

[724] In SCE's response to DRA-SCE-113-TLG question 7, SCE provided a spreadsheet showing its historical projects for 2005-2009 that have been completed or are nearing completion. In that same data response for question 8, SCE provided a spreadsheet showing recorded adjusted expenses for 2005-2009 recorded in Sub-Accounts 566.270 and 588.270 which shows recorded historical costs for SCE's GIS, CMS, DMS, WISER and Non-Capital projects.

million, which is $10.932 million less than SCE's forecast. DRA takes issue with SCE's test year forecasts for the Sub-Accounts that are discussed below.

566.250 – Safety and Training - Transmission

SCE forecast $20.712 million for Sub-Account 566.250 (Labor of $12.972 million and Non-Labor of $7.740 million) for its Safety and Training – Transmission expenses.[725] SCE's forecast of $20.712 million is an increase of $3.543 million or 20.64% over its 2009 recorded adjusted expenses of $17.169 million. SCE's Sub-Account 566.250 includes the following line items: Transmission Safety, Transmission Training Delivery, and TDBU Training Seat Time. DRA utilized SCE's last recorded year as a basis for its forecast of $17.038 million for SCE's Sub-Account 566.250.

SCE's expenses for the four line items recorded in Sub-Account 566.250 have fluctuated during the five year period (2005-2009). DRA analyzed the recorded adjusted expenses and the forecast estimates for each individual line item to calculate its test year estimates for Sub-Account 566.250.

DRA made a normalized adjustment to SCE's 2009 recorded adjusted historical expenses of $0.131 million recorded in Sub-Account 566.250 for ratemaking purposes.[726] DRA's adjustment was made to remove discretionary costs associated with SCE's employee recognition program (i.e. Spot Bonuses and Awards to Celebrate Excellence Recognition Points (ACE), etc.), which are inappropriate to charge to ratepayers. SCE's employee recognition programs provide no clear or identifiable benefit to ratepayers and are not necessary to operate the utility business.

DRA forecast $2.494 million[727] for SCE's line item for Transmission Safety expenses by utilizing SCE's last recorded year as a basis. SCE's Safety expenses recorded in Sub-Account 566.250 are incurred for its safety team meetings, trainings and programs, and safety development programs.[728] DRA requested additional information on SCE's historical expenses and its test year forecast.

---

[725] Ex. SCE-3, Vol. 5, Part 2, Chapters I-III, page 62.

[726] In SCE's response to DRA-SCE-066-TLG question 2-a, SCE provided costs incurred for employee recognition for 2005 through 2009.

[727] DRA made a normalized adjustment and removed $0.131 million associated with SCE's employee recognition awards from this line item for Sub-Account 566.250.

[728] Ex. SCE-3, Vol. 5, Part 2, Chapters I-III, page 19.

DRA asked:[729]

> Provide the documentation that demonstrates why SCE's increase of $3.553 million between 2005 and 2009, which is still embedded in SCE's recorded adjusted expenses, is insufficient to address its employee safety needs in the test year in order to justify an additional increase of $1.746 million.

SCE's response:

> On a per-employee basis, the costs embedded in this account are sufficient to address current employee safety needs. As indicated in the testimony, the forecast for this account is based upon 2009 recorded safety expenses per employee. The 2009 recorded safety expense per TDBU employee was $1,705. Since we forecast an increase of 1,024 in TDBU employees from 6,115 in 2009 to 7,139 in Test Year 2012 (see Figure II-2 in SCE-03, Volume 5, Part 2), we are forecasting a $1.746 million increase (1,024 * $1,705) in employee safety related expense. SCE is maintaining its 2009 cost per employee despite SCE's increasing focus on eliminating employee injuries. The increase between 2005 and 2009 is primarily attributed to implementation of ongoing programs targeted at reducing the number of employee injuries within TDBU.

DRA asked:[730]

> SCE states in its response to DRA-SCE-031-TLG questions 1-d that "SCE disagrees with this notion that an adopted level of funding means that a program must be executed, or that management loses discretion to reallocate funds to meet changing circumstances…" SCE's recorded adjusted 2009 expenses for its Transmission O&M expenses were $13 million less than authorized and its Distribution O&M expenses were $34 million less than authorized in its 2009 GRC. SCE's 2012 forecast for Sub-Account 566.250 and 588.250 include an additional $1.746 million over 2009 recorded expenses.
>
> Provide the documentation that explains in detail and demonstrates specifically why SCE is not able to reallocate funds to address its employee safety training needs in the test year.

SCE's response:

> Please refer to the response to DRA-SCE-031-TLG, question 1d, where a reference to SCE-1, pages 43-53 is provided. This section of testimony explains that SCE reallocates funds in response to changing circumstances. Funds are not reallocated between activities on a forecast basis. SCE has prepared a rate case forecast from the bottoms-up, meaning that our request is based on the amount of work that will need to be completed in 2012 and over the rate case cycle. Please also refer to SCE's response to DRA-SCE-

[729] DRA-SCE-066-TLG question 6-e.

[730] DRA-SCE-066-TLG question 5-a.

066-TLG, question 6e, where SCE explains that our request for additional funding for safety is based on additional employees that will require safety-related activities described on pages 3-23 of the testimony.

DRA asked:[731]

> SCE's recorded adjusted expenses for Safety increased by $1.700 million between 2008 and 2009 "due primarily to an increased emphasis of Therapeutic Exercise program" and "increased expenses associated with expanding the Safety Congresses to increase participations by middle-management employees…" Provide a detailed and itemized listing of all expenses incurred for SCE's increased emphasis of Therapeutic Exercise program" and "increased expenses associated with expanding the Safety Congresses" that specifically caused the $1.700 million increase, which is still embedded in SCE's test year forecast of $12.172 million.

SCE's response:

> Costs for individual programs are not tracked on a discrete basis. The costs are included in both Sub-accounts 566.250 and 588.250, along with the costs for other safety initiatives. Please see the attachment included in SCE's response to DRA-SCE-066-TLG, Question 6a. This document contains safety-related O&M expense by activity description for 2005-2009 by labor and non-labor expenses. An itemized list of all transactions is unduly burdensome and voluminous to provide in total, but the detailed records are available for review in SCE's General Office in Rosemead if DRA wishes to see these detailed records.

SCE's responses are incomplete and do not justify additional ratepayer funding in the test year over its 2009 expense levels. SCE has embedded costs in its historical expenses that can be utilized to address its Transmission Safety activities in the test year.[732] It is inappropriate to require increased ratepayer funding for activities that already have costs embedded in SCE's historical expenses. DRA's forecast of $2.494 million is a reasonable test year estimate for SCE to address its Transmission Safety activities in the test year.

---

[731] DRA-SCE-066-TLG question 6-d.

[732] DRA notes that SCE's request and authorized funding in its TY 2009 GRC was based on this similar argument (staff increases) as presented again in its TY 2012 GRC, however, SCE's 2009 recorded adjusted expenses recorded in Sub-Account 566.250 for Transmission Safety expenses is less than authorized. In SCE's TY 2009 GRC, the Company utilized Sub-Account 566.100 to record its Transmission Safety expenses (D.09-03-025 page 57 to 58). In its TY 2012 GRC, SCE records these expenses to Sub-Account 566.250.

DRA forecast $5.653 million for SCE's line item for Transmission Training Delivery expenses utilizing SCE's last recorded year, the highest recorded for the five year period (2005-2009), as a basis.[733] SCE's expenses increased by $3.643 million between 2005 and 2009 from $2.010 million in 2005 to $5.653 million in 2009. The average for the five year period (2005-2009) is $3.244 million. DRA forecast $8.891 million for SCE's line item for Transmission Training Seat Time expenses utilizing SCE's last recorded year as a basis.[734] The average for the five year period (2005-2009) is $8.505 million.

In SCE's TY 2009 GRC, SCE requested and was authorized $50.1 million for its Transmission and Distribution Training Delivery and Training Seat Time expenses.[735] In its testimony, DRA expressed concern over the level of funding SCE requested in its TY 2009 GRC for its training activities, which DRA believed were excessive based on SCE's 2006 recorded adjusted expenses. During its analysis of SCE's TY 2012 GRC, DRA discovered that SCE spent less than authorized in its 2009 GRC. SCE's 2009 recorded adjusted expenses are $39.329 million.[736]

The Commission stated the following in D.09-03-025, page 63:

> Although Edison's proposed increases are significant, we believe the various contributing factors Edison had identified provide solid grounds for approving the company's request. We disagree with DRA's argument that the request is excessive. We also disagree with DRA that the additional costs Edison identifies are embedded in historical expenses. Accordingly, we adopt Edison's forecast amount of $13.380 million for subaccount 566.700, and $31.632 million in expenses for subaccount 588.700.

SCE has embedded costs in its historical expenses that can be utilized to address its Transmission Training Delivery and Training Seat Time activities in the test year.[737] The

---

[733] Ex. SCE-3, Vol. 5, Part 2, Chapters I-III, page 46.

[734] Ex. SCE-3, Vol. 5, Part 2, Chapters I-III, page 50.

[735] D.09-03-025 page 63. In SCE's response to DRA-VERBAL-013, Q. 02, Supplemental, SCE provided its 2009 recorded adjusted expenses and its 2009 authorized amount of $50.107 million for Transmission and Distribution Training Delivery and Training Seat Time recorded to Sub-Accounts 566.250 and 588.250. In SCE's TY 2009 GRC SCE utilized Sub-Accounts 566.700 and 588.700 to record these expenses.

[736] Ex. SCE-03, Volume 5, Part 2, Chapters I-III, see page 43 for Transmission and Distribution Training Delivery 2009 expenses and page 48 for Transmission and Distribution Seat Time expenses.

[737] DRA notes that SCE is requesting funding for training activities in its TY 2012 GRC that it already requested and received funding for in its TY 2009 GRC. SCE should not charge ratepayers twice for the same programs and projects (DRA-SCE-066-TLG question 10-a).

Commission should reject increased ratepayer funding for activities that already have costs embedded in SCE's historical expenses. SCE's ratepayers should not be forced to fund SCE's excessive training costs in the test year, especially after a review and analysis of SCE's recorded adjusted expenses for 2005-2009, which clearly demonstrate that SCE requested more than was necessary in its TY 2009 GRC to address its training needs. DRA's forecast of $5.653 million for Transmission Training Delivery and $8.891 million for Transmission Seat Time expenses based on SCE's recorded 2009 expenses is a reasonable test year estimate.

582.250 – Environmental Safety

SCE forecast $2.926 million for Sub-Account 582.250 (Labor of $1.478 million and Non-Labor of $1.448 million) for its Environmental Safety expenses.[738] DRA utilized a four year average (2006-2009) as a basis for its forecast of $2.051 million for SCE's Sub-Account 582.250. DRA's estimate is $0.875 million less than SCE's forecast.

SCE's expenses increased by $1.722 million between 2005 and 2009, with 2009 recording the highest level of expenditures of $2.926 million. SCE's expenses fluctuated between 2005 and 2008 with an average for the four year period of $1.620 million. SCE's expenses increased by $0.810 million or by 38.28% between 2008 and 2009 from $2.116 million in 2008 to $2.926 million in 2009. SCE's labor expenses increase between 2007 and 2009 due to specific project work relating to an increased level of consultation, implementation of drinking water quality programs, increased water sampling and archaeological and biological activities.[739] DRA's forecast of $2.051 million based on a four year average (2006-2009) accounts for the "swings" and fluctuations in expenses recorded to Sub-Account 582.250 and is a reasonable test year method.

588.250 – Safety and Training - Distribution

SCE forecast $38.918 million for Sub-Account 588.250 (Labor of $25.470 million and Non-Labor of $13.448 million) for its Safety and Training – Distribution expenses.[740] SCE's forecast of $38.918 million is an increase of $6.332 million or 19.43% over its 2009 recorded adjusted expenses of $32.586 million.

---

[738] Ex. SCE-3, Vol. 5, Part 2, Chapters I-III, page 24.

[739] Ex. SCE-3, Vol. 5, Part 2, Chapters I-III, page 24 to 25.

[740] Ex. SCE-3, Vol. 5, Part 2, Chapters I-III, page 63.

SCE's expenses for the four line items recorded in Sub-Account 588.250 have fluctuated during the five year period (2005-2009). DRA analyzed the recorded adjusted expenses and the forecast estimates for each individual line item to calculate its test year estimates for Sub-Account 588.250.

DRA made a normalized adjustment to SCE's 2009 recorded adjusted expenses of $51,013 recorded in Sub-Account 588.250 for ratemaking purposes.[741] DRA's adjustment was made to remove discretionary costs associated with SCE's employee recognition program (i.e. Spot Bonuses and Awards to Celebrate Excellence Recognition Points (ACE), etc.), which are inappropriate to charge to ratepayers. SCE's employee recognition programs provide no clear or identifiable benefit to ratepayers and are not necessary to operate the utility business.

DRA forecast $7.750 million[742] for SCE's line item for Distribution Safety expenses by utilizing SCE's last recorded year, the highest recorded for the five year period (2005-2009) as a basis. The average for the five year period (2005-2009) is $6.308 million and the three year average (2007-2009) is $7.235 million. SCE's Safety expenses recorded in Sub-Account 588.250 are incurred for its safety team meetings, trainings and programs, and safety development programs.[743] DRA's estimate of $7.750 million utilizing SCE's 2009 expenses as a basis is more than SCE's five year and three year averages and is a reasonable test year estimate for SCE to address its safety activities in the test year.

DRA forecast $9.346 million for SCE's line item for Distribution Training Delivery expenses utilizing SCE's last recorded year as a basis.[744] SCE's expenses decreased by $4.517 million between 2006 and 2008 from $11.637 million in 2006 to $7.120 million in 2009. In 2009 SCE's expenses increased by $2.226 million over 2008 expenses. The decrease in expense was due in part to completion of several projects and training programs. DRA forecast $15.439 million for SCE's line item for Distribution Training Seat Time expenses utilizing SCE's last recorded year as a basis.[745] The average for the five year period (2005-2009) is $14.457 million,

---

[741] In SCE's response to DRA-SCE-066-TLG question 2-b, SCE provided costs incurred for employee recognition for 2005 through 2009.

[742] DRA made a normalized adjustment and removed $51,013 associated with SCE's employee recognition awards from this line item for Sub-Account 588.250.

[743] Ex. SCE-3, Vol. 5, Part 2, Chapters I-III, page 19.

[744] Ex. SCE-3, Vol. 5, Part 2, Chapters I-III, page 47.

[745] Ex. SCE-3, Vol. 5, Part 2, Chapters I-III, page 51.

and the three year average (2007-2009) is $15.408 million. DRA is concerned with SCE's proposed TDBU training activities and its test year forecast and requested additional information.

DRA asked:[746]

> Provide the documentation that explains in detail if SCE's expense forecast for various proposed TDBU projects and programs that DRA is currently reviewing and issuing discovery requests in order to make recommendations to the Commission for SCE's 2012 GRC, will be "executed" since SCE disagrees with this notion that an adopted level of funding means that a program must be executed.

SCE's response:

> Please refer to SCE's response to DRA-SCE-031-TLG, question 1d, where a reference to SCE-1, pages 43-53 is provided. This section of testimony explains that SCE relocates funds in response to changing circumstances. For instance, SCE has a forecast of the number of new service connections that will be needed for 2012 and the associated funding requirements (See SCE-03, Volume 4, Part 1). If fewer customers requested new service connections than forecast in 2012, SCE would reallocate the available funds to other necessary activities. SCE's request in the 2012 GRC is based on expected work volume, business conditions, and market expectations. SCE plans to execute according to this proposal if the entire request is authorized and if all the expected conditions that underlie these forecasts are realized.

As discussed in detail above in regards to SCE's Transmission Training activities recorded in Sub-Account 566.250, and based on SCE's response above, SCE has embedded costs in its historical expenses. SCE should have embedded costs because its "entire request" for training was authorized in its TY 2009 GRC, but due to "expected conditions" not being realized and programs not being "executed" as proposed in its TY 2009 GRC, there is embedded funding that can be "reallocated" to address its Distribution Training activities recorded in Sub-Account 588.250.[747] The Commission should reject increased ratepayer funding for activities that already have costs embedded in SCE's historical expenses.[748]

---

[746] DRA-SCE-066-TLG question 5-d.

[747] DRA notes that SCE is requesting funding for training activities in its TY 2012 GRC that it already requested and received funding for in its TY 2009 GRC. SCE should not charge ratepayers twice for the same programs and projects (DRA-SCE-066-TLG question 10-a).

[748] SCE was authorized $579 million in its TY 2009 GRC for TDBU. SCE's recorded adjusted expenses for 2009 of $531 million was $48 million less than authorized (Ex. SCE-03, Volume 1, Chapters I-VI, page 20).

5.16. T&D – Business, Regulatory and Financial Planning Operations and Maintenance Expenses - 566.280 & 588.280

SCE forecast $13.271 million for its Business, Regulatory and Financial Planning expenses.[749] SCE developed its test year forecast by utilizing its 2009 record adjusted expenses for Sub-Accounts 566.280, 580.280 and 588.280 plus incremental expenses for proposed projects and work activities. The corresponding DRA estimate for SCE's Business, Regulatory And Financial Planning expenses is $7.064 million, which is $6.207 million less than SCE's forecast.

566-280 – Compliance, Policy, Contracts, and Billing[750]

SCE forecast $11.626 million for Sub-Account 566.280 (Labor of $8.910 million and Non-Labor of $2.716 million) for its Compliance, Policy, Contracts and Billing expenses.[751] SCE's forecast of $11.626 million is an increase of $5.744 million or 97.65% over 2009 recorded adjusted expenses of $5.882 million. DRA utilized SCE's last recorded year as a basis for its forecast of $5.882 million for SCE's Sub-Account 566.280.

SCE's request is excessive when compared to its recent historical expense levels. SCE's expenses fluctuated between 2005 and 2009, with an average for the five year period (2005-2009) of $5.304 million and a three year average (2007-2009) of $4.692 million.

SCE claims that its labor increase of $4.104 million or 85.39% over 2009 recorded labor of $4.806 million in Sub-Account 566.280 is due to interconnection requests relating to renewable generation projects. SCE has not provided sufficient documentation to support an increase of 85.39% in the test year.[752] SCE did not provide documentation demonstrating that its current staffing level was insufficient to address test year activities but provided a count of additional employees and unsupported costs calculations. SCE did not provide a cost benefit analysis, but provided a brief description of activities for various areas which does not demonstrate that its current staffing level is insufficient to address the work. The activities appear to be on-going and routine in nature and SCE should have embedded funding for similar

---

[749] Ex. SCE-3, Vol. 5, Part 3, Chapters I-III, page 4.

[750] See Section 5.18 for a contintued discussion of NERC CIP costs and the reasons why these costs should not be approved in this rate case.

[751] Ex. SCE-3, Vol. 5, Part 3, Chapters I-III, page 11.

[752] Ex. SCE-3, Vol. 5, Part 3, Chapters I-III, page 8-9.

activities that it can utilize to address its test year activities.[753] DRA asked for additional information on SCE's test year increases.

DRA asked:[754]

> SCE forecast $11.626 million in the test year for Sub-Account 566.280 which is included in the forecast of $13.271 million, and is an increase of $5.744 million or 97.65% over 2009 recorded adjusted expenses. SCE's labor expenses increased by $1.197 million or 33.17% between 2008 and 2009 from $3.609 million in 2008 to $4.806 million in 2009. SCE forecast $8.910 million for labor in 2012, which is an increase of $4.104 million or 85.39% over recorded adjusted 2009 labor expenses of $4.806 million.
>
> Provide the cost benefit analysis prepared prior to this data request, that SCE's management relied upon to determine that its labor expenses needed to increase by an additional 85.39% (for thirty three additional positions) over 2009 recorded adjusted expenses.

SCE's response:

> An assessment was performed for each group in Sub-Account 566.280 of the staffing needed to perform the work in Test Year 2012. These needs are detailed in the testimony for this exhibit. Further, the costs associated for the needed staffing levels were calculated as an increment to the 2009 base year. A separate cost benefit analysis was not performed.

DRA asked:[755]

> SCE forecast $2.716 million in non-labor expenses for Sub-Account 566.280, this is an increase of $1.640 million or 152.42% over 2009 recorded adjusted expense of $1.076 million. SCE's non-labor recorded adjusted expenses have fluctuated significantly over the five year period (2005-2009). SCE states that the $1.640 million "is needed primarily for the NERC Critical Infrastructure Protection Reliability Standards".
>
> Provide the documentation that explains in detail and demonstrates if this is the first time ever, the 2012 GRC that SCE has had to address NERC Critical Infrastructure Protection Reliability Standards, if not, state how SCE has

---

[753] DRA has concerns that SCE is making duplicate test year requests for similar activities for funding in Sub-Account 566.280 and other areas in the test year which is inappropriate and a burden to ratepayers. DRA discovered that SCE's Electric System Planning Group (SCE-03, Volume 3, Part 1, Chapters I-II) is performing very similar activities relating to interconnection requests and NERC standards (SCE also refers DRA to its data responses for that area: Sub-Accounts 561.210 and 587.210). Based on this DRA believes that SCE should have sufficient funding embedded in its historical expenses for these activities.

[754] DRA-SCE-221-TLG question 7-c.

[755] DRA-SCE-221-TLG question 8-b.

addressed this work and provide all associated costs.

SCE's response:

Please refer to the response to question 8.b) of data request DRA-TLG-218.

DRA asked:[756]

Provide the documentation that explains in detail and demonstrates if SCE incurred development and implementation costs associated with NERC Reliability Standards during 2005-2009, if so provide the Sub-Accounts and the associated cost for each year and state how those embedded costs were incorporated into the test year forecast

SCE's response:

Please refer to the response to question 8.b) of data request DRA-TLG-218.

DRA asked:[757]

Provide the documentation that explains in detail and demonstrates why SCE's current staffing level, which includes an increase of $1.197 million or an increase of 33.17% over 2008 expenses are insufficient to address its test year needs.

SCE's response:

The current staffing level is not sufficient to perform the additional work described in the testimony for the exhibit.

DRA asked:[758]

Provide all T&D O&M expense Sub-Accounts where SCE is requesting funding to address NERC Reliability Standards and the total amount requested in each Sub-Account.

SCE's response:

[756] DRA-SCE-221-TLG question 8-f.

[757] DRA-SCE-221-TLG question 7-d.

[758] DRA-SCE-218-TLG question 8-b. Note that, instead of providing the requested information relating to specific questions on the forecast estimate for Sub-Account 566.280, SCE refers DRA to this response which relates to Sub-Account 561.210 and 587.210 for its Electric System Planning. DRA believes SCE is making duplicate test year requests for the same or very similar activities and this is a burden to ratepayers.

> Please refer to the response to Question 4 of DRA-Verbal-052. As described in that presentation, NERC reliability standards affect almost the entire company. Since NERC standards and requirements are reflected in new facilities, equipment, and operating systems, the costs of meeting NERC reliability standards are reflected in capital, as well as O&M costs. Because the NERC standards have been in effect for an extensive period of time, the costs of meeting current and upcoming standards is reflected in on-going operations as well as the GRC forecast, and cannot be isolated from other costs. Please also refer to the response to Question 3, of DRA-Verbal-052, where SCE has provided the incremental costs of meeting NERC CIP requirements for 2012 Test Year.

DRA learned in a meeting on February 10, 2011 between DRA and SCE that SCE has embedded costs in its historical expenses for these activities due to the fact that SCE has been performing activities associated with NERC CIP requirements and revised standards for several years.[759] DRA also learned in that meeting that SCE has not specifically tracked all the related costs that are embedded in its TDBU historical expenses, and therefore is not able to accurately calculate expense increases to justify additional funding. The Commission should reject SCE's request for additional ratepayer funding, claiming that the expenses are increasing, when it is not able to properly track and calculate historical expenses associated with this activity.

SCE's responses are insufficient and the support the Company provided is lacking and does not justify additional funding of 97.64% over its 2009 recorded adjusted labor expenses. SCE has embedded funding in its historical expenses for on-going activities and from completed projects that can be utilized for test year activities and no additional funding is required. DRA's test year estimate of $5.882 million, based on SCE's 2009 recorded adjusted expenses, and is more than SCE's five year and three year averages and is a reasonable test year forecast.

588.280 – Distribution Construction Contract Management

SCE forecast $1.423 million for Sub-Account 588.280 (Labor of $1.193 million and Non-Labor of $0.230 million) for its Distribution Construction Contract Management expenses.[760] SCE's forecast of $1.423 million is an increase of $0.263 million or 22.67% over 2009 recorded adjusted expenses of $1.160 million. DRA utilized SCE's last recorded year as a basis for its forecast of $0.962 million for SCE's Sub-Account 588.280.

---

[759] SCE has embedded funding for this project and an example of SCE requesting funding in its 2009 GRC to address its NERC Critical Infrastructure project activities is shown in D.09-03-025 page 234.

[760] Ex. SCE-03, Volume 5, Part 3, Chapters I-III, page 55.

DRA made a normalized adjustment to SCE's 2009 recorded adjusted expenses for Sub-Account 588.280 to remove $198,000[761] for ratemaking purposes. DRA's adjustment was made to remove discretionary costs associated with SCE's employee recognition program (i.e., Spot Bonuses and Awards to Celebrate Excellence Recognition Points (ACE), etc.), which are inappropriate to charge to ratepayers. SCE's employee recognition programs provide no clear or identifiable benefit to ratepayers and are not necessary to operate the utility business.

SCE's request for an increase of 22.67% over 2009 recorded adjusted expenses is not justified. SCE's expenses remained relatively stable between 2005 and 2009 with an average for the five year period (2005-2009) of $1.108 million and a three year average (2007-2009) of $1.161 million. SCE's request includes funding for its employee recognition program, which is discussed above, and additional funding for software upgrades. SCE should have embedded costs for software upgrades from programs that are no longer in use or are no longer incurring maintenance costs and from embedded costs incurred for purchases of software programs during the last five years (2005-2009). DRA's estimate of $0.962 million is a reasonable test year estimate.

5.17. T&D – Other Costs and OOR

Operations and Maintenance Expenses

5.17.1. Other Costs - 560.281, 568.281, 588.281, 580.282 & 590.281

SCE forecast $108.509 million for its TDBU Other Costs.[762] SCE developed its forecast by utilizing its 2009 recorded adjusted expenses for Sub-Accounts 560.281, 566.281, 569.281, 568.281, 570.281, 583.281, 584.281, 586.281, 588.281, 590.281, 566.282, and 580.282 plus incremental expenses for proposed projects and work activities. The corresponding DRA estimate for SCE's TDBU Other Costs is $93.267 million, which is $15.242 million less than SCE's forecast. DRA takes issue with SCE's test year forecasts for the Sub-Accounts that are discussed below.

560.281 – Transmission Work-Order Write-offs

SCE forecast $3.962 million for Sub-Account 560.281 (Labor of $0.277 million and Non-Labor of $3.685 million) for its Transmission Work-Order Write-offs.[763] SCE's forecast is

[761] Ex. SCE-3, Vol. 5, Part 3, Chapters I-III, page 17 and DRA-SCE-221-TLG question 9-b.

[762] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, Page 27.

[763] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 30.

based "on the average historical percentage (2005 through 2009) of write-offs to transmission capital expenditures, multiplied by the forecast capital expenditures for transmission interconnection projects and transmission substation planning projects".[764] DRA utilized a five year average (2005-2009) as a basis for its forecast of $1.589 million for SCE's Sub-Account 560.261. DRA's estimate is $2.403 million less than SCE's forecast.

SCE's Write-offs are associated with SCE's "cancelled capital projects, unpaid claims for damaged facilities, and uncollected costs for billable work orders".[765] SCE's expenses fluctuated between 2005 and 2009 with an average for the five year period (2005-2009) of $1.559 million. The large increases in expenses that occurred in 2009 were due to SCE's "cancellation of the Ultra Small Antenna Terminal Satellite System project".[766]

SCE's method utilized to forecast its test year expenses for Sub-Account 560.281 is unnecessarily complicated and difficult to follow, and is also problematic because it is based on significant capital increases in the test year. SCE's proposed capital may not be adopted as forecast by SCE and DRA has made adjustments to SCE's capital forecast that is lower than SCE's estimates.[767] If DRA does not make a corresponding adjustment to the test year estimates proposed by SCE for Sub-Account 560.281 SCE's expenses recorded to this Sub-Account will be significantly overfunded in the test year. DRA's estimate of $1.559 million for Sub-Account 560.281, based on a five year average (2005-2009) of recorded expenses in this Sub-Account, addresses the fluctuations during the historical period and is a reasonable test year estimate.[768]

588.281 – Underground Locate Payment and Work-Order Write-offs

SCE forecast $20.614 million for its Sub-Account 588.281 Underground Locate Payment and Work-Order Write-offs (Labor of $0.613 million and Non-Labor of $20.001 million). SCE's Sub-Account 588.281 includes the following line items: Distribution Work Order Write-offs and Underground Utility Locating Service. DRA utilized a three year and a five year average as a basis for its forecast of $17.195 million for SCE's Sub-Account 588.281.

---

[764] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 29.

[765] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 28.

[766] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 28.

[767] The detailed discussion and analysis of SCE's proposed capital projects for the test year and DRA's corresponding estimates for SCE's capital projects will be addressed in Exhibits DRA-6 and DRA-7.

[768] DRA provides further discussion regarding adjustments relating to Sub-Account 560.281 in its Exhibit DRA-22.

SCE forecasts $10.427 million for its line item for Distribution Work-Order Write-offs.[769] SCE's forecast is "based on the average historical percentage (2005 through 2009) of write-offs to distribution capital expenditures, multiplied by the forecast capital expenditures for Distribution work".[770] DRA utilized a five year average (2005-2009) as a basis for its forecast of $8.214 million for this line item recorded to SCE's Sub-Account 588.261. DRA's estimate is $2.213 million less than SCE's forecast.

SCE's Distribution Work-Order Write-offs are associated with SCE's "cancelled capital projects, unpaid claims for damaged facilities, and uncollected costs for billable work orders".[771] SCE's expenses fluctuated between 2005 and 2008 with an average for the four year period (2005-2008) of $6.528 million. SCE's expenses increased significantly in 2009 by $13.363 million or by 263% over 2008 recorded expenses of $5.081 million. The increase in expenses that occurred in 2009 was due in part to SCE's write-off for the Catalina Island fire.[772] DRA removed $3.484 million[773] associated with the unusual and non-recurring Catalina Island fire from its estimate for SCE's Sub-Account 588.281. DRA considers the significant damage resulting from the fire to be extraordinary, infrequent and unpredictable event within the term of a rate case cycle.[774]

The method SCE utilized to forecast its test year expenses for Sub-Account 588.281 is unnecessarily complicated and difficult to follow, and is also problematic because it is based on significant capital increases in the test year. The Commission may not adopt SCE's proposed capital and DRA has recommended adjustments to SCE's capital forecast.[775] If DRA does not make a corresponding adjustment to the test year estimates proposed by SCE for Sub-Account 588.281 SCE's expenses recorded to this Sub-Account will be significantly overfunded in the test year. DRA's estimate of $8.214 million for this line item, based on a five year average

---

[769] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 32.

[770] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 31.

[771] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 28.

[772] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 33.

[773] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 33. SCE did not remove the one-time costs associated with the Catalina Island fire (DRA-SCE-221-TLG question 11).

[774] DRA provides further discussion on SCE's Catalina Island fire in Exhibit DRA-22.

[775] The detailed discussion and analysis on SCE's proposed capital projects for the test year and DRA's corresponding estimates for SCE's capital projects will be addressed in Exhibits DRA-6 and DRA-7.

(2005-2009) of recorded expenses in this Sub-Account, addresses the fluctuations during the historical period and is a reasonable test year estimate.[776]

SCE forecasts $10.187 million for its line item for Underground Utility Locating Service. SCE utilized its last recorded year as a basis for its forecast.[777] DRA utilized a three year average (2007-2009) as a basis for its forecast of $8.981 million for this line item recorded to Sub-Account 588.261.

SCE's expenses fluctuated between 2005 and 2007 and then remained relatively stable between 2007 and 2008. The average for the five year period (2005-2009) is $8.235 million. SCE's expenses increased by $1.901 million in 2009 over 2008 expense levels. DRA utilized a three year average (2007-2009) because it reflects the most recent activity in this line item and addresses the increase in expenses in 2009, after recorded expenses were relatively stable for two years (2007-2008) prior to the $1.9 million increase in 2009. DRA's estimate of $8.981 million for Sub-Account 588.281, based on a three year average (2007-2009) of recorded expenses in this Sub-Account is a reasonable test year estimate.

580.282 – Facility Maintenance - Distribution

SCE forecast $9.066 million for its Sub-Account 580.282 Facility Maintenance – Distribution expenses (Labor of $0.063 million and Non-Labor of $9.003 million). DRA utilized a five year (2005-2009) as a basis for its forecast of $5.918 million for SCE's Sub-Account 580.282.

SCE's recorded adjusted expenses were relatively stable between 2005 and 2007 with an average for the three year period (2005-2007) of $3.916 million.[778] In 2008, the expenses increased by $4.767 million or 118.23% over 2007 recorded expenses of $4.032 million. SCE states "Prior to 2008, the cost recorded to this account included only TDBU's portion of facility maintenance. Beginning in 2008, this account included all facility maintenance (TDBU plus

---

[776] DRA provides further discussion regarding adjustments relating to Sub-Account 588.281 in Exhibit DRA-22.

[777] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 34.

[778] SCE provided an estimate of the facility maintenance expenses for Distribution only, for 2008 and 2009. The estimates are $3.215 million for 2008 and $2.893 million for 2009 (DRA-SCE-221-TLG question 13-d). Based on SCE's response, DRA clacuates the five year average (2005-2009) for SCE's facility maintenance expenses for Distribution only as $3.571 million, which is less than DRA's forecast of $5.918 million for Sub-Account 580.282.

other business units)".[779] SCE states further that it "combined all costs for distribution facility maintenance in sub-account 580.282 for ease and transparency in presenting the costs. The cost was presented in the TDBU testimony because TDBU is the largest user of distribution facilities".[780]

DRA is concerned that SCE may be requesting duplicate ratepayer funding in varies business units for facility maintenance expenses, in addition to its request in Sub-Account 580.282 for Distribution facility maintenance, since SCE combined all costs for distribution facility maintenance in sub-account 580.282 for ease and transparency in presenting the costs. SCE did not provide the historical expenses for 2005 through 2009 and the test year forecasts for the business units that now have costs combined in Sub-Account 580.282. DRA could not completely review and analyze all facility maintenance expenses to determine whether or not SCE's test year forecast has duplicate requests for facility maintenance.[781] The Commission should reject SCE's request to increase ratepayer funding for the same activities. DRA's estimate of $5.918 million utilizing a five year average (2005-2009) addresses its concern as well as the fluctuations in recorded expenses.

568.281 – Transmission Allocated Costs

SCE forecast $14.378 million for Sub-Account 568.281 (Labor of $4.618 million and Non-Labor of $9.752 million) for its Transmission Allocated Costs.[782] SCE's forecast of $14.378 million is an increase of $2.393 million or 19.98% over 2009 recorded adjusted expenses of $11.977 million. DRA utilized SCE's last recorded year, the highest recorded expenditures for the five year period (2005-2009), as a basis for its forecast of $11.977 million for SCE's Sub-Account 568.281.

---

[779] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 37.

[780] DRA-SCE-221-TLG question 13-a.

[781] SCE did not provide the information DRA requested on the historical facility maintenance expenses for the other business units for review and analysis (DRA-SCE-221-TLG question 13-b).

[782] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 44.

SCE's forecast is based on significant increases in its proposed capital in the test year.[783] DRA's test year estimates for several of SCE's proposed capital projects[784] are lower than SCE's forecasts, which it utilized to forecast its Sub-Account 568.281 expenses. If DRA does not make a corresponding adjustment to SCE's forecast for Sub-Account 568.281 the expenses recorded to Sub-Account 568.281 would be overfunded in the test year.[785] DRA's test year estimate of $11.977 million based on SCE's 2009 recorded expenses, which is more than the five year average of $9.919 million and the three year average of $10.711 million, is a reasonable test year estimate and is comparable to its recent historical expense levels recorded in Sub-Account 568.281.

590.281 – Distribution Allocated Costs

SCE forecast $45.453 million for Sub-Account 590.281 (Labor of $16.575 million and Non-Labor of $28.278 million) for its Distribution Allocated Costs.[786] SCE's forecast of $14.378 million is an increase of $3.946 million or 9.51% over 2009 recorded adjusted expenses of $41.507 million. DRA utilized SCE's last recorded year, the highest recorded expenditures for the five year period (2005-2009) as a basis for its forecast of $41.507 million for SCE's Sub-Account 590.281. SCE's recorded adjusted expenses fluctuated during the five year period (2005-2009) with an average for the five year period of $33.707 million and a three year average (2007-2009) of $35.490 million. SCE states "We took all projected capital, O&M, and allocated costs throughout TDBU, and using the spreadsheet described in Section II.B, calculated the amount that should be allocated to this account".[787]

---

[783] SCE created an allocation spreadsheet that is supposed to address the concerns of using its proposed capital to forecast its expense levels in Sub-Account 568.281. In regards to its spreadsheet SCE states "The spreadsheet described above is available upon request. Changes to direct expenses can be input to determine the effect on the distribution cost centers. The spreadsheet does not perform these calculations for changes in capital. The capital exhibits include support costs in their forecasts (Ex. SCE-03, Volume 5, Part 4, Chapters I-III, page 52).

[784] The detailed discussion and analysis on SCE's proposed capital projects for the test year and DRA's corresponding estimates for SCE's capital projects will be addressed in Exhibits DRA-6 and DRA-7.

[785] In SCE's TY 2009 GRC, SCE was authorized less than it forecast for its Transmission and Distribution allocated costs due to SCE utilizing its proposed capital and TDBU O&M expenses as the basis for its forecast for this Sub-Account. Note that in SCE's 2009 GRC it utilized Sub-Accounts 560.280, 568.280, 580.980, and 590.980 to record its allocated costs. For its 2012 GRC SCE utilizes Sub-Accounts 568.281 and 590.281 to record its allocated costs (D.09-03-025 page 49 to 51).

[786] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 45.

[787] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 45.

As mentioned above in the discussion on SCE's Sub-Account 568.281 for its Transmission Allocated Costs, SCE's forecast is based on significant increases in its proposed capital in the test year. DRA's test year estimates for several of SCE's proposed capital projects[788] are lower than SCE's forecasts which it utilized to forecast its Sub-Account 590.281. If DRA does not make a corresponding adjustment to SCE's forecast for Sub-Account 590.281 the expenses recorded to Sub-Account 590.281 would be overfunded in the test year.[789] DRA's test year estimate of $41.507 million based on SCE's 2009 recorded expenses, which is more than the five year average of $33.707 million and the three year average of $35.490 million, is a reasonable test year estimate for SCE to address its test year activities recorded to Sub-Account 590.281.

5.17.2. OTHER OPERATING REVENUES 451.100 & 456.308

SCE forecast $110.441 million for its TDBU Tariffed Other Operating Revenue (OOR) for TY 2012.[790] SCE's TDBU receives OOR for various activities and transactions that are not associated with its sale of electric energy. SCE's OOR is supposed to offset its revenue requirement. SCE's Tariffed OOR is based on the CPUC or FERC approved rates. The Corresponding DRA estimate for SCE's OOR is $111.571 million, which is $1.130 million more than SCE's forecast.

Overview of SCE's Request

SCE developed its OOR forecast of $110.441 million by utilizing the separately calculated forecasts for Sub-Accounts 451.100, 451.500, 454.300, 454.350, 454.500, 456.300, 456.306, 456.307, 456.308, 456.340, 456.319, 456.320, 456.323, 456.700, and 456.900. DRA takes issue with SCE's test year forecasts for the Sub-Accounts that are discussed below.

---

[788] The detailed discussion and analysis on SCE's proposed capital projects for the test year and DRA's corresponding estimates for SCE's capital projects will be addressed in Exhibits DRA-6 and DRA-7.

[789] In SCE's TY 2009 GRC, SCE was authorized less than it forecast for its Transmission and Distribution allocated costs due to SCE utilizing its proposed capital and TDBU O&M expenses as the basis for its forecast for this Sub-Account. Note that in SCE's TY 2009 GRC it utilized Sub-Accounts 560.280, 568.280, 580.980, and 590.980 to record its allocated costs. For its TY 2012 GRC SCE utilizes Sub-Accounts 568.281 and 590.281 to record its allocated costs (D.09-03-025 page 49 to 51).

[790] Ex. SCE-03, Volume 5, Part 4, Chapters I-III, page 58.

Meter Damage and Temporary Services

SCE forecast $26,000 for Sub-Account 451.100 for its Meter Damage and Temporary Services.[791] SCE calculated its forecast by escalating "the recorded 2009 revenue to years 2012-2014 and averaged the result for Test Year 2012".[792] DRA utilized a five year average (2005-2009) as a basis for its forecast of $1.134 million for SCE's Sub-Account 451.100.

SCE's revenues recorded in Sub-Account 451.100 increased each year between 2005 and 2007 from $1.022 million in 2005 to $1.938 million in 2007. In 2008 SCE's recorded revenues shown in this Sub-Account decreased to $0.517 million in 2008 and declined further in 2009 to $24,000. The decline in recorded revenues in this Sub-Account is due mostly to SCE's implementation of its SAP system in 2008. SCE states "Prior to SAP, customer payments for temporary services were recorded to this revenue account while expenses were recorded to an expense account. With implementation of SAP, payments received for temporary services are recorded to the same account in which we record the expense".[793]

DRA is concerned with the accurate tracking and recording of revenues and expenses, and SCE's method of now combining recorded expenses and revenues in the same account. SCE did not provide the Sub-Account that showed the historical data on its expenses, prior to the implementation of its SAP system in 2008 for review, analysis, and comparison to the data recorded in Sub-Account 451.100 in order to determine the reasonableness of SCE's test year forecast. SCE states the "change in accounting results in a reduction in the revenue recorded to this account; however, it matches the customer payments and installation costs in the same accounting location and therefore has no net effect on the revenue requirement".[794] SCE has provided insufficient documentation to determine that its change in accounting "therefore has no net effect on the revenue requirement".

It is not clear from SCE's testimony and workpapers if SCE is requesting ratepayer funding in its TY 2012 GRC for the associated expenses that were recorded in an expense account prior to its SAP implementation which caused SCE to combine its expenses and revenues in Sub-Account 451.100. Based on its concern, DRA utilized a five year average

---

[791] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 61.

[792] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 60.

[793] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 60.

[794] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 60.

(2005-2009) of SCE's recorded revenues in this Sub-Account as a basis for its estimate of $1.134 million for Sub-Account 451.100.[795]

Transmission Services for Generation and Non-ISO Services

SCE forecast $1.150 million for Sub-Accounts 456.308 and 456.340 for its Transmission Services for Generation and NON-ISO Services.[796] SCE calculated its forecast by escalating "the recorded 2009 revenue to years 2012-2014 and averaged the result for Test Year 2012".[797] DRA utilized a five year average (2005-2009) as a basis for its forecast of $1.172 million for SCE's Sub-Accounts 456.308 and 456.340.

SCE's revenues recorded in Sub-Accounts 456.308 and 456.340 remained relatively stable between 2005 and 2009. SCE states "From 2005-2009, the revenue remained relatively flat with one exception. In 2008, the revenue temporarily decreased by $242,000 due primarily to a refund to Southern California Water Company for a billing issue from the previous year".[798]

DRA's estimate of $1.172 million for SCE's Sub-Accounts 456.308 and 456.340, based on a five year average of SCE's recorded revenues, is a reasonable method and is comparable to SCE's historical levels.[799]

5.18. T & D -- NERC/CIP-Related Costs

Not only is SCE improperly requesting funding in this rate case for NERC Critical Infrastructure Project (CIP) compliance costs, SCE has improperly collected these costs in at least one prior rate case cycle (SCE's 2009 GRC), thus improperly embedding NERC CIP costs in SCE's historical costs.[800] Below, DRA will demonstrate that, at the very least, SCE has failed to meet its burden to show that NERC CIP compliance costs are, and have been, appropriately

---

[795] SCE utilized a Distribution composite escalation rate of 1.0713 to calculate its forecast of $26,000 for Sub-Account 451.100. SCE's escalation rate is comparable to the escalation rate DRA calculated of 1.0717 and both rates result in a forecast estimate of $1.134 million utilizing a five year average (2005-2009) of recorded revenue.

[796] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 73.

[797] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 72.

[798] Ex. SCE-3, Vol. 5, Part 4, Chapters I-III, page 72.

[799] SCE utilized a Transmission composite escalation rate of 1.0731 to calculate its forecast of $1.150 million for Sub-Accounts 456.308 and 456.340. DRA utilized SCE's escalation rate to calculate its estimate of $1.172 million utilizing a five year average (2005-2009) of SCE's recorded revenue.

[800] As will be discussed in more detail, SCE admitted that it had embedded NERC CIP compliance costs in rates. See, 10 RT 1137:22-25, Reeves/SCE.

recorded. At the worst, SCE has knowingly requested these costs, in the past and in this 2012 case, in order to over-collect from both FERC jurisdictional ratepayers and from CPUC jurisdictional ratepayers.[801]

If SCE has been improperly recording, and double collecting in rates costs associated with NERC CIP compliance, SCE's Results of Operations (R/O) model will allocate the wrong percentage to Account 566 (and other accounts too, in all likelihood). The result is that CPUC jurisdictional ratepayers are paying for costs that should be allocated 100% to FERC jurisdictional ratepayers.[802]

Since the Commission cannot know at this time how much SCE has and will over-collect, DRA recommends that the Commission not approve any of SCE's requested 2012 rate increase until a thorough audit of SCE's books has been completed. In the alternative, the Commission could open an Order Instituting Investigation (OII) to look into this issue and not set rates until the OII has been completed. Or, if the Commission decides to authorize a rate increase, it could set the rates subject to refund depending on the outcome of audit/OII.

SCE's forecast for Account 566.280, the account in which SCE records NERC CIP compliance costs, is $11,626 million; $5,744 million greater than what SCE recorded in 2009. Of the $5,744 million requested increase, SCE is seeking $2,552 million ($912,000 for labor, $1,640 million for non-labor) for NERC CIP compliance costs.

In its Direct testimony, SCE states that it needs six additional employees to comply with NERC reliability standards. SCE says these additional employees are necessary to, among other things, "[d]evelop and implement new cyber security controls."[803] In addition, SCE is seeking

---

[801] To be absolutely clear, DRA is not suggesting that SCE does not have to comply with NERC CIP requirements. The issue DRA raises is whether or not SCE has properly recorded the costs associated with compliance. DRA believes that SCE has not. SCE's showing in this matter is inconsistent and vague making it **impossible** to determine that SCE has not been double-collecting NERC CIP costs from both CPUC jurisdictional ratepayers and FERC jurisdicitonal ratepayers. SCE's references to its R/O model do bear out SCE's explanation because the R/O model does not provide great enough granularity for the Commission to determine that NERC CIP compliance costs have been recorded properly.

[802] The R/O model allocates costs to CPUC jurisdictional and FERC jurisdictional ratepayers based on a percentage that is determined outside the model. The percentage is derived by adding up all the CPUC recorded expenses (in a FERC account) and dividing by the total expenses. If costs are improperly recorded, this will result in the wrong percentage being applied by the R/O model to CPUC jurisdictional ratepayers. SCE confirmed this during cross-examination (see, 22 RT 3684:3-13, Varvis/SCE.

[803] See, Ex. SCE-03, Vol. 5, Part 3, pp. 9. Note, the funding for the 6 employees requested in this case is in addition to the 2 SCE employees currently working to maintain compliance with existing NERC reliability standards. (See, *Id* at 10:2-4).

$1,640 million in non-labor expenses "primarily for NERC [CIP] reliability standards."[804] SCE goes on to say that the areas in which it will incur expenses: $800,000 "for an ongoing cyber-vulnerability assessment"[805] and $1,053 million to "identify assets subject to the reliability standards, develop and implement organizational and technical controls, and enforce compliance and controls."[806] SCE then spends seven pages in Appendix B to SCE-03, Vol. 5, Part 3, to try to justify its request in this case.

SCE goes even further in its Rebuttal testimony in trying to bolster support for its request. In response to DRA's recommendation that the Commission reject SCE's request because SCE has embedded costs in its historical expenses, SCE states that DRA ignores all of SCE's testimony and associated workpapers and that:

> [w]hile historical expenses reflect some costs associated with NERC Reliability Standards, the requirements of those standards have been increasing … [and] DRA's claim that SCE already has sufficient funding to handle compliance with those standards ignores these growing demands.[807]

During cross-examination, not only does SCE again admit that NERC CIP compliance costs are embedded in rates,[808] SCE clearly states that it considers it appropriate to seek these costs in this GRC[809] and that SCE did seek them in prior GRCs.[810] In fact, SCE not only sought recovery of these expenses in its TY 2009 case, SCE got the Commission to grant its request.[811]

However, when presented with clear and convincing evidence that it is improper to collect NERC CIP compliance costs from CPUC jurisdictional ratepayers, SCE all of a sudden

---

[804] *Id* at 10.

[805] *Id*. Note: the fact that these are "ongoing" expenses is further evidence that SCE has improperly embedded NERC CIP compliance costs in existing rates.

[806] *Id*. (The remainder of $265,000 is for travel and employee expenses for the incremental staff and contractors).

[807] See, Ex. SCE-18, Vol. 5, Part 3&4, pp. 4:22-25 and p. 5:1 and 19-20, emphasis added.

[808] See 10 RT 1137:22-25, Reeves/SCE.

[809] *Id* at1136:19-22.

[810] *Id* at 1136: 23-25.

[811] Further proof that SCE has embedded NERC CIP compliance costs in prior and current rates, the Commission, in D.09-03-025, stated that SCE "did not spend its entire 2007 forecast amount in 2007 because FERC took more time than SCE expected to approve the Critical Infrastructure Project Reliability Standards. FERC merely postponed implementation to 2008. SCE must now satisfy two FERC milestone dates, June 2009 and June 2010. SCE's 2007 IT Critical Infrastructure Project capital expenditures of $3.123 million are reasonable and are adopted." D.09-03-025, p. 234.

changed its tune. During cross-examination, SCE's subject matter expert was asked whether SCE was seeking to recover NERC CIP costs at FERC. SCE's witness did not know.812

DRA then presented SCE with two exhibits, both excerpts from SCE's Transmission Owner rate case filed at FERC in June 2011. These exhibits unequivocally show that 100% of NERC CIP compliance costs are recoverable through FERC jurisdictional rates and not CPUC jurisdictional rates.[813] When asked, after reviewing portions of SCE's FERC filing, whether the SCE witness still believed it proper to collect NERC CIP compliance costs in its 2012 GRC, SCE stated that these expenses should not be recovered in this rate case.

> Q Is it still your contention that for NERC compliance, Edison should be recovering funds in this GRC?
>
> A I'm – it says a hundred percent FERC here, so yes. So it should not be recovered in this GRC.[814]

DRA then asked the witness whether, based on the proof that it is improper to collect NERC CIP compliance costs from CPUC jurisdictional ratepayers, SCE would agree to submit errata removing all CIP compliance costs from this rate case,[815] SCE's witness not only stated that SCE would do no such thing, SCE came up with a brand new rationale as to why CPUC ratepayers are not and would not be subject to these requested NERC CIP compliance costs.[816] According to SCE, the R/O model will apply the appropriate costs to CPUC jurisdictional ratepayers: "It's not a matter of errata. It's a matter of what percentage gets applied to the costs. In this case, the jurisdictional calculation takes care of that."[817] SCE's showing in this case does not support that conclusion.

SCE's pronouncements to the contrary are belied by two facts: (1) unequivocal statements made by SCE in testimony that CPUC ratepayers should pay for these requested expenses and (2) the way in which SCE deals with FERC jurisdictional expenses in this rate case.

---

[812] See, 10 RT 1138:2-4, Reeves/SCE.

[813] See, DRA Exhibit 37 and 38.

[814] See, 10 RT 1141:23-28, Reeves/SCE.

[815] *Id* at 1142:8-13.

[816] *Id* at 1142:5-7 and 1142:14-21.

[817] *Id* at 1143:11-15.

SCE could not have more clearly stated that it is seeking funding in **this** rate case for NERC CIP compliance costs. In addition to the quoted portions above, SCE's Vice President of the Regulatory Operations Division in the Regulatory Policy and Affairs (RP&A) Department, whose responsibilities include directing activities of the FERC Rates and Regulation Section of the RP&A Department, clearly and unequivocally states in response to DRA's recommendation to reject SCE's request for NERC CIP compliance costs:

> SCE strongly urges the Commission to reject DRA's proposed disallowances of ratepayer funding for SCE's NERC CIP-related compliance efforts and adopt SCE's forecast of 2012 Test Year NERC CIP O&M and capital-related expenditures as reflected in Table I-1.[818]

It should be of no surprise to the Commission that Table I-1, referenced in the quote above, includes the total amount requested by SCE for NERC Compliance costs (all $2.552 million of them). It is imperative to note that, at **no** point in its testimony, whether Direct or Rebuttal, did SCE state or even try to make clear to the Commission that SCE was not seeking these NERC CIP compliance costs to be borne by CPUC jurisdictional ratepayers. Everything other than statements made when presented with the irrefutable evidence of SCE's own FERC filing demonstrates that SCE is seeking funding in this rate case for NERC CIP compliance costs.

Moreover, if the above is not clear and convincing evidence that SCE is seeking to improperly double collect funding for NERC CIP compliance costs from both its FERC jurisdictional and CPUC jurisdictional ratepayers, the Commission should contrast SCE's showing and request for these CIP compliance costs with how SCE dealt with funding for AA-Bank replacement transformers.

In trying to justify inclusion of NERC CIP costs in CPUC jurisdictional rates, SCE uses over 20 pages (400 lines) of testimony, by at least two witnesses, at least 4 pages of workpapers and information provided in a number data request responses.[819] In contrast, when discussing AA-Bank replacement transformers, SCE uses a total of 8 lines.[820] Presumably, the reason SCE spends so little time and effort discussing its request for funding the replacement of these

---

[818] See, SCE-22, Vol. 03, Part 1, p. 19.

[819] See, Ex. DRA-5, p. 168-171; and Ex. SCE-18, Vol. 5, Part 3&4, Attachment 3, SCE data responses to TURN.

[820] Ex. SCE-3, Vol. 3, Part 3, Ch. I-II.

transformers is because the funding associated with these transformers is completely, 100% FERC jurisdictional: "[t]he replacement of AA-Bank transformers is completely under FERC jurisdiction and is, therefore, not discussed further in this testimony."[821]

Based on this and the pages of testimony and argument spent by SCE in support of its funding request, one is left with only one conclusion, SCE is affirmatively seeking to over-collect from its ratepayers. In these extremely tough economic times, SCE's callous disregard for its ratepayers is despicable. This Commission must not grant to SCE the authority to increase rates until the Commission directs an independent auditor to audit SCE's books. and determine how SCE has recorded NERC CIP compliance costs. An important reason for requiring an audit of SCE's books is that SCE's R/O model cannot provide a great level of granularity than the $11,626 million recorded to account 566.280. It impossible to currently determine if the R/O's jurisdictional allocation properly accounts for NERC CIP compliance costs. That is, no one at this point, with the evidence on record, can determine if NERC CIP compliance costs have been properly recorded; and SCE admits this.[822]

DRA notes that SCE has admitted that, if costs were improperly recorded, the CPUC percentage split would be incorrect and would result in an over collection of rates:

> Q. And it's true that … if any NERC/CIP dollars were left in the CPUC side of the ledger, the percentages shown for the split between CPUC and FERC would be different; is that correct?
>
> A. That's right.
>
> Q. And if dollars were left in on the CPUC side of the ledger, the CPUC share percentage wise would increase by some number; is that correct?
>
> A. Correct.[823]

When asked whether or not, SCE now agreed with DRA's concern[824] that SCE was double collecting, SCE responded no.[825] SCE may not share DRA's concern, but the

---

[821] See, Ex. SCE-3, Vol. 3, Part 3, Ch. I-II, p. 68.

[822] See, 22 RT 3683:6-14 that, subject to check, the R/O model cannot delve deeper into SCE's requested $11,626 million. SCE has not corrected this response.

[823] See, 22 RT 3684:3-13, Varvis/SCE.

[824] See, Ex. SCE-18, Vol. 5, Part 3&4, pp. 6:15 and fn 13, quoting from a DRA data request response to SCE (SCE-DRA_TLG-012, Question 77, included as attachment 5 to Ex. SCE-18, Vol. 5, Part 3&4).

[825] See, 10 RT 1170:2-6, 1170:24-28, and 1171:1-3, Reeves/SCE.

Commission should. SCE has not only failed to meet its burden of proof justifying NERC CIP compliance costs as appropriately borne by its ratepayers, but is seeking to over collect funds from its ratepayers. This Commission should not only require SCE to disgorge improperly obtained funds, it should also determine appropriate sanctions for SCE's for its actions.

6. Customer Service

SCE's Customer Service Business Unit (CSBU) has the Customer Service Operations Division (CSOD), which delivers customer services to all SCE customers, and the Customer Service and Information Delivery (CS&ID) functions, which addresses the customer service needs of SCE's nonresidential customers such as government, commercial, industrial, and agricultural customers.[826] The Operation and Maintenance (O&M) expenses for the Customer Service Operations activities are recorded in Federal Energy Regulatory Commission (FERC) Accounts 901 through 905, which are designated as "Customer Accounts" and certain portions of FERC Accounts 580, 586, 587, and 597, which are designated as "Distribution Accounts."[827] CS&ID records expenses in FERC Accounts 907, 908, 916 (CS&ID Accounts), 920, 927 (A&G Accounts), and 408 (Tax Expense Accounts).[828]

6.1. Customer Service Expenses – Integration of Edison SmartConnect Costs and Benefits

In the Edison SmartConnect deployment decision (D.08-09-039), the Commission approved a Settlement Agreement between SCE and DRA that established the Edison SmartConnect Balancing Account (ESCBA) for operation through the end of 2012. According to SCE, because the ESCBA will operate during 2012, the TY 2012 forecast for CSBU operations needs to be developed on a business as usual basis without Edison SmartConnect costs or benefits, whereby in 2012, all Edison SmartConnect incremental costs and benefits will continue to flow through the ESCBA. SCE's TY 2012 forecast for CSBU operations will include normal ratemaking treatment of all non-Edison SmartConnect related costs and benefits and include FERC Account-by-FERC Account adjustments for customer growth, productivity

[826] Ex. SCE-4, Vol. 3, p. 1.

[827] Ex. SCE-4, Vol. 2, pp. 1 and 115.

[828] Ex. DRA-10, p. 1.

and non-Edison SmartConnect-related program changes forecasted between the recorded 2009 base year and the TY 2012.[829]

DRA forecasts TY 2012 expenses for CSBU operations on a business as usual basis without Edison SmartConnect costs or benefits.

SCE anticipates that SmartConnect deployment will be fully implemented by the end of 2012. SCE developed a forecast to reflect the expected CSBU operations in 2013 based on the assumption that Edison SmartConnect will be fully deployed throughout CSBU. SCE developed the 2013 forecast by using 2009 recorded costs as the starting point and included all forecasted Edison SmartConnect incremental costs and benefits. The separate 2013 forecast for CSBU operations will be reflected in SCE's 2013 attrition mechanism as a specific adjustment.[830] SCE states that this method provides avoidance of double recovery and increased transparency of cost recovery.[831]

DRA also includes in its testimony forecasts for 2013 expenses assuming the Edison SmartConnect deployment is fully implemented. If the Commission does not adopt DRA's Post Test Year Ratemaking proposals,[832] DRA asks the Commission to adopt DRA's 2013 CSBU forecasts as set out in this section of the Brief.

6.2. Customer Service Expenses – Operations

6.2.1. FERC Account 901 – Business Unit Management and Support

SCE records costs incurred in the general management and support of Customer Service Operations, such as Finance and Administration, Business Planning, Regulatory and Tariff Program Support, Training, and Program Management Organization support of Customer Service in FERC Account 901.[833]

For its "business as usual scenario" for TY 2012, SCE is requesting $14.630 million or an increase of $2.568 million above 2009 recorded expenses of $12.062 million for FERC Account

[829] Ex. SCE-4, Vol.1, p.15.

[830] Ex. SCE-4, Vol.1, pp. 15 and 16.

[831] Ex. SCE-4, Vol.1, p. 24.

[832] See Ex. DRA-21, and Section 16 of this Brief.

[833] Ex. SCE-4, Vol.1, p. 118.

901.[834] DRA recommends a TY 2012 forecast of $13.332 million, or an increase of $1.270 million above 2009 recorded expenses.[835]

SCE used 2009 recorded expenses of $12.062 million and made six test year adjustments, all of which are increases, to forecast TY 2012 expenses.

The first test year adjustment is a $221,000 increase to reflect a cumulative customer growth rate 1.83 % for 2009 to 2012.[836]

The second test year adjustment is a $1.139 million increase for the addition of five full time equivalent employees (FTEs) plus associated non-labor expenses to support CSBU's Major Technology initiatives in SCE's Program Management Organization.[837]

The third test year adjustment of a $56,000 increase is for the addition of one FTE plus associated non-labor expenses in the Payroll and Administrative Services departments.[838]

The fourth test year adjustment is a $773,000 increase for the addition of nine employees plus associated non-labor expenses for training for technology enhancements made to CSBU customer service and information systems. In addition, other non-labor expenses are added for consultants and training materials.[839]

The fifth test year adjustment is a $147,000 increase for the development and delivery of training modules of SCE's Plug-in Electric Vehicle (PEV) program.[840]

The sixth test year adjustment is a $232,000 increase for training and support of the Home Area Network (HAN) technologies for the Customer Communication Organization (CCO).[841]

DRA recommends using the five-year average of recorded labor and non-labor expenses to forecast the TY 2012 for FERC Account 901. During 2005 to 2009, the recorded expenses

---

[834] Ex.SCE-4, Vol. 2, p. 123.

[835] Ex. DRA-10, p. 10.

[836] Ex. SCE-4, Vol. 2, p. 122.

[837] Ex. SCE-4, Vol. 2, pp. 122 and 123.

[838] Ex. SCE-4, Vol. 2, p. 123.

[839] Ex. SCE-4, Vol. 2, p. 123.

[840] Ex. SCE-4, Vol. 2, p. 123.

[841] Ex.SCE-4, Vol. 2, p. 123.

generally declined with the exception of 2008 when recorded expenses increased to $14.096 million, but then dropped to the lowest recorded expense level of $12.062 million in 2009.

DRA also disagrees with SCE's TY 2012 adjustment of a $221,000 increase to reflect a cumulative customer growth of 1.83 % for 2009 through 2012. SCE has not demonstrated that the expenses in FERC Account 901 are directly proportionate to the customer growth rate. The recorded expenses for FERC Account 901 were at the highest level of $14.239 million in 2005 and declined to the lowest level of $12.062 million in 2009. Past recorded data shows that recorded expenses in FERC Account 901 have declined despite recorded annual customer growth during 2005 to 2009.[842]

In Rebuttal, SCE says it has "...demonstrated the direct relationship of its overall labor related costs to customer growth over the last four years."[843] According to SCE "... this relatively subtle relationship ... is obscured by other factors, including, for example variations in training requirements due to ERP, filling of vacancies, and changes in labor allocations."[844]

SCE's explanation for the undeniable decrease in expenses in 2009 is so subtle as to be downright oblique. Unsubstantiated allusions to labor allocations, productivity initiatives, and statistical theories[845] do not obscure the fact that SCE's own data contradicts the link SCE attempts to make between its customer growth and its recorded costs.

DRA's recommendation of $13.332 million will allow SCE to increase FTEs in the Business Unit Management and Support departments. SCE is requesting a 50% increase in the number of FTEs in its Program Management Organization (PMO) for a funding increase of $1.139 million. At the end of 2009, the number of FTEs in the PMO was 9.8.[846] SCE is requesting an additional five FTEs for 2012. DRA's recommendation for an increase of $1.270 million above 2009 recorded expenses will allow SCE to increase FTEs in the PMO, and add FTEs for Finance and Administrative activities and training for CSBU's Customer Service Systems. Moreover, SCE has historically administered training programs to its CSBU staff. For example, SCE explains that training expense related to new Customer Service systems is

---

[842] Ex. DRA-10, p. 11, Table10-6.

[843] Ex. SCE-19, p. 34.

[844] Id.

[845] Ex. SCE-19, pp. 26, 34.

[846] Ex. DRA-10, p. 11 citing SCE's response to DRA-SCE-032-SWC, Q/A 2.b.

expected to take place over a four-year period on a scope and scale similar to the ERP/SAP training program that took place in 2008.[847] Therefore, training expense for different training programs are already embedded in historical recorded costs.

Second, DRA recommends removing SCE's entire funding request increases for PEV for TY 2012 which are above 2009 recorded levels. SCE instituted a PEV Readiness Program and recorded $2.284 million for this program in 2009. Thus, SCE already has these embedded costs for PEV Readiness.

In its TY 2009 GRC, SCE was authorized $9.726 million for its Low Emission Vehicle (LEV) program and engineering advancement which includes a customer education and outreach information program. SCE recorded $11.197 million for the LEV program in 2009.[848] Some of SCE's past recorded costs for its LEV program can also be used for PEV costs. For example, SCE has an 800 number as part of it customer education and outreach component of SCE's existing Low Emission Vehicle program. Since 2005, SCE has received 954 calls at this number which provides recorded messaging on various electric vehicle topics. SCE does not track customer calls received through its general service 800 number regarding electric vehicle questions. In addition, SCE introduced a PEV microsite on its website to educate customers on the process of purchasing PEVs and to provide important electric service related information that customers who purchase a PEV may require for overall PEV readiness. The microsite also provides customers with the capability to inquire about PEVs via email. Since November 2009, SCE received 277 PEV related email inquiries.[849]

SCE forecasts that there will be 21,090 PEVs in its service area by the end of 2012.[850] As of February 2011, there were only approximately 100 PEVs in SCE's service area.[851] Based on the actual number of PEVs in SCE's service, SCE's forecast of 21,090 PEVs by the end of 2012 seems extremely unlikely. In any event, SCE customers who purchase PEV will receive information about charging the PEV from auto manufacturers and dealerships. Therefore, DRA

---

[847] Ex. DRA-10, p. 11, citing SCE's response to DRA-SCE-032-SWC, Q/A 4.b.

[848] Ex. DRA-10, p. 12, citing SCE Handout, "Plug-in Electric Vehicle Readiness," in meeting with DRA on February 22, 2011, pp. 2 and 3, and SCE's response to DRA-SCE-035-SWC, Q/A 5.e.

[849] Ex. DRA-10, p. 12, citing SCE's response to DRA-SCE-035-SWC, Q/A 5.e.

[850] Ex. DRA-10, p. 12 citing SCE's response to DRA-SCE-032-SWC, Q/A. 5.

[851] Ex. DRA-10, p. 12 citing DRA meeting with SCE on February 22, 2011 regarding PEV Readiness.

recommends no additional funding for SCE's PEV program above 2009 recorded levels, an adjustment of $147,000.

Third, DRA recommends removing HAN program costs for TY 2012. SCE forecasts that it will have 116,000 customers with HAN devices at year-end 2012.[852] However, availability of HAN product devices is dependent on the ratification of HAN standards, Smart Energy Profile (SEP) 2.0, by the National Institute of Standards and Technology (NIST) which has not yet happened. SCE states that the latest SEP 2.0 project schedule forecasts final ratification of the standard in June 2011 by the ZigBee Alliance, the industry consortium developing SEP 2.0, with NIST ratification thereafter. Thereafter, product development and testing of HAN devices will begin by manufacturers. SCE optimistically speculates that it is reasonable to assume SEP 2.0-based products to be commercially available in the fourth quarter of 2011 or first quarter 2012.[853]

At the time the evidentiary hearings were being held in August 2011, the HAN standards still had not been ratified. At this time, one can only speculate as to the number of SCE customers that will have HAN devices and to the extent of communication that SCE will have with its customers with HAN devices in 2012. As SCE said, in response to questions by the ALJ, for purposes of SCE's residential customers, the idea is that a customer has various devices inside the house that communicate to the meter so that customer can take advantage of different pricing.[854] SCE enumerates devices at the premises as "smart appliances," "an information display," and a "gateway device" that enables a customer to communicate on an I-phone or an I-Pad. While SCE's customers may want these features in the future, there is no evidence that they are clamoring for them now. There does not appear to be any basis in fact for SCE's assumption that, in the 2012 Test Year, SCE's customers, who live in some of the areas hardest hit by the recession are going to be out buying "smart appliances" so they can communicate with SCE about energy usage.

Moreover, SCE's SmartConnect proceeding has provided some funding for some HAN functionality such as SCE's Programmable Communicating Thermostat (PCT) program.[855] SCE has proposed to modify ESCBA so that the costs authorized in D. 08-09-039 for HAN

---

[852] Ex. DRA-10, p. 13, citing SCE's response to DRA-SCE-032-SWC, Question 6.

[853] Ex. DRA-10, p. 13, citing SCE's response to DRA-SCE-035-SWC, Question 6.d.

[854] 15 RT 2097-2098, Oliva/ SCE.

[855] Ex. SCE-4, Vol. 1, pp. 4 and 30.

functionalities related to the PCT program remain in operation for purposes of recording authorized costs through 2014 because these costs are expected to be incurred in 2013 and 2014. SCE states that the implementation of the PCT program has been postponed due to an unanticipated delay in the Advanced Load Control System (ALCS) technology, and the provisions of In-home Displays (IHDs), which have been postponed due to a delay in the adoption of the Smart Energy Profile 2.0 HAN national standard.[856]

For all these reasons, DRA recommends no additional funding for SCE's HAN programs for TY 2012, an adjustment of $232,000.

In its Rebuttal, SCE argues that DRA's proposals "impair" SCE's ability to achieve State and Commission energy policy goals,"[857] or are "inconsistent with National, State and Commission policy directives.[858] These generalizations are not supported by any evidence that the increases SCE seeks are actually necessary in TY 2012. Now is not the time to ask SCE's struggling ratepayers to pay for SCE to attempt to position itself as some sort of energy policy leader. DRA continues to recommend ratepayer funding in TY 2012 of no more than $13.332 million for FERC Account 901.

For 2013, if Smart Connect is fully deployed, SCE seeks $14.772 million, or an increase of $2.710 million above 2009 recorded expenses. DRA recommends a 2013 forecast of $13.332 million.[859]

SCE used 2009 recorded expenses of $12.062 million and made seven test year adjustments to forecast 2013 expenses.

The first 2013 adjustment reduces operating expenses by $210,000 due to the full deployment of Edison SmartConnect program as fewer training specialists will be needed to provide training to meter readers and Field Service Representatives.[860]

The second 2013 adjustment increases operating expenses by $323,000 to reflect a cumulative customer growth rate of 2.73 % for 2009 to 2013.[861]

---

[856] Ex. SCE-4, Vol. 1, p. 30.

[857] Ex. SCE-19, p. 4.

[858] Ex. SCE-19, p. 6.

[859] Ex. DRA-10, p. 14.

[860] Ex.SCE-4, Vol. 2, p. 124.

[861] Ex. SCE-4, Vol. 2, p. 124.

The third 2013 adjustment is an increase of $1.496 million for the addition of eight full time equivalent employees (FTEs) plus associated non-labor expenses to support CSBU's Major Technology initiatives in SCE's Program Management Organization.[862]

The fourth 2013 adjustment is a $56,000 increase for the addition of one FTE plus associated non-labor expenses in the Payroll and Administrative Services departments.[863]

The fifth 2013 adjustment is a $773,000 increase is for the addition of nine employees plus associated non-labor expenses for training for technology enhancements made to CSBU customer service and information systems. In addition, other non-labor expenses will be needed for consultants and training materials.[864]

The sixth 2013 adjustment is a $40,000 increase for the development and delivery of training modules of SCE's Plug-in Electric Vehicle (PEV) program.[865]

The seventh 2013 adjustment is a $232,000 increase is for training and support of the Home Area Network (HAN) technologies for the Customer Communication Organization (CCO).[866]

DRA's 2013 forecast of $13.332 million is an increase of $1.270 million above 2009 recorded expenses. This will allow SCE to increase FTES in the Business Unit Management and Support departments.

DRA disagrees with SCE's second 2013 adjustment of a $323,000 increase to reflect a cumulative customer growth of 2.73 % for 2009 through 2013. SCE has not demonstrated that the expenses in FERC Account 901 are directly proportionate to the customer growth rate. The recorded expenses for FERC Account 901 were at the highest recorded expense level in 2005 and declined to the lowest recorded expense level in 2009 despite recorded annual customer growth during the 2005 to 2009 period.

DRA recommends no ratepayer funding for SCE's third through seventh 2013 forecast adjustments for the same reasons as discussed above in connection with DRA's recommendations for TY 2012..

---

[862] Ex.SCE-4, Vol. 2, pp.124 and 125

[863] Ex. SCE-4, Vol.2, p. 125.

[864] Ex. SCE-4, Vol. 2, p. 125.

[865] Ex. SCE-4, Vol. 2, p. 125.

[866] Ex. SCE-4, Vol. 2, p. 125.

6.2.2. FERC Account 902 – Meter Reading Expenses

FERC Account 902 captures all expenses related to the reading of customer meters.[867] FERC Account 902.300 is a new sub-account to record activities associated with the SmartConnect Operations Center.[868]

For SCE's TY 2012 "business as usual" scenario, SCE is requesting $45.113 million or an increase of $812,000 above 2009 recorded expenses of $44.301 million for FERC Account 902.[869] DRA recommends a TY 2012 forecast of $44.301 million.

SCE used 2009 recorded expenses of $44.301 million and made an adjustment of an $812,000 increase for the cumulative customer growth of 1.83 % from 2009 to 2012 to forecast 2012 expenses.[870]

DRA recommends using the 2009 recorded expenses of $44.301 million to forecast 2012 expenses. DRA disputes SCE's proposal of an $812,000 increase because SCE has not demonstrated that the expenses in FERC Account 902 are directly proportionate to the customer growth rate. The recorded expenses for FERC Account 902 were at the highest level of $46.928 million in 2008 and declined to the lowest level of $44.301 million in 2009. Past recorded data shows that recorded expenses in FERC Account 902 have declined from 2008 to 2009 despite the recorded annual customer growth during this period.

For 2013, SCE is requesting $12.340 million or a decrease of $31.961 million below 2009 recorded expenses for FERC Account 902.[871] DRA is recommending $12.012 million.

SCE used 2009 recorded expenses of $44.301 million and made two test year adjustments to forecast 2013 expenses. The first 2013 adjustment is a $32.289 million reduction due to the full deployment of Edison SmartConnect and the elimination of approximately 720 FTEs in the Meter Services Organization and associated non-labor costs. The second 2013 forecast adjustment is a $328,000 increase for the cumulative customer growth of 2.73 % from 2009 to 2013.[872]

---

[867] Ex. SCE-4, Vol. 2, p. 125.

[868] Ex. SCE-4, Vol. 2, p. 133.

[869] Ex. SCE-4, Vol. 2, p. 129.

[870] Ex.SCE-4, Vol. 2, p. 129.

[871] Ex. SCE-4, Vol., p. 130.

[872] Ex. SCE-4, Vol.2, p. 130.

DRA recommends using the 2009 recorded expenses of $44.301 million as the base to forecast 2013 expenses. DRA does not dispute the $32.289 million reduction due to the full deployment of Edison SmartConnect and the elimination of approximately 720 FTEs in the Meter Services Organization and associated non-labor costs. However, DRA does dispute SCE's 2013 forecast increase of $323,000 for cumulative customer growth of 2.73% from 2009 through 2013 for the same reasons discussed above. DRA recommends that $323,000 increase be removed.

Given the substantial ratepayer funding SCE has received for the new SmartConnect meters, SCE should have the motivation to significantly minimize and ultimately eliminate these costs. DRA's forecast is reasonable in light of the full deployment of SmartConnect meters.

6.2.2.1. FERC Sub-Account 902.300 – Operations Center

SCE says that, with the completion of Edison SmartConnect deployment in 2012, the SmartConnect Operations Center (SOC) will be a part of MSO operations. The SOC will plan, monitor, operate and maintain the Edison SmartConnect meter and communication system. The functions of the SOC will be funded through the Edison SmartConnect balancing account (ESCBA) consistent with Decision (D.) 08-09-039 until the end of 2012. SCE says that FERC Account 902.300 is for a new activity so no historical expense data exists.[873]

For its TY 2012 "business as usual" scenario, SCE is requesting $1.089 million for FERC Account 902.300.[874] DRA recommends $0.

SCE's TY 2012 forecast includes a $760,000 increase to support the PEV program in which the MSO will incur non-labor implementation and maintenance costs for Information Technology applications and communication systems related to the PEV program.[875] SCE's TY 2012 forecast also includes a $329,000 increase to support the HAN program that SCE says was not included in SCE's SmartConnect deployment costs in which the MSO anticipates incremental costs for detailed troubleshooting and diagnostics related to the HAN-enabled customer devices.[876]

---

[873] Ex. SCE-4, Vol. 2, p. 131.

[874] Ex. SCE-4, Vol. 2, p. 132.

[875] Ex. SCE-4, Vol. 2, p. 132.

[876] Ex. SCE-4, Vol. 2, p. 132.

DRA is recommending $0 for TY 2012 for FERC Account 902.300. This activity is, or should be, funded through the Edison SmartConnect balancing account to be consistent with Decision (D.) 08-09-039 until the end of 2012. Second, DRA disputes SCE's request for additional funding for its PEV and HAN programs as discussed above in FERC Account 901.

For 2013, SCE is requesting $13.115 million for the 2013 Forecast for FERC Account 902.300. DRA recommends a 2013 forecast of $4.098 million.

First, SCE's forecast includes an increase of $770,000 to support the PEV program. Second, SCE is requesting an increase of $422,000 to support the HAN program.[877] Third, SCE forecasts an increase of $11.923 million to support the installation and ongoing maintenance of the telecommunication data management system at the SmartConnect Operations Center. SCE's forecast of $11.923 million is comprised of $3.304 million in labor for 29 employees to provide on-going oversight and maintenance support associated with the operation of the SmartConnect meter and communication system and $8.620 million for telecommunication costs associated with the SOC.[878] The 2009 to 2012 costs to operate SOC will be recovered through the ESCBA over the SmartConnect deployment period and is not included in the 2012 forecast.[879]

DRA is recommending a 2013 forecast of $4.098 million. DRA's forecast to operate the SOC for 2013 is comprised of $1.556 million for labor expense, and $2.541 million for non-labor expense.

SCE claims that FERC Account 902.300 is a new activity and no historical data exists. However, historical cost data does exist as the functions of the SOC began operating in 2010. The SOC has been funded through the Edison SmartConnect balancing account. DRA reviewed the recorded costs to operate the SOC for 2010 and year-to-date February 2011.

To forecast the labor expense, DRA recommends taking the year-to-date February 2011 recorded labor cost of $259,325 and annualizing the two months of recorded costs to $1.556 million to forecast 2013 labor expenses. The 2010 recorded number of FTEs working in the SOC was 13.1. SCE states that the number of FTEs working in the SOC in 2011 will be 17 based on the annualized recorded hours year-to-date through February 2011.[880] SCE forecasts

---

[877] Ex. SCE-4, Vol. 2, pp. 133 and 134.

[878] Ex, DRA-10, p. 21, citing SCE Workpapers to Exhibit SCE-4, Volume 2, Chapter IV, p. 93.

[879] Ex. DRA-10, p. 21 citing SCE's response to DRA-SCE-208-SWC, Q/A 1.a.

[880] Ex. DRA-10, p. 22 citing SCE's response to DRA-SCE-208-SWC, Q/A 1.a.

a staff of 29 FTEs in 2013 to operate the SOC. As SCE states, the number of FTEs working in the SOC in 2011 will be 17 based on the annualized recorded hours year-to-date through February 2011. To forecast the non-labor expenses, DRA recommends taking the year-to-date February 2011 recorded non-labor cost of $259,325 and annualizing these two months of recorded costs to $2.541 million to forecast 2013 non-labor expenses. DRA's recommendation is reasonable given that the monthly 2010 and the monthly year-to-date February 2011 non-labor expenses and telecommunications expenses show a decrease from 2010 to 2011.

Finally, DRA disputes SCE's inclusion of PEV and HAN related expenses for the reasons explained in the discussion for FERC Account 901. DRA recommends a $1.192 million adjustment for these.

6.2.3. FERC Account 903 – Customer Records and Collections

FERC Account 903 includes all labor and non-labor expenses activities involved with processing customer applications for service, receiving payments, conducting customer credit activities, producing and delivering bills, and receiving and resolving customer inquires. The discussion that follows focuses on the accounts where DRA disagrees with SCE's TY 2012 forecast and 2013 forecast.

6.2.3.1. FERC Sub-Account 903.200 – Credit

The Credit Services function captures all costs associated with providing credit and collection services to SCE's customers for both active and closed accounts. Credit Administration and Field Services are the primary organizations recording expenses to FERC Subaccount 903.200.[881]

For its TY 2012 "business as usual" scenario, SCE is requesting $17.815 million, an increase of $820,000 above 2009 recorded expenses. DRA recommends a TY 2012 forecast of $16.995 million.

SCE used 2009 recorded expenses of $12.062 million and made five test year adjustments to forecast TY 2012 expenses.[882]

The first TY 2012 adjustment is an increase of $311,000 for the customer growth forecast of 1.83 % from 2009 to 2012.[883]

---

[881] Ex. SCE- 4, Vol. 2, p. 145.

[882] Id. at p. 149.

The second TY 2012 adjustment is an increase of $321,000 to support Field Service Representative (FSR) after hour service reconnections.[884]

The third TY 2012 adjustment is an increase of $74,000 for Field Services personnel to deliver final call notices in person to special needs customers.[885]

The fourth TY 2012 adjustment is an increase of $57,000 for one additional employee to support the mandated Red Flag alerts for customer verification and fraud prevention activities, given the expected 25 % increase in credit alerts activities due to the economic environment.[886]

The fifth TY 2012 adjustment is for an increase of $57,000 for one additional employee to support the monitoring and reviewing of deposit guarantors to support expected increased volumes.

DRA is recommending the use of the 2009 recorded expenses as the base to forecast TY 2012. First, DRA disputes SCE's TY 2012 adjustment of a $311,000 increase to reflect a cumulative customer growth of 1.83% for 2009 through 2012. SCE has not demonstrated that the expenses in FERC Subaccount 903.200 are directly proportionate to the customer growth rate. The recorded expenses for FERC Subaccount 903.200 were at the highest level of $18.499 million in 2005, and declined to the lowest level of $16.995 million in 2009. Past recorded data shows that recorded expenses in FERC Subaccount 903.200 have declined despite recorded annual customer growth during 2005 to 2009.

Second, DRA disputes SCE's TY 2012 adjustment of a $321,000 increase to support FSR after hour service reconnections. The number of field service credit disconnects and credit reconnects has declined from a high of 928,729 in 2008 to a low of 753,904 in 2010 which is the lowest number of credit disconnects and credit reconnects in six years. As the numbers of field service credit disconnects and credit reconnects decline, the number of potential FSR after hour service reconnections will decrease. Also, SCE will have the ability to remotely reconnect service for over 93 % of SCE's customers.[887]

---

[883] Id. at p. 148.

[884] Id. at p. 149.

[885] Id.

[886] Id.

[887] Ex. SCE-4, Vol. 2, p. 129.

SCE implemented customer service disconnection protections during 2010 and 2011 as ordered by the Commission in Rulemaking 10-02-005. These customer service disconnection protections will expire upon the effective date of the 2012 GRC.[888] Prior to the imposition of moratoriums on disconnects, SCE consistently had the highest disconnection levels of any of the investor owned utilities. Rather than allow SCE to return to this harsh and unreasonable practice, DRA recommends the Commission order SCE to continue to offer disconnection protections.

Third, DRA disputes SCE's TY 2012 adjustment of a $74,000 increase for Field Services personnel to deliver final call notices in person to special needs customers. SCE is already performing this function and the numbers of credit disconnects and credit reconnects have declined from 2008 to 2010.

Fourth, DRA disputes SCE's TY 2012 adjustment of a $57,000 increase to reflect its stated need for one additional employee to support the mandated Red Flag alerts for customer verification and fraud prevention activities. SCE has a program in place that provides SCE's telephone representatives the capability to run a "soft" credit inquiry and identification check while taking a turn-on request from new residential customers applying for service. In 2008, SCE developed a program that identifies and detects relevant warning signs for potential identity theft. SCE saw a 25 % increase in 2009 above the alerts received in 2008.[889] In 2009, SCE received over 36,000 alerts. However, the number of alerts received in 2010 decreased to 31,037.[890] The embedded recorded cost in 2008 and 2009 should be sufficient to cover this activity and DRA, therefore, recommends a $57,000 adjustment.

Fifth, DRA disputes SCE's adjustment of a $57,000 increase to support the monitoring and reviewing of deposit guarantors. SCE anticipates that 26% of the customers who require reconnection will take advantage of the option for a qualified guarantor to secure payment in the event of default in lieu of paying a cash deposit based on the number of residential reconnects by 2012.[891] SCE has used the deposit guarantor program primarily for customers establishing credit. SCE had 734 customers in 2008, 495 customers in 2009, and 455 customers in 2010 who

---

[888] Decision Implementing Methods to Decrease the Number of Gas and Electric Utility Service Disconnections (2010) D.10-07-048, Ordering Paragraph 15.

[889] Ex SCE-4, Vol. 2, p. 66.

[890] Ex. DRA-10, p. 27, citing SCE's response to DRA-SCE-220-SWC, Q/A 3.a.

[891] Ex. SCE-4, Vol. 2, p. 149 and Ex. DRA-10, p. 28, citing SCE Workpapers to Exhibit SCE-4, Volume 2, Chapter IV, p. 168.

used deposit guarantors to establish credit.[892] The number of SCE's customers who have used deposit guarantors to establish credit has decreased since 2008. SCE has embedded expenses to perform this function and SCE's ratepayers should not be required to fund an additional employee to support the monitoring and reviewing of deposit guarantors.

For 2013, SCE is requesting $11.662 million, a decrease of $5.333 million from 2009 recorded expenses for FERC Account 903.200.[893] DRA is recommending a 2013 forecast of $10.292 million.[894]

SCE used the 2009 recorded expenses and made the following adjustments.

The first 2013 forecast adjustment is a $6.703 million decrease to reflect a productivity savings from the Edison SmartConnect remote service switch (RSS).[895]

The second 2013 forecast adjustment is an increase of $281,000 for customer growth of 2.73 % from 2009 to 2013.[896]

The third adjustment is an increase of $321,000 to support FSR after hour service reconnections.[897]

The fourth adjustment is an increase of $74,000 for Field Service personnel to deliver final call notices in person to special needs customers.[898]

The fifth adjustment is an increase of $57,000 to reflect SCE's stated need for one additional employee to support the mandated Red Flag alerts given the expected 25% increase in credit alerts activities due to the economic environment.[899]

The sixth adjustment is for an increase of $57,000 for one additional employee to support the monitoring and reviewing of deposit guarantors to support expected increased volumes.[900]

---

[892] Ex. DRA-10, p. 28, citing SCE's response to DRA-SCE-220-SWC, Q/A 4.b.

[893] Ex. SCE-4, Vol. 2, p. 151.

[894] Ex. DRA-10, p. 30.

[895] Ex. SCE-4, Vol. 2, p. 150.

[896] Ex. SCE-4, Vol. 2, p. 150.

[897] Ex. SCE-4, Vol. 2, p. 150.

[898] Ex. SCE-4, Vol. 2, p. 151.

[899] Ex. SCE-4, Vol. 2, p. 151.

[900] Ex. SCE-4, Vol. 2, p. 151.

[900] Id.

The seventh adjustment is an increase of $580,000 to reflect increased alerts and notifications to customers as SCE says it expects that 25 % of customers currently receiving credit, billing and payment notices today will take advantage of this new electronic alerts offering.[901]

DRA recommends the Commission use the 2009 recorded expenses as the forecast for 2013 expenses.

First, DRA accepts SCE's first 2013 adjustment of a $6.703 million decrease to reflect savings from Edison SmartConnect RSS.

Second, DRA disputes SCE's proposed increase of $281,000 for customer growth of 2.73% from 2009 to 2013 for the same reasons as stated above for TY 2012.

Third, DRA disputes SCE's proposed increase of $321,000 to support FSR after hour service reconnections for the same reasons as stated above for TY 2012.

Fourth, DRA disputes SCE's proposed increase of $74,000 for Field Service personnel to deliver final call notices in person to special needs customers for the same reasons as stated above for TY 2012.

Fifth, DRA disputes SCE's proposed increase of $57,000 to reflect the need for one additional employee to support the mandated Red Flag alerts given the expected 25 % increase in credit alert activities due to the economic environment for the same reasons as stated above for TY 2012.

Sixth, DRA disputes SCE's proposed increase of $57,000 for one additional employee to support the monitoring and reviewing of deposit guarantors to support expected increased volumes for the reasons stated above for TY 2012.

Seventh, DRA disputes SCE's proposed increase of $580,000 to reflect increased alerts and notifications to customers. SCE is speculating that 25 % of its customers who currently receive credit, billing and payment notices today will take advantage of new electronic alerts offerings such as SMS text, email, and voice messaging. In any event, SCE currently has systems with the ability to send electronic alerts and notifications so costs should be embedded in recorded expenses.

---

[901] Id.

6.2.3.2. FERC Sub-Account 903.500 – Billing

For its 2012 "business as usual" scenario for the Billing group, SCE is requesting $17.902 million, an increase of $732,000 above 2009 recorded expenses. DRA recommends $17.170 million for 2012.

SCE used 2009 recorded expenses of $17.170 million and made three test year adjustments to forecast TY 2012 expenses.[902]

The first TY 2012 adjustment is an increase of $314,000 for customer growth of 1.83 % from 2009 to 2012.[903]

The second adjustment is an increase of $365,000 to reflect additional non-labor expenses in support of an enlarged bill format and a Braille billing option. SCE says it expects to support 1,000 customers for enlarged format and 1,000 customers for the Braille bill.[904]

The third adjustment is a $53,000 increase for one additional employee to support ongoing rate analysis and billing inquiries due to the introduction of PEV's in SCE's service territory.[905]

For its 2012 forecast, DRA recommends using the 2009 recorded expenses to forecast TY 2012.

As to SCE's proposed adjustments, DRA disputes the first TY 2012 adjustment of $314,000 that SCE says is to reflect a cumulative customer growth of 1.83 % for 2009 through 2012. SCE has not demonstrated that the expenses in FERC Account 903.500 are directly proportionate to the customer growth rate. The recorded expenses for FERC Account 903.500 were at the highest level, $19.156 million, in 2006 but declined to the lowest level, $17.170 million, in 2009. Past recorded data shows that recorded expenses in FERC Account 903.500 have declined despite recorded annual customer growth during 2006 to 2009. SCE also states that the Billing group is directly impacted by customer growth as more bills will be generated to new customers, creating additional routine operational work in billing process oversight, exception and manual processing.[906] However, the recorded number of billing

---

[902] Ex. SCE-4, Vol. 2, p. 160.

[903] Id.

[904] Id.

[905] Id.

[906] Ex.SCE-4, Vol. 2, p. 54.

exceptions shows that it does not necessarily correspond with the customer growth rate. For example, the total number of billing exceptions declined from a high of 2.305 million in 2007 to a low of 1.913 million in 2009 despite the growth in customers.[907]

DRA disputes SCE's second proposed increase of $365,000 which is supposed to reflect additional non-labor expenses in support of enlarged bill format and Braille billing option. SCE began offering customers the enlarged bill format in November 2008.[908] SCE did not offer the Braille billing option during 2005 to 2010.[909] DRA supports SCE's offering of the enlarged bill format and Braille billing option. However, SCE has not shown that additional funding will be needed in 2012 based on the recorded numbers of people receiving the enlarged bill format since SCE began offering this billing option in 2008. The number of customers receiving enlarged bill format was six in 2008, 76 in 2009, and 146 in 2010. SCE states that the costs for the enlarged bill format are not recorded or tracked separately from other billing functions. Currently, the print bill is manually enlarged on a color copy machine and then mailed to the customer. SCE calculates that the annual expense for providing customers with the enlarged bill format was $50 in 2008, $3,750 in 2009, and $7,200 in 2010.[910]

SCE says it expects that, in 2012, 1,000 customers will request the enlarged bill format and 1,000 customers will request the Braille bill. The enlarged bill format forecast is based on the Customer Service System's profile count of 1,002 customers who indicated that they have a sight impairment condition as of December 2010. SCE expects that, as outreach and communication efforts are increased to make customers aware of the enlarged bill format, more customers will request the large font bill option.[911] SCE states that

> SCE's forecast of 1,000 customers requesting the Braille billing option is supported by information from the Braille Institute of America which estimates that 4.8 % of the U.S. population is considered blind and that only 10 % of those considered blind have the ability to read Braille. Applying these statistics to SCE's 4.9 million customers, the estimated number of SCE customers considered blind and able to read a Braille bill is approximately

[907] Ex. DRA-10, p. 33.

[908] Ex. DRA-10, p. 33 citing SCE's response to DRA-SCE-220-SWC, Q/A 1.a.

[909] Ex. DRA-10, p. 33.

[910] Ex. DRA-10, p. 34 citing SCE's response to DRA-SCE-220-SWC, Q/A. 1.e.

[911] Ex. DRA-10, p. 34.

> 23,500 customers (4.9 million x 4.8% x 10%). SCE then assumed that only 5 % of its estimated Braille readers would take advantage of Braille billing option resulting in a forecast of 1,000 customers (23,500 x 5%).[912]

SCE says that, based on the Customer Service System profile count, as of December 2010, only 1,002 customers indicated that they have a sight impairment condition which would seem to include customers with a sight impairment condition as well as customers who are blind. DRA concludes that there would be fewer than 1,000 customers who would request enlarged bill format and fewer than 1,000 customers who would request the Braille bill option. SCE has offered the enlarged bill format for over two years and 146 customers have requested the enlarged bill format. Therefore, SCE does not need additional funding for the enlarged bill format and Braille bill option in 2012.

DRA disputes SCE's third proposed increase of $53,000 for one additional employee to support ongoing rate analysis and billing inquires due to the introduction of PEVs. DRA's discussion of the reasons it disputes these expenses are discussed above in connection with FERC Account 901.

For its 2013 forecast, SCE is requesting $21.364 million, an increase of $4.194 million above 2009 recorded expenses, for FERC Account 903.500.[913] DRA is recommending a 2013 forecast of $15.668 million.

SCE used 2009 recorded expenses of $17.170 million and made three test year adjustments to forecast 2013 expenses.[914]

The first 2013 forecast adjustment is a decrease of $1.5 million to reflect productivity savings in Edison SmartConnect operations due to accurate billing data, accurate completion of on and off orders, and improved data validations.[915]

The second 2013 forecast adjustment is a $4.938 million increase for 77 additional employees to support new rates that will use interval metering data due to the implementation of Edison SmartConnect meters.[916]

---

[912] Id.

[913] Ex. SCE-4, Vol. 2, p. 162.

[914] Ex. SCE-4, Vol. 2, p. 160.

[915] Ex. SCE-4, Vol. 2, p. 161.

[916] Id.

The third 2013 forecast adjustment is a $428,000 increase for customer growth of 2.73 % from 2009 to 2013.[917]

The fourth 2013 forecast adjustment is an increase of $277,000 to reflect additional non-labor expenses in support of an enlarged bill format and a Braille billing option. SCE expects to support 1,000 customers for enlarged bill format and 1,000 customers for the Braille bill.[918]

The fifth 2013 forecast adjustment is a $53,000 increase for one additional employee to support ongoing rate analysis and billing inquiries due to the introduction of PEV's in SCE's service territory.[919]

DRA is recommending using the 2009 recorded expenses of $15.668 million as the 2013 forecast for FERC Sub-Account 903.500 expenses.[920]

First, DRA accepts SCE's 2013 forecast adjustment for a decrease of $1.502 million.

Second, DRA disputes SCE's adjustment for an increase of $4.938 million for additional 77 FTEs to support new rates that will use interval metering data due to the implementation of the SmartConnect meters. SCE states that the Meter Data Management System (MDMS) provides all of the validation, editing, and estimating necessary to support customer usage calculations necessary to generate an accurate bill. SCE claims to expect billing usage analysis to increase in complexity as a result of advanced tariffs and programs that use interval usage data available with SmartConnect meters.[921] SCE planned, developed, and implemented the MDMS to meet SCE's specifications and requirements. The MDMS is an automated system that should generate accurate bills without much manual interference. DRA objects to SCE's request for 77 additional FTEs to support the MDMS and recommends an adjustment of $4.938 million.

Third, DRA disputes SCE's proposed increase of $428,000 for customer growth of 2.73% from 2009 to 2013 for the same reasons as discussed above for TY 2012.

Fourth, DRA disputes SCE's proposed increase of $277,000 to reflect additional non-labor expenses in support of enlarged bill format and Braille billing option for the same reasons as discussed above for TY 2012.

---

[917] Ex. SCE-4, Vol. 2, p. 162.

[918] Id.

[919] Id.

[920] Ex. DRA-10, p. 36.

[921] Ex. SCE-4, Vol. 2, p. 48.

Fifth, DRA disputes SCE's proposed increase of $53,000 for one additional employee to support ongoing rate analysis and billing inquiries due to the introduction of PEV's in SCE's service territory for the same reasons as discussed above for TY 2012.

6.2.3.3. FERC Sub-Account 903.800 – Customer Communication Organization

FERC Sub-Account 903.800 records the operating costs of the Customer Communication Organization (CCO) within SCE's Customer Service Operations, as well as the support-related costs of several other organizations such as Corporate Communications, Information Technology, and Operations Support.[922]

For its TY 2012 "business as usual" forecast, SCE is requesting $47.020 million, an increase of $7.535 million above 2009 recorded expenses, for FERC Sub-Account 903.800.[923] DRA recommends a TY 2012 forecast of $39.485 million.

SCE used 2009 recorded expenses as the base for its TY 2012 forecast and makes the various adjustments listed below:[924]

The first TY 2012 adjustment is an increase of $723,000 for customer growth of 1.83 % from 2009 to 2012.[925]

The second adjustment is an increase of $2.666 million to reflect the call volume growth that SCE expects to exceed customer growth. SCE states that its historical call volume from 2005 to 2009 is trending at a rate of 3.232% annually. SCE is forecasting an additional increase in call volume above the customer growth of 2% per year for TY 2012.[926]

The third adjustment is an increase of $3 million to reflect longer call handle times. SCE states that based on the historical average, its call handle time is increasing 1.7% annually. SCE states that factoring in the new inquiries related to rates, programs, and emerging markets, which are more complex transactions and will take longer to resolve, SCE forecasts that its average call handle time will increase to 2.1% annually when averaged from 2009 to 2012.[927]

---

[922] Ex. SCE-4, Vol. 2, p. 166.

[923] Ex. SCE-4, Vol. 2, p. 170.

[924] Ex. SCE-4, Vol. 2, p. 168.

[925] Ex. SCE-4, Vol. 2, p. 169.

[926] Ex. SCE-4, Vol. 2, pp. 169 to 170.

[927] Ex. SCE-4, Vol. 2, p. 170.

The fourth adjustment is an increase of $1.797 million for the competitive wage program to adjust the wages of CCO personnel to attract and retain qualified employees.[928]

The fifth adjustment is a decrease of $651,000 due to call deflection and productivity savings in the CCO as customers choose to communicate with SCE by means other than a phone call.[929]

DRA recommends the Commission use the 2009 recorded expenses of $39.485 million as the TY 2012 forecast.

First, DRA disputes SCE's TY 2012 adjustment of a $723,000 increase to reflect a cumulative customer growth of 1.83% for 2009 through 2012. SCE has not demonstrated that the expenses in FERC Account 903.800 are directly proportionate to the customer growth rate. The recorded expenses for FERC Account 903.800 were at the highest level of $40.108 million in 2008 but declined to $39.485 million in 2009 despite customer growth. The recorded expenses declined from 2008 to 2009 despite an increase in total customer contacts and an increase in transaction activity level of the CCO during this period.

Second, DRA disputes SCE's proposed $2.666 million increase to reflect the call volume growth that exceeds expected customer growth. SCE states that the call volume from 2005 to 2009 is trending at a rate of 3.232% annually. The numbers of inbound handled calls have increased since 2005, but the historical recorded costs for the CCO have decreased from $40.108 million in 2008 to $39.485 million in 2009. Some of the inbound calls can also be handled by CSBU's Interactive Voice Response System. Therefore, DRA recommends an adjustment of $2.666 million.

Third, DRA disputes SCE's proposed increase of $3 million to support longer call handle times. DRA reviewed SCE's average call handle times which shows that average has declined from 278 seconds in 2008, to 270 seconds in 2009. The recorded average handle times increased to 273 seconds or 1.1% from 2009 to 2010 which is still less than the 2.1% forecasted by SCE. Although recorded 2005 to 2008 average call handle times shows a steady increase, the average call handle times can also decrease as shown by the recorded 2008 to 2009 average call handle times.

---

[928] Ex. SCE-4, Vol. 2, p. 170.

[929] Id.

Fourth, DRA disputes SCE's proposed increase of $1.797 million for SCE's competitive wage program for the CCO. Any wage increases for CCO's personnel should be provided in the labor escalation as discussed in Section 14 of this Brief.

Fifth, DRA used the 2009 recorded expenses to forecast TY 2012 without reducing the forecast by the $651,000 due to call deflection in the CCO and productivity savings. DRA is recommending that the Commission *not* apply the $651,000 reduction. This will accommodate any increases in CCO expenses due to an increase in call volumes or longer call handle times.

For its 2013 forecast, SCE is requesting $48.462 million, an increase of $11.073 million above 2009 recorded expenses, for FERC Account 903.800.[930] DRA recommends a 2013 forecast of $38.095 million.[931]

SCE used 2009 recorded expenses as the base for the 2013 forecast and makes various adjustments discussed below.

The first 2013 forecast adjustment is a $1.390 million reduction due to implementation of the Edison SmartConnect program. In 2013, the CCO expects to receive fewer customer phone calls regarding inaccurate bills and service reconnection follow-up due to more timely and accurate services enabled by Edison SmartConnect.[932]

The second 2013 forecast adjustment is a $2.116 million increase to support increased customer call volume in the CCO for calls about service reconnection and new customer inquiries related to interval usage, web tools, more complex rates and other Edison SmartConnect related programs and services.[933]

The third 2013 forecast adjustment is an increase of $1.039 million for customer growth of 2.73% from 2009 to 2013.[934]

The fourth 2013 forecast adjustment is a $2.993 million increase to reflect the call volume growth that exceeds expected customer growth. SCE forecast an additional call volume above customer growth of 1.9% per year for 2013.[935]

---

[930] Ex. SCE-4, Vol. 2, p. 172.

[931] Ex. DRA-10, p. 43.

[932] Ex. SCE-4, Vol. 2, p. 171.

[933] Ex. SCE-4, Vol. 2, p. 171.

[934] Id.

[935] Ex. SCE-4, Vol. 2, p. 172.

The fifth 2013 forecast adjustment is a $3.282 million increase to reflect longer call handle times which SCE forecasts will increase annually at 1.8% when averaged from 2009 to 2013.[936]

The sixth 2013 forecast adjustment is an increase of $4.193 million for SCE's competitive wage program for CCO personnel.[937]

The seventh 2013 forecast adjustment is a decrease of $1.160 million due to call deflection and productivity savings in the CCO.[938]

DRA is recommending using the 2009 recorded expenses of $38.095 million as the forecast for 2013.

First, DRA accepts a decrease of $1.390 million due to the implementation of the Edison SmartConnect program to forecast 2013 expenses.

DRA disputes SCE's 2013 second, third, fourth, fifth and sixth adjustments for the reasons discussed above for the TY 2012 forecast.

DRA recommends that the Commission not apply the $1.160 million reduction adjustment to forecast 2013 expenses. This will accommodate any increases in CCO expenses due to an increase in call volumes or longer call handle times.[939]

6.2.4. FERC Account 905 – Miscellaneous Expenses

FERC Account 905 captures all of the Customer Accounts expense not reflected in or specific to the activities identified with FERC Accounts 901 through 904. This includes four specific activities: Account 905.100 includes all telephone expenses recorded by SCE's Call Centers; Account 905.300 includes all customer billing policy adjustments; Consumer Affairs expenses are recorded in Account 905.800; and Market Research expenses are recorded in Account 905.900.[940]

FERC Account 905 is disaggregated into four functional sub-accounts. The discussion that follows focuses on the accounts where DRA has differences with SCE's TY 2012 forecast and 2013 forecast.

---

[936] Id.

[937] Id.

[938] Id.

[939] Ex. DRA-10, p. 43.

[940] Ex. SCE-4, Vol. 2, p. 180.

6.2.4.1. FERC Sub-Account 905.300 – Policy Adjustments

FERC Sub-Account 905.300 records direct expenses associated with adjusting customer bills.[941] For SCE's 2012 "business as usual" forecast, and its 2013 forecast, SCE is requesting $726,000 which is a $200,000 increase from 2009 recorded expenses.[942]

SCE used 2009 recorded expenses as the base to forecast TY 2012 and 2013 forecast expenses.[943] SCE is requesting an increase of $200,000 in ratepayer funding for SCE's Service Guarantee program for missed appointments and timely and accurate first bills for both TY 2012 and 2013.[944]

DRA recommends the Commission use the 2009 recorded expenses of $526,000 for its forecast of both TY 2012 and 2013. Payments to customers to reimburse them for the inconvenience they have been caused by SCE not meeting its commitments should not be the responsibility of the very same SCE ratepayers who have no control over whether SCE meets its commitments or not. As the Commission found in SCE's last GRC, SCE shareholders should pay for the credits of the service guarantee programs.[945]

In Rebuttal, SCE argues that shareholders and ratepayers should "share" the cost of all service guarantee payments.[946] As support for this, SCE quibbles about whether timely and accurate billing, and meeting customer appointments on time are actually "*commitments*." SCE also says that when SCE misses appointments, "most of its customers" who receive the payment did not know the service guarantee was not met and/ or do no expect to receive the payment at all.[947]

SCE's first argument is a transparent attempt to change a policy that SCE dislikes for no good reason other than that SCE dislikes it. The second argument is completely unsubstantiated. Neither should be the basis of changing a carefully considered policy. DRA recommends that

---

[941] Ex. SCE 4, Vol., p. 188.

[942] Ex. SCE-4, Vol. 2, p. 191.

[943] Ex. SCE-4, Vol. 2, p. 194.

[944] Ex. SCE-4, Vol. 2, p. 191.

[945] D.09-03-025, p. 108.

[946] Ex. SCE-19, p. 67.

[947] Ex. SCE -19, p. 67.

the Commission use the 2009 recorded expenses of $526,000 for its forecast of both TY 2012 and 2013 expenses.

6.2.4.2. FERC Sub-Account 905.800 – Consumer Affairs

FERC Account 905.800 records the operations of SCE's Consumer Affairs which handles customer inquiries and complaints, and communicates and administers special programs and services for critical care, and disabled customers.[948]

For both its TY 2012 and 2013 forecasts, SCE is requesting $1.463 million, a $214,000 increase from 2009 recorded expenses. DRA is recommending $1.099 million for both years.

SCE used 2009 recorded expenses as the base to forecast TY 2012 and 2013 forecast expenses.[949] SCE is requesting an increase of $214,000 to support increased outreach efforts to special needs customers and to handle increased complaint volumes for both TY 2012 and 2013.[950]

DRA recommends using the five-year average of recorded expenses for the years 2005 to 2009. SCE's 2005 to 2009 recorded expenses show fluctuations. The recorded expenses were at a low of $998,000 in 2007, and a high of $1.249 million in 2009. The functions, such as the outreach to special needs customers and the handling of complaint volumes that are recorded in this account are activities SCE routinely performs. A five-year average provides an appropriate method to forecast TY 2012 and 2013 expenses for FERC Sub-Account 905.800.[951]

6.2.4.3. FERC Sub-Account 905.900 – Market Research & Communications

FERC Sub-Account 905.900 records the operations of SCE's Market Research and Communication functions which researches, collect, analyzes, and reports customer and industry information to develop and deliver programs, services and general information to customers.[952]

For its TY 2012 "business as usual" forecast, SCE is requesting $8.645 million, which is a $1.583 million increase from 2009 recorded expenses.[953] DRA recommends a TY 2012 forecast of $7.0 million.[954]

---

[948] Ex. SCE 4, Vol. p. 192.

[949] Ex. SCE-4, Vol. 2, p. 194.

[950] Ex. SCE-4, Vol. 2, p. 191.

[951] Ex. DRA-10, p. 47.

[952] Ex. SCE 4, Vol., p. 196.

SCE used 2009 recorded expenses as the base to forecast TY 2012 forecast expenses and added incremental adjustments for TY 2012.[955]

The first TY 2012 adjustment is an increase of $1.240 million to reflect the impact of Dynamic Pricing.[956]

The second TY 2012 adjustment is an increase of $151,000 for SCE.com web accessibility, including PDF remediation.[957]

The third TY 2012 adjustment is an increase of $150,000 to fund ongoing User Experience Enhancements to SCE.com to improve service capabilities on SCE.com for billing payment, and program enrollments; add new informational sections to address customer needs and interest, add more capabilities to keep customers informed through notifications and alerts; and a mobile web presence.[958]

The fourth TY 2012 adjustment is an increase of $42,000 to fund improved monitoring of the web site.[959]

First, for TY 2012, DRA recommends using the five-year average of recorded expenses (2005 to 2009) of $5.760 million as the forecast.

Second, DRA accepts SCE's request for a $1.240 million increase to reflect the Dynamic Pricing impact.

Third, DRA disputes SCE's proposed $150,000 increase to fund ongoing User Experience Enhancements to "SCE.com." SCE has embedded recorded costs during 2005 to 2009 to operate and update its website and has not shown why it should not receive additional funding.

Fourth, DRA disputes SCE's proposed $42,000 increase to fund improved monitoring of the web site. SCE has embedded recorded costs during 2005 to 2009 to operate and update its website and has not shown why it should receive additional funding.

---

[953] Ex. SCE-4, Vol. 2, p. 200.

[954] Ex. DRA-10, p. 50.

[955] Ex. SCE-4, Vol. 2, p. 198.

[956] Ex. SCE-4, Vol. 2, p. 199.

[957] Id.

[958] Ex. SCE-4, Vol. 2, p. 200.

[959] Id.

For 2013, SCE is requesting $10.091 million which is $3.029 million above 2009 recorded expenses for FERC Account 905.900. DRA recommends $7.0 million for 2013.[960]

SCE used 2009 recorded expenses as the base to forecast 2013 forecast expenses and then added incremental adjustments.[961]

The first 2013 forecast adjustment is a $603,000 increase to provide customer communications post-deployment of Edison SmartConnect operations. Of the $603,000, $518,000 is for the Dynamic Pricing efforts and $85,000 is included in the usage information and budget management tools efforts.[962]

The second 2013 forecast adjustment is an increase of $928,000 to enable customers to adopt and utilize energy usage information and budget management tools.[963]

The third 2013 forecast adjustment is an increase of $1.758 million to support the introduction of Dynamic Pricing rates.[964]

The fourth 2013 forecast adjustment is an increase of $151,000 for SCE.com web accessibility, including PDF remediation.[965]

The fifth 2013 forecast adjustment is an increase of $150,000 to fund ongoing User Experience Enhancements to SCE.com to improve service capabilities on SCE.com for billing payment, and program enrollments; add new informational sections to address customer needs and interest, add more capabilities to keep customers informed through notifications and alerts; and a mobile web presence.[966]

The sixth 2013 forecast adjustment is an increase of $42,000 to fund improved monitoring of the web site.[967]

For its forecast of 2013 expenses, DRA recommends using the five-year average of recorded expenses (2005 to 2009) of $5.760 million.

---

[960] Ex. DRA -10, p. 52.

[961] Ex.SCE-4, Vol. 2, p. 198.

[962] Ex. SCE-4, Vol. 2, p. 201.

[963] Id.

[964] Id at, p. 202.

[965] Id.

[966] Ex. SCE-4, Volume 2, p. 202.

[967]Id.

First, DRA disputes SCE's proposed $603,000 increase to provide customer communications post-deployment of Edison SmartConnect operations. SCE says "the impact of SmartConnect meters and their associated systems for ongoing operations will require changes to how we serve and communicate with our customers."[968] SCE has developed and implemented different programs to communicate with its customers over the years. The costs for education and outreach activities should be embedded in 2005 to 2009 recorded costs. SCE should not receive additional funding to communicate with its customers in addition to the requested funding for Dynamic Pricing.

Second, DRA disputes SCE's proposed increase of $928,000 to "enable customers to adopt and use energy usage information and budget management tools." Again, SCE has developed and implemented different programs to communicate with its customers over the years. The costs for education and outreach activities should be embedded in 2005 to 2009 recorded costs. The type of information that SCE communicates to its customers will change over time. SCE should not receive additional funding to communicate with its customers in addition to the requested funding for Dynamic Pricing.

Third, DRA accepts the increase of $1.240 million to support the introduction of the Dynamic Pricing.

Fourth, DRA disputes SCE's proposed increase of $151,000 for "SCE.com" web accessibility, including PDF remediation. SCE has embedded recorded costs during 2005 to 2009 to operate and update its website and has not shown why it should receive additional funding.

Fifth, DRA disputes SCE's proposed $150,000 increase to fund ongoing User Experience Enhancements to SCE.com. SCE has embedded recorded costs during 2005 to 2009 to operate and update its website and has not shown why it should receive additional funding.

Sixth, DRA disputes SCE's proposed $42,000 increase to fund improved monitoring of the web site. SCE has embedded recorded costs during 2005 to 2009 to operate and update its website and has not shown why it should receive additional funding.[969]

In Rebuttal, SCE criticizes DRA's recommendations regarding Dynamic Pricing outreach and education costs as unreasonable. In particular, SCE says it "requires" this funding "...to

---

[968] Id. at p. 201.

[969] Ex. DRA-10, pp. 52-53.

effectively communicate with and educate customers about time-variant pricing and perform outreach to those customers that will be most impacted by the new default Critical Peak Pricing (CPP) and mandatory Time of Use (TOU) rates."

SCE's arguments are based on dubious assumptions. First, just exactly *when* SCE customers will be impacted by Critical Peak Pricing (CPP) and mandatory Time of Use (TOU) rates is a subject of debate. SCE's Rate Design application is, as of this writing, at the pre-hearing conference phase. SCE's next Rate Design Window application is not expected until December 2012. Increasing SCE's revenue requirement, at ratepayer expense, to include customer outreach and education costs for a program whose parameters are completely unknown is unreasonable.

DRA also disagrees with SCE's statement that it needs increased funding to "*effectivel*y communicate with and educate customers..." It is not at all clear that SCE is "effectively" using the money its ratepayers already pay for customer outreach and communication.

If SCE's Rule 13.1 Notice to Customers is anything to go by, SCE is not communicating, or at least not *effectively,* now. SCE is required to provide a "Notice" to its customers of what they can expect as the effect on their rates if SCE's GRC application is adopted. As one of SCE's ratepayers noted at a Public Participation Hearing, SCE's Notice is useless on the subject.[970]

If SCE cannot communicate effectively on something as routine as a GRC application,[971] SCE has not justified making ratepayers fund any more of SCE's ineffective communications. Giving SCE more ratepayer money to continue its ineffective communications is an unreasonable waste of its ratepayers resources.

In the Commission's decision on PG&E's Rate Design Window Application, the Commission expressed concern about authorizing money for PG&E to education and perform outreach about dynamic pricing rates in a way that would *actually* be effective. The final decision included five orders with numerous subparts requiring PG&E to make certain showings

---

[970] 4 RT 315-318, PPH Visalia.

[971] See SCE Proof of Rule 13.1 Notice Requirements, 6/3/2011.

to demonstrate that it had used the funding *effectively*.[972] SCE has made no assurances of any kind here.[973] DRA continues to recommend $7.0 million for FERC Sub-Account 905.900.

6.2.5. FERC Account 586 – Meter Expense

6.2.5.1. FERC Sub-Account 586.400 – Test and Inspect Meters

FERC Account 586.400 captures all expenses related to the operation, inspection, and testing of meters and associated metering equipment.[974] For TY 2012, DRA recommends using 2009 recorded expenses of $9.856 million.

For its TY 2012 "business as usual" forecast, SCE is requesting $11.196 million, which is an increase of $1.340 million above 2009 recorded expenses for FERC Account 586.400.

SCE used 2009 recorded expenses and then added adjustments. The first TY 2012 adjustment is an increase of $180,000 for customer growth of 1.83% from 2009 to 2012.[975]

The second TY 2012 adjustment is an increase of $564,000 for the PEV program. The Meter Services Organization (MSO) expects an increase in meter installations related to the PEV program.[976]

The third TY 2012 adjustment is an increase of $596,000 for the HAN program. The MSO anticipates an increase in the number of meter testing and inspections as a result of the HAN-enabled customer devices that was not part of the SmartConnect deployment.[977]

DRA recommends the Commission adopt a forecast of $9.856 million. Of SCE's proposed adjustments, DRA disputes SCE's first increase of $180,000 for customer growth of 1.83% from 2009 to 2012. During 2005 to 2009, the recorded expenses declined from a high of $10.081 million in 2006 to a low of $8.940 million in 2008. The recorded expenses then increased to $9.856 million in 2009. Past recorded data shows no correlation between Test and Inspect meter expenses and customer growth.

Second, DRA disputes SCE's proposed $564,000 increase for the PEV program. At the end of 2010, SCE had 47 customers who have requested a second meter installation for PEV

---

[972] Decision on Peak Day Pricing for Pacific Gas & Electric Company (2010) D.10-02-032.

[973] 14 RT 2027-2029, Kiner/ SCE.

[974] Ex. SCE-4, Vol. 2, p. 215.

[975] Ex. SCE-4, Vol. 2, p. 219.

[976] Ex.SCE-4, Vol. p. 219.

[977] Id.

readiness.[978] There is no evidence that meter installations due to PEV readiness will be a significant factor in 2012.

Third, DRA disputes SCE's proposed $596,000 increase for the HAN program for the same reasons discussed above in connection with FERC Account 901.[979]

For 2013, SCE is requesting $11.334 million for FERC Account 586.400. DRA recommends 2013 expenses of $9.375 for 2013.[980]

SCE used 2009 recorded expenses and added adjustments to forecast 2013.

The first 2013 adjustment is a $1.828 million decrease due to the implementation of Edison SmartConnect.[981]

The second 2013 adjustment is a $1.079 million increases to support MSO operations post Edison SmartConnect deployment.[982]

The third 2013 adjustment is a $219,000 increase for customer growth of 2.73 % from 2009 to 2013.[983]

The fourth 2013 adjustment is an increase of $268,000 for the MSO Quality Management System.[984]

The fifth 2013 adjustment is an increase of $821,000 increase for the PEV program.[985]

The sixth 2013 adjustment is an increase of $919,000 for the HAN program. The MSO anticipates an increase in the number meter testing and inspections as a result of the HAN-enabled customer devices that was not part of the SmartConnect deployment.[986]

First, DRA accepts SCE's 2013 adjustment of a $1.828 million decrease due to the implementation of Edison SmartConnect.

Second, DRA accepts SCE's 2013 adjustment of a $1.079 million increase to support MSO operations post Edison SmartConnect deployment.

---

[978] Ex. DRA-10, p. 55, citing SCE's response to DRA-SCE-112-SWC, Q/A 1.a.

[979] Ex. DRA-10, p. 55.

[980] Ex. DRA-10, p. 57.

[981] Ex.SCE-4, Vol. 2, p. 220.

[982] Id.

[983] Id. at p. 221.

[984] Id.

[985] Id.

[986] Id.

Third, DRA disputes SCE's proposed $219,000 increase for customer growth of 2.73 % from 2009 to 2013. Past recorded data shows that recorded expenses have not been increasing despite recorded annual customer growth during 2005 to 2009.

Fourth, DRA accepts a $268,000 increase for the MSO Quality Management System.

Fifth, DRA disputes SCE's proposed $821,000 increase for the PEV program. At the end of 2010, SCE had 47 customers who have requested a second meter installation for PEV readiness.[987] SCE has not shown that meter installations due to PEV readiness will be a significant factor or cost in 2012.

Sixth, DRA disputes SCE's proposed $919,000 increase for the HAN program for the same reasons discussed in FERC Account 901.

6.2.6. FERC Account 587 – Customer Installation Expense

6.2.6.1. FERC Sub-Account 587.200 – Energy Theft

FERC Account 587.200 records all expenses for activities required to collect revenues that would otherwise be lost as a result of energy theft and billing exceptions caused by irregularities in meter registration.[988] SCE used 2009 recorded expenses and forecast $2.905 million for TY 2012 and then added one adjustment for 2013 for a total of $4.813 for that year.[989] DRA recommends $2.905 million for FERC Sub-Account 587.200 for each of the years 2012 and 2013.[990]

For 2013, SCE is requesting $4.813 million which is an increase of $1.908 million above 2009 recorded.

The $1.908 million increase SCE proposes for 2013 is due to the post-deployment operational requirements of the Edison SmartConnect program. The MSO Revenue Protection function expects that Edison SmartConnect meter installation will uncover additional energy theft and result in an increase in the number of investigations and meter tampering cases. SCE is requesting to add 22 FTEs and associated non-labor expenses.[991]

---

[987] Ex. DRA-10, p. 57, citing SCE's response to DRA-SCE-112-SWC, question 1.a.

[988] Ex.SCE-4, Vol. 2, p. 222.

[989] Id.

[990] Ex. DRA-10, p. 59.

[991] Id.

DRA is recommending a 2013 forecast of $2.905 million. DRA disputes SCE's proposed $1.908 million increase for SCE's assumption of additional energy theft cases. This assumption is speculative. SCE has not provided evidence that the SmartConnect system will detect an increase in the number of investigations and meter tampering cases. SCE's forecast is based on unsupported assumptions of an increase in investigations and meter tampering cases.[992] SCE has embedded recorded expenses for theft investigations. The number of revenue protection investigators/energy theft personnel has declined since 2007, and the current staffing is consistent with the average number of positions over the past five years. The current staff is adequate to address energy theft cases and SCE has not supported a need to increase current staffing.

6.3. Customer Service Expenses – Information Delivery

6.3.1. FERC Sub-Account 908.600 Customer Care – Account Management

FERC Account 908.600 captures all expenses for the Account Management organization. The Account Management function provides basic customer services to 689,000 non-residential service accounts that have more complex issues that cannot be practically addressed or resolved by simple phone communication or by mail.[993] SCE used 2009 recorded expenses and added the adjustments to forecast TY 2012 and 2013.[994]

For its TY 2012 "business as usual" forecast, SCE is requesting $15.534 million which is an increase of $894,000 above 2009 recorded expenses for FERC Account 908.600.[995] DRA recommends$15.079 million for TY 2012.

SCE used 2009 recorded expenses and added the adjustments to forecast TY 2012.

The first TY 2012 adjustment is an increase of $309,000 for three FTEs to support the PEV program.

The second TY 2012 adjustment is an increase of $439,000 for ten FTEs to support the anticipated increase in the number of inquiries by small, non-residential customers as Dynamic Pricing is implemented.

---

[992] Ex. DRA-10, p.60 citing SCE's response to DRA-SCE-52-SWC, Q/A 5.b.

[993] Ex. SCE-4, Vol. 3, p. 107.

[994] Id. at p. 108.

[995] Id. at p. 109

The third TY 2012 adjustment is an increase of $147,000 for two FTEs to support Outage Communications for large business and public agency customers.

DRA is recommending using the 2009 recorded expenses as the forecast TY 2012.

First, DRA disputes SCE's proposed increase of $309,000 to support the PEV program for the reasons stated above in connection with FERC Account 901.

Second, DRA is recommending the acceptance of an increase of $439,000 to support the Dynamic Pricing program.

Third, DRA disputes SCE's proposed increase of $147,000 to support Outage Communications for large business and public agency customers. Outage Communications should be a routine activity and should be embedded in recorded expenses. Also, the 2005 to 2009 recorded expenses show little fluctuation. DRA is recommending that SCE not receive additional funding for Outage Communication activities.[996]

For 2013, SCE is requesting $15.610 million which is an increase of $970,000 above 2009 recorded expenses for forecast 2013 for FERC Account 908.600. DRA recommends $15.079 million for 2013.

SCE used 2009 recorded expenses and added adjustments to forecast 2013.

The first 2013 forecast adjustment is an increase of $385,000 for four FTEs to support the PEV program.

The second 2013 forecast adjustment is an increase of $439,000 for ten FTEs to support the anticipated increase in the number of inquiries by small, non-residential customers as Dynamic Pricing is implemented.

The third 2013 forecast adjustment is an increase of $147,000 for two FTEs to support Outage Communications for large business and public agency customers.

DRA disagrees with SCE's proposed adjustments for the reasons set forth above in connection with the TY 2012 forecast for FERC Sub-Account 908.600.

6.3.2. FERC Sub-Account 908.610 – Customer Care – Energy Centers

FERC Account 908.610 captures all expenses for SCE's two Energy Centers.[997] SCE used 2009 recorded expenses and added one adjustment to forecast TY 2012 and 2013.[998] SCE

[996] Ex. DRA-10, p. 63.

[997] Ex. SCE-4, Vol. 3, p. 120.

[998] Id. at p. 122.

is requesting $2.110 million, an increase of $165,000 above 2009 recorded expenses, for TY 2012 for FERC Account 908.610.[999] SCE is requesting an increase of $165,000 for three additional employees to support the existing Energy Centers.[1000]

DRA is recommending $1.945 million for TY 2012 for FERC Account 908.610. DRA disputes SCE's proposed $165,000 for three additional employees to support the existing Energy Centers. SCE states that although labor and non-labor expenses fluctuated over the five year historical period, the last two years were comparable and reflected current operating requirements, as supplemental employees were replaced by full-time SCE positions.[1001] The five-year average of recorded expenses is $1.847 million which is close to the recorded expenses of $1.815 million in 2008 and $1.945 million in 2009. Therefore, DRA recommends using 2009 recorded expenses to forecast TY 2012.[1002]

For 2013, SCE is requesting $2.312 million which is an increase of $366,000 above 2009 recorded expenses for FERC Account 908.610.[1003] DRA is recommending $1.945 million for 2013.

SCE added two adjustments to 2009 recorded expenses. The first 2013 adjustment is an increase of $165,000 for three additional FTEs.[1004] The second is an increase of $202,000 for three additional FTEs for a third Energy Center.[1005]

DRA recommends the Commission use SCE's 2009 recorded expenses as its 2013 forecast. First, DRA disputes SCE's proposed increase of $165,000 for three additional FTEs at the existing Energy Centers for the same reasons as discussed above in connection with the TY 2012. Second, DRA disputes SCE's proposed increase of $202,000 for three additional FTEs for a third Energy Center. DRA is recommending no ratepayer funding for a third Energy Center. SCE has two Energy Centers called the Customer Technology Application Center (CTAC) and the Agricultural Technology Application Center (AGTAC). SCE states that the

---

[999] Id at p. 123.

[1000] Id.

[1001] Id. at p. 122.

[1002] Ex. DRA-10, p. 66.

[1003] Ex. SCE-4, Vol. 3, p. 124.

[1004] Ex. SCE-4, Vol. 3, p. 124.

[1005] Id.

seminar offerings at CTAC are in such high demand that frequently more than 50% of seminars have a waitlist.[1006] This information is based only on three months of data on CTAC's Seminars/Workshops for April to June 2010.[1007] A review of the CTAC waitlist shows that the actual numbers of people attending the seminars were less than the registered attendees.

A review of the 2005 to 2009 lists of AGTAC and CTAC seminars and workshops show Energy Center personnel participate in seminars and workshops at off-site locations such as the Black History Month and Asian Pacific American Heritage Month Events which contributed to the growth of seminar attendance since 2005. Also, the increased number of seminars and workshops offered at the Energy Center and at off-site locations such as community colleges and community centers contributed to the growth of seminar attendance since 2005.[1008]

SCE says it has considered alternatives to a third Energy Center such as web-based on-demand seminar presentment; "on location" seminars at various locations in SCE's service territory; and a mobile Energy Center. SCE is in the development stage to establish web based on-demand seminar presentment that will provide on-demand access to training and education for customers at their own convenience. SCE is considering expanding the "on location" seminars at various sites throughout SCE's service territory such as community colleges and community centers. The Mobile Energy Center could host seminars and workshops as well as house the necessary displays and equipment.[1009]

The existing two Energy Centers have made seminars and workshops available for SCE's customers through on-site and off-site locations. In addition, the alternatives considered by SCE will allow SCE to offer seminars and workshops to customers without the need for a third Energy Center. DRA recommends that funding for a third Energy Center not be authorized at ratepayer expense.

[1006] Ex. SCE-4, Vol 3, p. 49.

[1007] Ex. DRA-10, p. 66 citing SCE Workpapers to Exhibit SCE-4, Volume 3, Chapter I-III, pp. 155 to 156.

[1008] Ex. DRA-10, p. 67.

[1009] Ex. DRA-10, p. 67, citing SCE's response to DRA-SCE-70-SWC, questions 2.d.

6.3.3. FERC Sub-Account 908.640 – Customer Care – Account Management

FERC Account 908.640 captures all expenses for the Program Management function which researches, develops, manages, communicates, and measures customer care programs.[1010] SCE used 2009 recorded expenses and added adjustments to forecast TY 2012 and 2013.[1011]

For its TY 2012 "business as usual" forecast, SCE is requesting $14.262 million which is an increase of $5.648 million above 2009 recorded expenses for FERC Account 908.640.[1012] DRA is recommending $8.614 million for TY 2012.[1013]

SCE used 2009 recorded expenses as the base and added adjustments to forecast TY 2012 expenses.

The first TY 2012 adjustment is an increase of $155,000 for the SCE Energy Manager.[1014] SCE EnergyManager® is a suite comprised of both free and fee-based services that serves as the primary on-line delivery platform for energy information and tools for SCE's largest commercial and industrial customers.[1015]

The second TY 2012 adjustment is an increase of $2.160 million for the development, marketing, customer education and outreach of the Dynamic Pricing programs.[1016]

The third TY 2012 adjustment is an increase of $2.698 million for the PEV Program to market and communicate SCE PEV programs.[1017]

The fourth TY 2012 adjustment is an increase of $292,000 for program administration to support an anticipated increase in costs to administer the Medical Baseline program, and the Energy Assistance Fund.[1018]

The fifth 2012 adjustment is an increase of $343,000 for Web Accessibility, User Experience Enhancements, and SCE.com Monitoring activities.[1019]

[1010] Ex.SCE-4, Vol. 3, p. 111.

[1011] Id at p. 112.

[1012] Id. at p. 114.

[1013] Ex. DRA-10, p. 68.

[1014] Ex. SCE-4, Vol. 3, p. 113.

[1015] Ex SCE-4, Vol 2, p. 31.

[1016] Ex SCE-4, Vol. 3, p. 113.

[1017] Id. at p. 114.

[1018] Id.

DRA is recommending using 2009 recorded expenses as the forecast for TY 2012 expenses. A review of 2005 to 2009 recorded expenses shows that the five years of recorded expenses were at a relatively consistent level.

First, DRA disputes SCE's proposed $155,000 increase for the SCE EnergyManager®. SCE has embedded cost for SCE EnergyManager® which was launched in 2001. SCE has not shown why it should receive additional funding.

Second, DRA disputes SCE's proposed $2.160 million increase for the Dynamic Pricing programs. DRA recommended incremental funding in FERC Accounts 905.900 and 908.600 for SCE's Dynamic Pricing programs which should be sufficient for TY 2012 and 2013 to implement this program. As DRA discusses below in connection with SCE's Dynamic Pricing capital project, SCE has had minimal activity on this project which may indicate that Dynamic Pricing is more complicated than anticipated and those complications will impact SCE's implementation date of Dynamic Pricing.

Third, DRA disputes SCE's proposed $2.698 million increase for the PEV program's marketing and communication. DRA is recommending the disallowance of additional funding of the PEV program for the reasons stated above in connection with FERC Account 901.

Fourth, DRA disputes SCE's proposed increase of $292,000 for program administration to support an anticipated increase in costs to administer the Medical Baseline program, and the Energy Assistance Fund. The Medical Baseline program and the Energy Assistance Fund are existing programs with embedded recorded costs. Medical baseline applications and renewals process for 2006 to 2010 were at a high of 47,057 applications processed in 2009 but dropped to 44,946 applications processed in 2010. SCE has not shown why it should receive additional funding for these activities.[1020]

For 2013, SCE is requesting $16.435 million which is an increase of $7.821 million above 2009 recorded expenses for FERC Sub-Account 908.640.[1021] DRA recommends$9.750 million for 2013.[1022]

[1019] Id.

[1020] Ex. DRA-10, p. 70.

[1021] Ex.SCE-4, Vol. 3, p. 117.

[1022] Ex. DRA-10, p. 72.

SCE used 2009 recorded expenses as the base and added adjustments to forecast 2013 expenses.

The first 2013 forecast adjustment is an increase of $2.222 million for energy information and budget management tools comprised of $155,000 for SCE EnergyManager®, $1.136 million for Edison SmartConnect Enabled Energy Information and Budget Management Tools, and $931,000 for related marketing and communication efforts.[1023]

The second 2013 forecast adjustment is an increase of $860,000 for the SCE Dynamic Pricing programs.[1024]

The third 2013 forecast adjustment is an increase of $4.104 million to prepare customers for emerging markets and technologies comprised of $2.769 million for the PEV program and $1.335 million for the HAN program.[1025]

The fourth 2013 forecast adjustment is an increase of $292,000 for program administration to support an anticipated increase in costs to administer the Medical Baseline program, and the Energy Assistance Fund.[1026]

The fifth 2013 forecast adjustment is an increase of $343,000 for Web Accessibility, User Experience Enhancements, and SCE.com Monitoring activities.[1027]

DRA is recommending $9.750 million which is $6.685 million or 40.7 % less than SCE's 2013 forecast for FERC Account 908.640. DRA uses 2009 recorded expenses as a base to forecast 2013 expenses.

First, DRA accepts an increase of $1.136 million for Edison SmartConnect Enabled Energy Information and Budget Management Tools.

Second, DRA disputes SCE's proposed $155,000 adjustment for SCE EnergyManager® for the same reasons as above for TY 2012.

Third, DRA disputes SCE's proposed increase of $931,000 for Edison SmartConnect Enabled Energy Info related marketing and communication efforts. A review of 2005 to 2009 recorded expenses shows that the five years of recorded expenses were at a relatively consistent

---

[1023] Ex. SCE-4, Vol. 2, p. 115.

[1024] Ex. SCE-4, Vol. 3, p. 116.

[1025] Ex SCE-4, Vol. 3, p. 116.

[1026] Ex. SCE-4, Vol. 3, p. 116.

[1027] Ex. SCE-4, Vol. 3, p. 114.

level. The embedded recorded expenses include activities such as marketing and communication efforts. Different outreach and marketing campaigns occur throughout the years and are embedded in recorded expenses.

Fourth, DRA disputes SCE's proposed increase of $860,000 for Dynamic Pricing programs as discussed above in connection with TY 2012.

Fifth, DRA disputes SCE's proposed increase of $2.769 million for a PEV program for the same reasons as stated above in connection with FERC Account 901.

Sixth, DRA disputes SCE's proposed increase of $1.335 million for the HAN program for the same reasons as stated above in connection with FERC Account 901.

Seventh, DRA disputes SCE's proposed increase of $292,000 for Program Administration for Medical Baseline and Energy Assistance Fund for the same reasons as stated above for TY 2012.

Eighth, DRA disputes SCE's proposed increase of $343,000 for Web Accessibility, User Experience Enhancements, and SCE.com Monitoring for the same reasons as stated above for TY 2012.[1028]

6.3.4. FERC Sub-Account 916.600 – Customer Care – Program Management/ Rate Communications

FERC Account 916.600 captures all expenses for the Program Management function for Rate Communication activity.[1029] SCE expects to continue at the 2009 recorded expense level for TY 2012 and 2013.[1030]

DRA is recommending $630,000 which is $828,000 less than SCE's requests for TY 2012 and 2013 for FERC Account 916.600. DRA recommends using the five-year average of 2005 to 2009 recorded expenses to forecast TY 2012 and 2013 expenses. DRA's recommendation is $828,000 less than SCE's request for TY 2012 and 2013. The 2009 recorded expenses included additional expenses as a result of communication preparations to inform General Service (GS-1) customers about a shift in their rates from a flat energy charge to seasonal pricing in effective 2010.[1031] A breakdown of the recorded expenses shows that the

---

[1028] Ex. DRA-10, p. 72-73.

[1029] Ex SCE-4, Vol. 3, p. 117.

[1030] Ex SCE-4, Vol. 3, pp. 119 and 120.

[1031] Ex. SCE-4, Vol. 3, p. 119.

recorded labor expenses were relatively consistent for 2007 to 2009. The majority of the increase in 2009 was for customer communications including factsheets, brochures, and letters. DRA recommends using the five-year average of recorded expenses to forecast 2012 and 2013 expenses so that the effect of one-time events such as the GS-1 customer communication in 2009 can be lessened.[1032]

6.3.5. FERC Account 920 – Local Public Affairs

FERC Account 920 captures all expenses for the Local Public Affairs (LPA) function. SCE says its LPA function deals with (1) managing the licensing of new transmission and substation projects; (2) performing Public Involvement activities on new transmission, substation, subtransmission, and distribution licensing and construction projects; (3) encouraging energy efficiency programs by local and regional governments; and (4) local and regional governments in their capacities as regulators of the Company's operations at the local level, as intermediaries between the Company and end-use customers and as customers in their own right.[1033]

SCE is requesting $12.624 million which is $1.728 million above 2009 recorded expenses for the TY 2012 and 2013 forecasts for FERC Account 920.[1034] DRA recommends using a five-year average, or $9.297 million for TY 2012 and 2013 for FERC Account 920.[1035]

SCE used 2009 recorded expenses as the base and added two adjustments to forecast TY 2012 and 2013 expenses. The first adjustment is an increase of $1.151 million for an increase in public involvement and regional support.[1036] The second adjustment is an increase of $577,000 for project licensing support.[1037]

DRA recommends using the five-year average of 2005 to 2009 recorded expenses to forecast TY 2012 and 2013 expenses. DRA's recommendation is $3.327 million less than SCE's request. The recorded expenses show fluctuations from a low of $8.422 million in 2006 to a high of $10.896 million in 2009. SCE provides examples of LPA work regarding major

---

[1032] Ex. DRA-10, p. 75.

[1033] Ex. SCE-4, Vol 3, p. 135

[1034] Id. at p. 138

[1035] Ex. DRA-10, p. 78.

[1036] Ex. SCE-4, Vol. 3, p. 138

[1037] Ex. SCE-4, Vol. 3, p. 139

transmission line relocations that SCE says will increase LPA's workload. However, some of these projects are projects have been ongoing since 2005. For example, SCE has been participating in the I-710 Freeway Expansion since 2007; the potential need for a new 500kV line from the Hinson to Mesa substations since 2008; and the planning of the Renewable Energy Initiative (RETI) since 2007.[1038] Also, the number of major transmission and substation projects that involve LPA increased from one in 2005 to twelve in 2009. Therefore, the historical recorded expenses provide a good indication of the LPA activity level in 2012 and 2013.[1039]

6.4. Customer Service Expenses – Service Fees

DRA has no comment on this issue at this time.

6.5. Customer Service Expenses – Other Operating Revenue

SCE is forecasting $37.783 million in TY 2012 for Other Operating Revenues (OOR) for Customer Service Operations based on SCE's proposed service fees, compared to $59.014 million per year based on the fees authorized in its 2009 GRC. SCE states that the proposed decrease in OOR is primarily the result of the Edison SmartConnect system's capability to remotely disconnect and reconnect electric service for most residential customers which eliminates the need for a field visit in most instances.[1040] SCE states that the field visit/service order is a major component of the present day cost to provide new service connections, service transfers, and credit related disconnections and reconnections. The costs and cost savings that result from the use of the RSS affect FERC Accounts 451.200 through 451.600.[1041]

DRA is recommending a forecast of $43.091 million of CSBU OOR which is $5.308 million or 14 % above SCE's forecast for CSBU OOR for TY 2012. DRA does not oppose SCE's proposed decrease in OOR as a result of the Edison SmartConnect system's capability to remotely disconnect and reconnect electric service for most residential customers which eliminates the need for a field visit in most instances.

In order for SCE's new proposed service fee rates to be effective, the Commission's 2012 GRC decision needs to authorize the new service fees. The 2006 GRC decision was adopted on

---

[1038] Ex. DRA-10, p. 78 citing SCE's response to DRA-SCE-73-SWC,Q/A 1 and 2

[1039] Ex. DRA-10, p. 78.

[1040] Ex. SCE-4, Vol. 4, p. 89.

[1041] Ex. SCE-4, Vol. 4, pp. 91 to 92.

May 11, 2006 and the 2009 GRC decision was adopted on March 12, 2009. Based on the adoption dates of the 2006 GRC and the 2009 GRC, DRA anticipates that the Commission will not likely adopt a decision for the 2012 GRC before the first quarter of 2012. Until the Commission adopts the 2012 GRC decision, SCE will be charging service fees authorized from the 2009 GRC decision.

The 2012 OOR forecast based on the currently authorized fees will remain in effect for the first quarter of 2012 and SCE will collect service fees based on these currently authorized fees. DRA forecasts that SCE will collect 25 % of SCE's 2012 OOR forecast based on the currently authorized fees during the first quarter of 2012 and that SCE will collect 75 % of SCE's 2012 OOR forecast based on SCE's proposed service fees at the lower rates during the remaining three quarters of 2012. Therefore, DRA is recommending a forecast of $43.091 million of CSBU OOR for TY 2012.[1042]

CSBU Other Operating Revenues TY 2012 forecast also includes "gains/losses on sale of property."[1043] SCE states that the gains and losses on minor sales of property are allocated between customers and shareholders pursuant to Commission policy. The sales are for non-operating property originating in FERC Accounts 101 or 105 and transferred to FERC Account 121 prior to sale. Gains and losses on major sales such as divestiture of power plants and the sale of Edison Pipeline & Terminal Company facilities are treated individually at the Commission and are not included in the 2012 GRC filing. The allocation of the gains and losses on the sales included in the 2012 GRC filing are based on a two step process: (1) the amount of time the property was included in rate base; and (2) whether or not the property was depreciable.[1044]

SCE is forecasting $713,000 of gains on minor sales of property for TY 2012. SCE proposes to use a three-year recorded average to estimate annual customer gains/losses.

DRA is forecasting $1.788 million of gains on minor sales of property for TY 2012 which is $1.075 million above SCE's forecast. DRA proposes using a five-year recorded

---

[1042] Ex. DRA-10, p. 93-94.

[1043] Ex. SCE-10, Vol. 2, p. 17.

[1044] Ex. SCE-10, Vol. 2, p. 17.

average to estimate annual customer gains/losses. DRA's recommendation is consistent with SCE recorded gains on minor sales of property of $1.706 million in 2009.[1045]

6.6. Customer Service Capital – Structures and Improvements

CSBU's capital expenditure forecast includes the capital needs of the Meter Services, Energy Center, Call Center, Revenue Services, and Business Customer Division. CSBU is also requesting eight capitalized software projects.[1046]

SCE requests $69.824 million in 2010, $72.744 million in 2011, and $75.141 million in TY 2012.[1047] DRA recommends $50.768 million for 2010, $40.159 million in 2011, and $37.462 million in 2012 for CSBU capital expenditures.

SCE includes forecasts for CSBU capital expenditures from 2010 through 2014. Consistent with the Commission's decision in D.09-03-025 rejecting budget-based forecasts for post-test years,[1048] DRA addresses each category of capital expenditures SCE forecasted for 2010 to 2012 where DRA disagrees with SCE. DRA addresses capital expenditure issues for 2013 and 2014 in Section 16 of this Brief.

SCE is requesting $2.125 million in 2010, $1.295 million in 2011, and $5.735 million in 2012 for capital expenditures for Structure and Improvements.[1049] SCE is requesting $3.5 million in 2012 to establish a third Energy Center, either in Orange County or in an eastern SCE service region.[1050] The remainder of the 2012 capital expenditures request is to upgrade and retrofit projects for the existing two Energy Centers.

DRA is recommending $2.931 million in 2010, $1.295 million in 2011, and $2.235 million in 2012 for capital expenditures of Structures and Improvements. DRA is recommending the 2010 recorded capital expenditures for Structures and Improvements. DRA accepts the $1.295 million as requested by SCE for 2011.

[1045] Ex. DRA-10, p. 97.

[1046] Ex. SCE-4, Vol. 4, p. 1; Ex. DRA-10, p. 79 citing SCE Workpapers to Exhibit SCE-4, Volume 4, Chapter III, pp. 12, 229, 233, 234, 235, 283, 289, 312, 319, and 389.

[1047] Ex. SCE-4, Vol. 4, p. 3.

[1048] D.09-03-025, mimeo, p. 304.

[1049] Ex.SCE-4, Vol. 4, p. 4.

[1050] Ex.SCE-4, Vol. 4, p. 5.

DRA disputes SCE's proposed request of $3.50 million in 2012 to establish a third Energy Center. As discussed above in connection with FERC Account 908.610, DRA concludes that the existing two Energy Centers have made seminars and workshops available for SCE's customers through on-site and off-site locations. Also, DRA concludes that the alternatives considered by SCE will allow SCE to offer seminars and workshops to customers without burdening ratepayers with the costs of a third Energy Center.[1051]

6.7. Customer Service Capital – Furniture and Equipment

SCE is requesting $4.699 million in 2010, $4.527 million in 2011, and $2.100 million in 2012.[1052] SCE's forecast was developed based on expected furniture and equipment needs for employee growth, forecast remodels of SCE buildings that contain CSBU employees, expected ergonomic furniture needs by CSBU employees, and an assessment of the condition of existing furniture and equipment.[1053]

DRA is recommending $671,000 in 2010, $752,000 in 2011, and $752,000 in 2012 for capital expenditures of office furniture and equipment. DRA used SCE's 2010 recorded capital expenditures of $671,000 for office furniture and equipment for 2010. DRA used the 2005 to 2009 five-year average of capital expenditures for office furniture and equipment of $752,000 to forecast 2011 and 2012 capital expenditures which is consistent with SCE's 2010 recorded capital expenditures of $671,000 for office furniture and equipment.

6.8. Customer Service Capital – Specialized Equipment

DRA has no comment on this issue at this time.

6.9. Customer Service Capital – Meters and Advanced Metering

SCE is requesting $25.657 million 2010, $24.310 million in 2011, and $23.321 million in 2012.[1054] DRA is recommending $15.552 million for 2010, $11.90 million for 2011, and $8.50 million in 2012 for meter capital expenditures.[1055]

[1051] Ex. DRA-10, p. 81.

[1052] Ex. SCE-4, Vol. 4, p. 7.

[1053] Ex. SCE-4, Vol. 4, p. 6.

[1054] Ex.SCE-4, Vol. 4, p. 11.

[1055] Ex. DRA-10, p. 84.

SCE states that its metering capital estimates for the 2009 GRC period (2009 to 2011) were forecasted under the "business as usual" assumption (i.e. without Edison SmartConnect). SCE forecasted the 2012 meter capital expenditure estimates based on business as usual.[1056] The 2010 to 2012 forecast for meter capital are based on the quantities of the historical new growth installation rates and the historical replacement rates of legacy electromechanical meters installed prior to the SmartConnect deployment.[1057]

SCE continues to install legacy meters during the SmartConnect deployment period for the following reasons:

- There are SCE districts (geographic areas) where the SmartConnect meter and communication network have not yet been deployed and the SmartConnect communication system is not yet functional.
- In cases where a customer chooses to go on a time-of-use (TOU) rate in an area where the Edison SmartConnect communication is not yet functional, the ability to obtain TOU data through the Meter Data Management System has not yet been established and the only alternative for obtaining TOU data is through the established legacy metering processes.
- For the small percentage of accounts for which the Edison SmartConnect meter form is not yet available.[1058]

The revenue requirement for the Edison SmartConnect metering capital additions is being recovered through the Edison SmartConnect Balancing Account.[1059] SCE states that the 2012 capital revenue requirement associated with the Edison SmartConnect meters should continue to be recovered through the ESCBA to be consistent with the Edison SmartConnect Settlement Agreement adopted in D.08-09-039.

SCE states that, to avoid double recovery and consistent with D.08-09-039, SCE's approach is to return the incremental capital benefits to ratepayers, as SCE will not have to install legacy meters (because Edison SmartConnect meters are being used instead). As Edison SmartConnect meters are being installed, these capital benefits are passed through to ratepayers through the Base Revenue Requirement Balancing Account (BRRBA) and include the elimination of routine legacy meter replacements as well as safety access and leased meter

---

[1056] Ex. SCE-4, Vol. 4, p. 10.

[1057] Ex. SCE-4, Vol. 4, p. 10.

[1058] Ex. DRA-10, p. 83, citing SCE's response to DRA-SCE-193-SWC, Q/A 7.

[1059] Ex. SCE-4, Vol. 4, p. 9.

installations. SCE forecasts capital benefits of $1.6 million in 2010 and $5.1 million in 2011. SCE is also forecasting $8.5 million in meter capital benefits in 2012.[1060]

SCE had recorded meter capital expenditures of $17.152 million for 2010 (SmartConnect capital benefits have not been deducted). DRA is recommending $15.552 million for 2010 meter capital expenditures by accepting SCE's recorded meter capital expenditures of $17.152 million for 2010 and reducing it by the Edison SmartConnect capital benefits of $1.6 million.

To forecast SCE's meter capital expenditures for 2011 and 2012, DRA reduced the 2010 recorded capital expenditures of $17 million by the Edison SmartConnect capital benefits of $5.1 million for 2011 and $8.5 million for 2012.[1061]

During 2010 to 2012, SCE is receiving capital-related revenue requirement for electromechanical (legacy) meters recovered through the "business as usual" GRC forecast as well as receiving capital-related revenue requirement for SmartConnect meters recovered through the ESCBA. First, DRA takes into account the fact that some legacy meters can be re-used and eliminates the need to purchase new legacy meters during 2010 to 2012. SCE itself states:

> "Some legacy meters could be reused for routine legacy meter growth and replacement during 2009 to 2012. However, SCE is using new or recycled meters from existing meter inventory for routine legacy meter growth and replacement, and is salvaging the meters that are being replaced by Edison SmartConnect meters…All newly purchased legacy meters are placed in the legacy meter inventory and all new and replacement legacy meters come out of existing inventory. SCE does not track how many of the 25,636 legacy meters installed for routine customer growth in 2010 or the 55,921 legacy meters installed for routine replacement in 2010 were newly purchased or how many came from the existing meter inventory. Existing legacy meter inventory includes some reused meters; however, none of the legacy replaced with Edison SmartConnect meters are returned to the existing meter inventory. The existing legacy meter inventory is being depleted as the Edison SmartConnect deployment process continues."[1062]

Second, SCE provided the invoices to support approximately $2.349 million or 15 % of the $15.952 million of the routine legacy meter costs recorded in 2010.[1063] SCE claims that it

---

[1060] Ex. SCE-4, Vol. 4, p. 11.

[1061] Ex. DRA-10, p. 85.

[1062] Ex. DRA-10, p. 86, citing SCE's response to DRA-SCE-224-SWC, Q/A 1.a. and 1.d.

[1063] Ex. DRA-10, p. 86.

does not track how many of the 25,636 legacy meters installed for routine customer growth in 2010 or the 55,921 legacy meters installed for routine replacement in 2010 were newly purchased or how many came from the existing meter inventory. DRA continues to recommend the Commission adopt a forecast of $15.552 million for 2010, $11.90 million for 2011, and $8.50 million in 2012 for meter capital expenditures.[1064]

6.10. Customer Service Capital – Capitalized Software Projects

SCE is requesting $33.883 million in 2010, $41.400 million in 2011, and $43.010 million in 2012, $50.646 million in 2013, and $31.876 million in 2014 for a total of $200.815 million for CSBU capitalized software projects.[1065] SCE is proposing the following CSBU Capital System Projects:

- Alerts and Notifications
- Interactive Voice Response-Advanced Speech Recognition
- Customer Relationship Management
- Enhanced Meter and Usage Capabilities
- HAN Support and Troubleshooting; and
- Plug-in Electric Vehicles

DRA is recommending $25.313 million in 2010, $25 million in 2011, and $25 million 2012 for capital expenditures of capitalized software. DRA is recommending $25.313 million for 2010 capital expenditures for CSBU capitalized software projects based on SCE's 2010 recorded capitalized software expenditures. SCE recorded 74 % of its forecasted capital expenditures for 2010. DRA recommends using the 2010 recorded capital expenditures for capitalized software projects to forecast 2011 and 2012 capital expenditures.[1066]

DRA's recommendation for the 2011 and 2012 forecasts of capitalized software projects is based on DRA's review of some of SCE's proposed capitalized software projects. Also, some of SCE's proposed capitalized software projects are the result of the Edison SmartConnect

---

[1064] Ex. DRA-10, p. 87.

[1065] Ex. DRA-10, p. 86, citing SCE Workpapers to Exhibit SCE-4, Volume 4, Chapter III, pp. 12, 229, 233, 234, 235, 283, 289, 312, 319, and 389.

[1066] Ex. DRA-10, p. 86.

program and SCE has spent approximately 42 % of the total authorized funding for the Edison SmartConnect program as of December 31, 2010.[1067]

DRA discusses the capitalized software projects that DRA has differences with SCE below. Although DRA does not discuss some of CSBU's capitalized software projects requested in 2011 and 2012, this does not necessarily mean that DRA approves of those capital projects.

6.10.1. Alerts and Notification

DRA disputes SCE's Alerts and Notifications project. SCE is requesting $9.330 million in 2012 for the project. SCE claims that the Alerts and Notifications project will automate the delivery of information to help customers manage their bills and payments; prepare for planned outages; and adopt a smart energy lifestyle through Dynamic Pricing, demand response and energy efficiency programs.[1068] SCE claims that its customer base is becoming more dependent on electronic means of information exchange with SCE and that this project will implement an integrated, automated method for SCE to send electronic communications to customer through various channels, one-way or two-way (e.g. inbound response or inquiry from customers). SCE states that its current system of electronic alerts and notifications meets its regulatory or business requirements today but wants a more effective approach.[1069]

Currently, SCE has the following Alerts and Notification systems:

- The Varolii/Outage Notification Communications (ONC) system which is an in-house application that SCE developed with the Varolii Corporation. The messages can be delivered by email, voice, pager/Short Message Service (SMS) and fax. This system manages the event notifications for Demand Bidding Program, Critical Peak Pricing Program, Base Interruptible Program, and Agricultural Pumping and Interruptible Program. This system also sends messages to customer groups that are notified of rotating outages such as medical baseline customers, public affairs stakeholders, major customers with demand greater than 300 kW, subtransmission customers, and qualified net generator customers. The Varolii/ONC system was implemented in 2008 as a component of the Demand Bidding program for the Advanced Metering OIR. This system cost $321,000 in 2003 for the initial implementation and an additional $209,000 in upgrades during subsequent years. The annual vendor service contract is estimated to be $182,500.

[1067] Ex. DRA-10, p. 88 citing Edison SmartConnect, Quarter Program Update, March 25, 2011, p. 6 which shows that SCE spent $690 million of the $1.634 billion authorized in D.08-09-039.

[1068] Ex. SCE-4, Vol. 4, p. 20.

[1069] Ex. SCE-4, Vol. 4, p. 20.

- First Call is an outsourced vendor service that is the backup to Varolii/ONC system in case of system failure since 2001 on an as-needed basis. This system has email, pager, and text capabilities.
- SCE.com has an application within MyAccount capability to notify customers when their bill is ready and when their payment has been received. There is a plan to expand it to include Unplanned Outage Notification in 2011 for business customers only. The "Bill-ready" notification was implemented in 2004 as part of the SCE.com MyAccount redesign effort and costs $1 million. The "Payment Received" notification was implemented in 2009 and cost $719,000 in 2009.
- The Interactive Voice Response (IVR) has been integrated with the Customer Service System (CSS) to facilitate outbound calls for credit collections. The IVR is also integrated with the CSS which receives information from the Outage Management System to facilitate outbound calls for power outage status and outage restoration. The IVR system tracks planned outage schedules and manages communication to customers including post cards, in-field communication door hangers, day-before reminder and cancellation calls. The IVR system was first implemented in 1995 at an approximate cost of $177,000 and has been upgraded through the years.[1070]

SCE states that it is currently "...using some electronic alerts and notifications. These systems have been built over time to support existing programs and services. However, because the systems were created separately and at different times, for various purposes, little coordination occurs between these systems today. Current systems are not integrated or scalable for the volume of electronic alerts and notifications expected in the near future, and may not support new technologies such as SMS texting."[1071]

SCE has not performed any studies or analyses on the current systems managing alerts and notifications to support this statement.[1072] SCE's current systems meet SCE's regulatory or business requirements today. SCE is speculating that its current systems cannot handle future needs without any analyses on its current systems. The Varolii/ONC system since 2003, the SCE.com since 2004, and the IVR since 1995 have performed the electronic alerts and notifications requirements. SCE has not justified its request for $9.330 million in 2012 for the Alerts and Notifications project.[1073]

[1070] Ex. DRA-10, p. 90, citing SCE's response to DRA-SCE-92-SWC, Q/A 1.a. to 1.c.

[1071] Ex. SCE-4, Vol. 4, p. 20.

[1072] Ex. DRA-10, p. 90, citing SCE's response to DRA-SCE-92-SWC, Q/A 1.d.

[1073] Ex. DRA-10, p. 88-90.

6.10.2. Dynamic Pricing Project

DRA is recommending the recorded capital expenditures of $55,000 for 2010 for the Dynamic Pricing Project. SCE forecasted $3.730 million in 2010 for the Dynamic Pricing Project. SCE is requesting $17 million in 2011 and $16 million in 2012 for this project.

DRA recommends no funding in 2011 and 2012 for the Dynamic Pricing capital project. SCE has no support for SCE's request for $17 million in 2011 and $16 million in 2012. SCE has not issued any Request for Proposals as of January 2011 to external vendors or worked with external vendor to perform work for the Dynamic Pricing project in 2010.[1074]

In its Rebuttal testimony, SCE says "DRA's recommendations are contrary to CPUC requirements in D.09-08-028."[1075] DRA disagrees. DRA's recommendations are consistent with the activity to date in SCE's dynamic pricing proceedings, which have been delayed and do not, to DRA's knowledge, have any anticipated decision date.

In Rebuttal, SCE also says that "[i]n the end, the implementation date delay will not have a significant impact on SCE's cost forecast. For example, SCE needs to develop, implement and test the systems needed for an anticipated October 2012 implementation date. However, if the implementation date is delayed to early 2013, the costs related to development, implementation and testing will still need to be incurred with this GRC cycle."[1076] DRA disagrees. As noted above, there is no assurance that there will be an implementation date in October 2012 or "early 2013." Moreover, if the scope of the implementation is changed, as it has changed in the case of PG&E's ratepayers, that could have a significant impact on costs. Without knowing when the program is going to be implemented, or how, SCE's forecast is unreliable.

6.10.3. Home Area Network and Troubleshooting Project

SCE is requesting $8.3 million in capital expenditures for the HAN project in 2012. SCE states that the focus of this project is two-fold. First, this project will be delivered as part of SCE's Edison SmartConnect project. Second, this project will design and implement new system functionality that was not envisioned at the time of the Edison SmartConnect business case.[1077]

[1074] Ex. DRA-10, p. 91, citing SCE's response to DRA-SCE-96-SWC, Q/A 1.c. and 1.d.

[1075] Ex. SCE-19, p. 17.

[1076] Ex. SCE-19, p. 18.

[1077] Ex.SCE-4, Vol. 4, p. 54.

DRA disputes the $8.3 million in capital expenditures for the HAN project in 2012 and recommends no ratepayer funding. DRA is recommending no HAN expenses because SCE states that the implementation of the PCT program has been postponed due to an unanticipated delay in the Advanced Load Control System (ALCS) technology, and the provisions of IHDs, which has been postponed due to a delay in the adoption of the Smart Energy Profile 2.0 HAN national standard.[1078] SCE has proposed to modify ESCBA so that costs authorized in D.08-09-039 for HAN functionalities related to the PCT program remain in operation for purposes of recording authorized costs through 2014 because these costs are expected to be incurred in 2013 and 2014. SCE states that the implementation of the PCT program has been postponed due to an unanticipated delay in the Advanced Load Control System (ALCS) technology, and the provisions of IHDs, which has been postponed due to a delay in the adoption of the Smart Energy Profile 2.0 HAN national standard (see DRA's discussion above in connection with FERC Account 901).[1079]

6.10.4. Plug In Vehicles Support Systems

SCE is requesting $2.0 million of capital expenditures for the PEV project in 2012. SCE states that to support the forecasted enrollment rates for PEVs, SCE claims it must make upgrades to SCE.com, Electric Service Planning's Design Manager System, and MSO's Field Automated Test System.[1080]

DRA disputes the $2.0 million of capital expenditures for the PEV project in 2012. DRA's discussion for FERC Account 901 discusses DRA's reasons for objecting to SCE's requested PEV costs. For example, based on the 100 PEVs in SCE's service area as of February 2011, DRA concludes that SCE's forecast of 21,090 PEVs in its service area by the end of 2012 is unlikely. Also, SCE already has embedded costs for PEV Readiness recorded in 2009.

7. Information Technology and Business Integration

DRA reviewed SCE's Information Technology and Business Integration (IT&BI) testimony and makes recommendations in the following areas: (1) Market Redesign and

[1078] Ex. SCE-4, Vol. 1, p. 30.

[1079] Ex. SCE-4, Vol. 1, p. 30

[1080] Ex. SCE-4, Vol. 4, p. 64

Technology Update (MRTU) (2) Information Technology Expense and (3) Capital Expenditure Forecast[1081].

In addition to the foregoing categories, while reviewing the IT&BI testimony and in examining the IT&BI witnesses, DRA found that SCE comingled non-labor expenses and contingent or consultants expenses, thereby grossly distorting the operations and maintenance (O&M) costs of the IT&BI division[1082]. DRA addresses SCE's comingling of expenses in FERC 923 and FERC 921 under IT&BI. The established ratio of permanent workers to contingent workers in the section was 50:50 and the number of workers was about 1,600. The unknown impact of this arbitrary misuse of both FERC accounts on authorized revenue for IT&BI is likely to be significant.

> **921 Office supplies and expenses**.
>
> A. This account shall include office supplies and expenses incurred in connection with the general administration of the utility's operations which are assignable to specific administrative or general departments and are not specifically provided for in other accounts. This includes the expenses of the various administrative and general departments, the salaries and wages of which are includible in account 920.
>
> B. This account may be subdivided in accordance with a classification appropriate to the departmental or other functional organization of the utility.
>
> **923 Outside services employed**.
>
> A. This account shall include the fees and expenses of professional consultants and others for general services which are not applicable to a particular operating function or to other accounts. It shall include also the pay and expenses of persons engaged for a special or temporary administrative or general purpose in circumstances where the person so engaged is not considered as an employee of the utility.
>
> B. This account shall be so maintained as to permit ready summarization according to the nature of service and the person furnishing the same.[1083]

[1081] For the most part these categories track the briefing outline on a very general level, where IT&BI Expenses cover Application Services, Technology and Risk Management, Infrastructure Operations and Business Operations Management under one heading.

[1082] It eventually emerged that this commingling of FERC 921 and 923 accounts occurred throughout the GRC.

[1083] Ex. DRA-46, Accounting and Reporting Requirements for Public Utilities and Licenses.

Clearly, non-labor expenses are required to be recorded in FERC 921 account, while contingent worker and consultants' expenses are supposed to be recorded in FERC 923 account. However, SCE decided to transfer contingent worker expenses from FERC 923 account to FERC 921 account[1084] because the contingent workers were more like SCE's permanent employees since they do the same work[1085].

> Q. You found that the contingent workers are more like 920 employees because they do the same work?
>
> A. Correct.
>
> Q. But you took the contingent workers and put [them] in 921, which [is] nonlabor costs, instead of 920, which is labor cost[1086]?
> A. The FERC guidelines call for the labor cost of your employees to be in 920 and all the nonlabor costs to be in 921. That's why when we talk about 920 and 921 we always talk about them together.

On further examination, SCE's witness on this issue had even more justifications for putting contingent worker expenses in FERC 921 accounts instead of FERC 923.

> Q. Let me see if I got this right. The sole purpose of your decision to move contingent and supplemental workers into 921 was because they more appropriately match the work done by employees in 920; is that correct?
>
> A. That, and the FERC account guidelines call for expenses in 921 to be the expenses associated with the work being done in 920.[1087]

It is difficult to see how FERC 921 and 923 accounts could state their purposes any clearer. The title for FERC 921 account is "office supplies and expenses", which to a reasonable person would seem to suggest those expenses used to run the office, but SCE maintains that the word "expenses" as used in the title means "contingent" workers[1088]. Similarly, the title of FERC 923 account is "Outside Services Employed" but SCE's witness Mr. Huson claims that "outside

---

[1084] 15 RT 2147:19 - 28, Huson/ SCE.

[1085] 15 RT 2159:12 – 2160:21, Huson/SCE.

[1086] See also 20 RT 3285, testimony of Kevin Cini indicating that SCE characterized "contingent workers" as "labor" in the workpapers submitted with the Power Procurement and Business Unit testimony.

[1087]

[1088] 15 RT 2162:4-7, Huson/ SCE.

services" refer only to "consultants" not "contingent workers"[1089], even though contingent workers were employed from outside SCE through agencies and are not on SCE's payroll[1090]. When confronted with the sentence in FERC 923 that says the "account shall include the fees and expenses of professional consultants and others …" and the following exchange took place:

> Q. What is it [FERC 923] referring to as "others"?
>
> A. I don't know. I guess I focus in on the professional consultant, and then coming down to the items, it provides further descriptions of what those would be...[1091]

SCE has chosen to violate a uniform accounting rule that has significant impact on ratepayer costs without seeking or obtaining appropriate legal advice on the interpretation of the rule. Yet, SCE seeks to add more and more attorneys and legal consultants in every GRC.

Further, IT&BI did record some consultant expenses in FERC 923 account and entered those in the work papers, but in the end SCE decided to merge those "consultant" expenses into FERC 921 account as well[1092]. The notion that FERC guidelines leave it to the utilities' discretion to put a category of expenses wherever the utility wants defeats the very purpose of having a uniform set of accounting rules for utilities in the first place. Both FERC 921 and 923 use a clear mandatory directive, "shall" in stating how the utilities must record their expenses[1093].

If SCE actually merged FERC 921 and 923 accounts for legitimate purposes, SCE would have included an explanation of why it did so, in a transparent manner, with its opening testimony. Instead SCE submitted its IT&BI testimony with only entries for FERC 920 and 921 accounts, but nothing on FERC 923. Similarly if the impact of this change were significant SCE would not have some to such grat lengths to justify it.

SCE's unauthorized practice of merging FERC 921 and 923 accounts probably has significant hidden costs for ratepayers that cannot be examined in this GRC. For one thing,

---

[1089] 15 RT 2162:11 – 2163:14, Huson/ SCE.

[1090] 23 RT 3851:7 – 9, Miller/ SCE.

[1091] 15 RT 2164:5-10, Huson/ SCE.

[1092] 15 RT 2157:22 – 2158:12, Huson/ SCE.

[1093] When confronted with the interpretation of the statute, Mr. Huson argued that the language of the FERC rule he used was different from the document used to examine him in the hearing room, because apparently there is additional language in the rule he read. However, after a break, Mr. Huson returned to say he agreed that the language in Ex. DRA-46 was the complete rule.

Account 921 expenses are escalated, while Account 923 expenses are not. Portions o Account 921 expenses can also be capitalized (as part of capitalized A&G), thereby earning a return on rate base over (roughly) 30 years. Shifting Account 923 dollars to Account 921 may also overstate historical costs if those costs are used for forcasting future costs.

DRA, therefore, recommends that the Commission order an audit, to be paid for by SCE shareholders, to determine the exact impact of SCE's misuse of FERC accounts in a manner contrary to accepted accounting practices.

7.1. Application Services

SCE's Application Services Division supports SCE by solving business problems with information technology solutions. This Division delivers, tests and maintains systems for all business units within the company. SCE requests $112.9 million for Test Year 2012 forecast expenses for Application Services. DRA recommends $71.6 million for Application Services.

In 2005, Application Services recorded expense was $56.813 million; in 2006, the recorded expense was $58,903 million; in 2007, the recorded expense was $67,232 million. Recorded expense went down in 2008 to $64,881 million and in 2009 scaled more than $10 million over the three previous years to $82,747 million. SCE's request of $112.9 for Test Year 2012 Application Services expense is $30.1 million more than base year 2009 recorded expense and 58% greater than SCE's three year average of expenses in Application Services. If 2009 recorded expense were removed as an anomaly in the recorded historical expenses, SCE's 2012 request would be almost 100% more than all recorded costs back to 2005.

Historical fluctuations in labor and non-labor expenses for Application Services do not explain SCE's request and neither does the testimony on what Application Services contemplates in the GRC period. SCE's testimony is replete with details of what support Application Services already provides to SCE's business units but the only incremental cost is associated with the releases of the Enterprise Resource Planning (ERP) project[1094]. The 2009 increase was due to this ERP release. However, the ERP was fully implemented and completed[1095].

While Application Services also boasts of making SCE's various departments very efficient, there is not a single testimony in this GRC to support the fact that costs decreased in

---

[1094] Ex. SCE-06, p.27.

[1095] 1 RT 839:12 – 840:27, Yazdi/ SCE.

any SCE unit because of the efficiencies provided by Application Services in automating manual labor or increasing individual capabilities. Indeed, the testimony concedes that the support Application Services provides these units "are all traditional IT type responsibilities."[1096]

DRA derived its recommendation by averaging the last three recorded years, including the 2009 base year which in fact seemed like an outlier given the impact of ERP. SCE argues for an upward trend using adders, but the historical data is not indicative of a trend. In light of the fact that it is still unclear what hidden impact SCE's combination of FERC 920 and 923 accounts have on the expenses in IT&BI, the Commission should adopt DRA's recommendation.

7.2. Technology and Risk Management

SCE requests $34.51 million in Test Year 2012 expenses but DRA recommends $14 million. Technology and Risk Management (TRM) provides the architecture, engineering and cyber security services to protect the integrity of SCE's information technology systems and data. In this respect, TRM covers activities for which SCE is not supposed to seek recovery in rates from this Commission, but SCE included these items in its testimony anyway.

> Q. Rather than go through all the drivers [for the TRM forecast], let me just ask you about two of them, two aspects, and you tell me whether they are also drivers. …
>
> The NERC CIP?
>
> A. That is a big driver.
>
> Q. Can you explain why that is a big driver?
>
> A. NERC CIP is regulatory mandate that was issued by FERC in responses to the 2003 blackout that caused outages in northeast United States and Canada, impacted 40 million people and cost billions of dollars in just a matter of four days.
>
> So NERC standard was developed in response to that to have mandatory cyber securities and physical security standards enforceable through fines to be administered by NERC.
> And we became compliant with Version 1 in 2009. It required lots of resources to build the technical and procedural controls to protect the bulk power system critical assets.

[1096] Ex. SCE-05, Vol. 2, p.7.

> But ever since 2009 …As we predict in our filings, Version 5 is going to have a dramatic expansion of requirements.[1097]

Clearly, FERC authorized activities go into FERC authorized rates. The CPUC did not issue the mandate that created the NERC standard. SCE cannot logically claim that it was supposed to put these costs in this GRC rates.

> Q. What percentage of your projected test year estimates would you say is driven by the NERC CIP requirements?
>
> A. I haven't calculated. But you can see –
>
> Q. Can you give me just an estimate to the best of your ability right now?
>
> A. NERC CIP is a big driver. I will say may be 30 percent. This is just a guesstimate. I haven't looked at it in percentages here.
>
> Q. Do you have a driver that exceeds 30 percent by itself, just estimated?
>
> A. NERC is a big driver. A second driver is security, cyber security, the overall cyber security.
>
> Cyber security threats are increasing at an exceptional rate.[1098]

SCE's witness went on to estimate that cyber security would be another 30 percent of the driver of the forecast for TRM[1099]. Again, cyber security is a Homeland Security mandate subject to FERC tariffs, the cost of which should not be recovered in GRC rates. The Commission should also consider the fact that SCE misapplied FERC 920 and 923 accounts in presenting TRM expenses. Therefore, DRA's recommendation is reasonable and should be adopted.

7.3. Information Technology Expenses – Infrastructure Operations

SCE forecasts $23.90 million for Test Year 2012 Infrastructure Operations Management expenses. DRA recommends $18.91 million. According to SCE "Infrastructure Operations

---

[1097] 15 RT 2232:23 – 2233:26, Tessema/ SCE

[1098] 15 RT 2234:14 – 2235: 3, Tessema/ SCE.

[1099] RT. 2236:7-11 Tessema/SCE

Division of SCE's IT business unit is to provide reliable, responsive, and cost-effective operational IT products and services" for SCE employees.[1100] Infrastructure Operations Management spending history does not support SCE's requested 25% increase in costs for the Test Year.

SCE used the 2009 recorded year to derive its forecast, but DRA is concerned that SCE began merging FERC 920 and 923 accounts in 2009. Therefore, The Commission should reject SCE's methodology. The labor and non-labor expenses for this division are not indicative of an upward trend. Historically, the spending pattern has been relatively flat. DRA expects little change in the pattern for the future. Labor adjustments are covered by labor agreements and are factored into the attrition review and inflation adjustments. A trend requires a minimum of three years in one direction. Therefore, DRA used a three-year average, including 2009 data to derive its recommendation. The Commission should adopt DRA's recommendation.

7.4. Information Technology Expense -Business Operations Management

SCE forecasts $23.29 million for Test Year 2012 Business Operations Management A&G. As in all the other IT&BI categories, SCE adopted an upward trend to make its recommendation but the historical data does not show a trend for the three years between 2007 and 2009. DRA recommends $19.68 million for Business Operations Management using a three-year average of historical data. The difference in SCE's request and DRA's recommendation is $3.61 million.

Although SCE used a three year average method to estimate the labor costs in Business Operations Management, SCE resorted to an upward trend of the non-labor costs to estimate the test year non-labor forecast. The difference between using the same method for both labor and non-labor and using an average for labor but an upward trend for non-labor is $3.61 million. This amounts to a manipulation of the figures. DRA used a three year average for both the labor and non-labor costs. DRA's recommendation should be adopted.

[1100] Ex. SCE-05, Vol 2, p.52.

7.5. Information Technology –Capital Expenditures

SCE requests IT&BI capital expenditures of $225.85 million in 2010, $160.52 million in 2011, and $300.14 million in 2012.[1101] To derive DRA's forecast for 2010 through 2012 IT capital expenditures, DRA relies on SCE's historical level of spending.

SCE's recorded 2010 level of IT&BI capital expenditures was $217.21 million. Based on the six years of data from 2005 through 2010, one can observe that: (1) expenditures can vary from year-to-year; and (2) the expenditure level from 2005 is low compared to the other five years. As a starting point in developing its forecast, DRA calculates a 5-year average of capital expenditures from 2006-2010, which is equal to approximately $261.63 million, adjusted for inflation.

For 2010, DRA recommends that the Commission adopt the recorded capital expenditures of $217.21 million. At this time, DRA does not take issue with SCE's forecast of $160.52 million for 2011. Under normal circumstances, DRA would therefore be recommending a forecast of $160.52 million for 2011 and $261.63 million for 2012.

However, due to the bonus depreciation impacts from the Tax Relief Act of 2010, it would be advantageous for SCE to accelerate some of its capital expenditures from 2012 into 2011. DRA believes that taking a 2-year average of the 2011 and 2012 forecasts is a reasonable approach. Therefore, DRA recommends that the Commission adopt an average of DRA's forecasted IT capital expenditures for 2011 and 2012, which equals $211.08 million[1102] for each of those two years.

7.6. Information Technology – MRTU

DRA recommends that the Commission reject SCE's requests for all expenses related to the Market Redesign and Technology Upgrade (MRTU) from 2010 going forward. The Commission is currently considering the reasonableness of these costs in other proceedings, and until those proceedings are resolved there is no valid historical data for estimating a Test Year 2012 forecast in this GRC, whether by trending or averaging. In fact, SCE filed Advice Letter 2091-E requesting authorization to establish the MRTU Memorandum Account (MRTUMA) to record incremental costs associated with MRTU implementation. The Commission granted

---

[1101] Ex. DRA-16, p. 3, citing SCE's response to data request DRA-Verbal-019, Question 3 – updated 11-30-2010.

[1102] 0.5 * ($160.52 million + $261.63 million) = $211.08 million

SCE's request in Resolution 4087-E and also agreed with SCE that the incremental costs recorded in the MRTUMA be reviewed and collected through the Energy Resource Recovery Account (ERRA). SCE was to submit periodic estimates it planned to record in the MRTUMA to the Energy Division.

SCE has since filed its ERRA proceedings seeking recovery of MRTU incremental costs for 2008 and 2009 expenditures in April 2010 ERRA Reasonableness review. However, with only two years of data and mostly conjecture about the future of MRTU, SCE projects a 33% increase in MRTU capital and non-capital expense. The drivers for this projected cost are include NERC, CIP and convergence bidding costs.

On June 23, 2011, the Administrative Law Judges (ALJ) in the ERRA proceedings issued a ruling on a DRA motion to consolidate Commission consideration of all three utilities' MRTU implementation costs into a single proceeding.

> Although DRA makes a valid point regarding the similarity of issues, MRTU related expenses and capital is already in advance stages of each proceeding....
>
> For the 2010 record period ERRA proceedings … (as well as the recently filed SDG&E 2010 ERRA Capital [A.11.06-003] not included in DRA's motion), [DRA's] motion is granted. As these proceedings are in their early stages, there is an opportunity to consider MRTU issues as a whole without disruption to the overall ERRA proceedings."[1103]

In D.09-12-021, the Commission stated that the scope of its review of PG&E's MRTU cost is not necessarily a traditional reasonableness review but rather costs to be verified and that are incremental. This description of scope of reasonableness reviews in ERRA is equally applicable to the scope of reasonableness reviews in GRCs.

It is important to note that the MRTUMA remains operational. Therefore, SCE should continue to record and recover its incremental MRTU costs for this GRC.

7.7. Information Technology Capital – Capitalized Software

DRA has no comment on this subject at this time.

7.8. Other Capitalized Software

DRA has no comment on this subject at this time.

[1103] A.10-04-002, Ruling, pp. 5- 6.

8. Human Resources, Benefits and Other Compensation

8.1. Human Resources Department Expenses

DRA recommends only a $376,000 reduction from SCE's request of $28,384,000 for Human Resources Expenses. DRA derived its recommendation by reducing the number of new positions that SCE seeks to add in this GRC from seven to three positions. Nevertheless, DRA's recommendation amounts to simply rounding up SCE's request to the nearest million[1104] or less than 2 % of the total request.

SCE's Human Resources expenses have stayed largely the same over the last four recorded years. While Human Resources labor expense was increasing for 2007 to 2009, non-labor expenses were decreasing for the same period. The increases in labor expenses were about the same as the decreases in non-labor expenses, thus causing total Human Resources expense to stay the same. SCE's testimony explained that the increases in labor expenses were largely due to SCE's conversion of several contingent and contract worker positions to permanent position.

During the hearings, it became clear that the labor expenses increased by a corresponding number to the decreases in non-labor expenses because the contingent and contract worker expenses were recorded as non-labor expenses in FERC 921 accounts rather than FERC 923 accounts as required by the rules.[1105] Converting the contingent and contract worker positions to permanent positions likely resulted in a direct transfer of non-labor expenses to labor expenses[1106]. However, it is not clear from the record that this is exactly what transpired because SCE's data on contingent and contract workers has been buried in non-labor expenses where they cannot be examined separately.

DRA addresses SCE's elimination of FERC 923 account and the misuse of FERC 921 account in the section on Information Technology and Business Integration (IT&BI) expenses where SCE's witnesses testified extensively on this practice during the hearings. In any case, given this change in accounting practice SCE can hardly claim that DRA's recommendation for Human Resources Expense is unreasonable.

[1104] $28,384,000 - $376,000 = $28,008

[1105] 23 RT 3838:7 – 28; 3858 - 3859: Miller/ SCE.

[1106] 23 RT 3841:1 – 10, Miller/ SCE.

8.1.1. Executive Officers Compensation

Executive officers' cash compensation includes base salary, annual incentives, and associated expenses. SCE requests $19.549 million for Test Year 2012 executive officers compensation. This amount includes short term incentives which are referred to in the testimony as annual incentives. Consistent with DRA's recommendation for short-term incentives of other officers, DRA recommends that ratepayers only fund 40% of the short-term incentives in the executive officers compensation as well. D.09-03-025 supports DRA's proposed reduction of this incentive.

> We find including 50% of these [executive short-term] incentives reasonable. SCE estmates executive short-term incentives at $9.171 million out of a total of $24.588 in executive officer costs. Applying the 50% adjustment to this amount results in a downward adjustment of $4.586 million, yielding a total of $20.002 million in executive officer costs inclusive of short-term incentives as authorized herein. As noted above, reducing the amount of incentive for which ratepayers bear the cost is reasonable in light of current economic circumstances provided the total compensation levels are sufficient to attract and retain employees. [1107]

Since D.09-03-025 was issued, economic circumstances have worsened and even gotten precarious[1108], and SCE's compensation levels have not been affected by the recession[1109]. Given these facts, it is clear that the D.09-03-025 reduction of SCE's executive short term incentives did not affect SCE's ability to attract and retain employees.

DRA accepted SCE's use of last recorded year's data for estimating the Test Year 2012 EIC. This compromise was generous because SCE's recorded executive officers labor costs have trended downwards since 2007. In 2007 the labor costs which correspond to the base salary and annual incentives was $20.004 million and in 2009 $15,516 million.[1110] DRA then derived its recommendation for executive short-term incentives by first determining that figure from the total labor costs.

[1107] D.09-03-025, mimeo, p. 135.

[1108] http://www.reuters.com/article/2011/08/06/us-usa-debt-downgrade-idUSTRE7746VF20110806, stating that United State's credit rating has been downgraded for the first time since 1941.

[1109] Ex. SCE-6, Vol. 1, Figure II – 11, p.41.

[1110] Ex. SCE-6, Vol. 1, p. 41.

> As SCE did not forecast EIC expense amount, DRA recommends using the same percentage (57.4%) of Executive Officer Incentive Compensation for executives that was recorded in 2009.[1111]

This approach is consistent with SCE's use of the last recorded year expense for Test Year 2012 forecast for Executive Incentive Compensation (EIC). The cost of the executive officers short-term incentives using this formula is $8.890 million. Consistent with D.09-03-025, DRA reduced this amount by half for a resulting amount of $4,480 million. At this point in the analysis, it is important to note that DRA has only taken exactly what SCE requested and reduced it by Commission directive pursuant to D.09-03-025.

A significant portion of the EIC is based on "core earnings" that benefit shareholders. DRA recommends a further adjustment for these core earnings by reducing SCE's request by a further 10% or $896, 000.

8.1.2. Executive Officers Non-Labor Expense

DRA has not recommended a reduction in executive officers non-labor expense. SCE's request for executive officers compensation includes total non-labor expenses for executives and assistants of $4.032 million that DRA has adopted for its recommendation. Like executive officers labor expense, non-labor expense also showed a downward trend. In 2008, non-labor expense was $5.041 million and in 2009, $4.031 million. In light of this fact, DRA's further reduction of executive officers short-term incentives by 10% over the reduction found reasonable in D.09-03-024 is reasonable.

8.2. Human Resources Capitalized Software

Under Human Resources Capitalized Software, SCE seeks $3.9 million for a project it refers to as the Worker Provisioning Process Enhancement Project. DRA recommends that the Commission authorize $1.755 million for the reasons stated in this Section.

SCE describes this project as a "new project that will provide an on-line and automated system which will be used by the managers for the provisioning process".[1112] The project would improve the capability of managers in the hiring process and streamline the process itself. In

---

[1111] Ex. DRA-13, p. 7.

[1112] Ex. SCE – 6, Vol. 1, p. 47

addition, "the project will improve the process for off-boarding of retiring/terminating employees."[1113]

SCE does not explain why it chooses to add this project in a recessionary period to burden ratepayer purses, when employment and other economic activity are at their lowest ebb in decades and unemployment is at or near double digits. There is no cost benefit analysis for installing this program at this time or an explanation why something so basic as a process that "provides employees and contingent workers with SCE assets such as facility (badge) access, workspace, computers, software, other approved devices (e.g. cell phones), and basic access to SCE's information system" was not necessarily implemented until now. It took new hires six days on average after their official start date to receive necessary Information Technology (IT) equipment without the provisioning process[1114]. However, this six day delay says nothing about the efficiency the provisioning enhancement project adds to SCE managers' capability because SCE does not state the number of new hires and frequency of hiring. Instead of the necessary hard data for evaluating the cost effectiveness of the provisioning project, SCE lists the kinds of work its managers have to do without the provisioning project.[1115]

SCE scheduled the implementation of the Worker Provisioning Enhancement Project for completion in 2010 and budgeted $3.9 million for it as the request in the GRC. In March 2011, SCE provided DRA with a spreadsheet containing the 2010 recorded capital expenditures for the Human Resources software project versus the 2010 forecast (shown above).[1116] While SCE forecasted $3.086 million for 2010, only $1.755 million was spent in 2010 for the Human Resources capital project. DRA recommends that this 2010 recorded expenditure of $1.755 million be adopted instead of the $3.086 million.

8.3. Results Sharing

SCE uses the term Results Sharing interchangeably to refer to a sub-set of the company's Incentive programs as well as the company-wide Short-Term Incentives which comprises of Management Incentive Program (MIP), Executive Incentive Compensation (EIC) and

---

[1113] Ex. SCE – 6, Vol. 1, p. 47

[1114] Ex. SCE – 6, Vol. 1, p.

[1115] Ex. SCE. 6, Vol. 1, pp.48 – 49..

[1116] Ex. DRA-13, p. 31 citing E-mail from Russell Worden of SCE to Clayton Tang of DRA, March 15 2011, "2010 recorded cap ex to 2010 forecast."

interestingly enough, Results Sharing (RS). This Section discusses the smaller RS included in Short-Term Incentives. Section 8.5.2 will discuss the company-wide program that includes MIP, EIC and RS, under Short-Term Incentives. The recommendation in both sections is the same. DRA recommends that the Commission authorize only 40% of the forecasted Short-Term incentives for ratepayer funding. The reasons why the remaining 60% should be rejected and the monetary breakdown of these costs are discussed in Section 8.5.2.

Result Sharing provides pay based on evaluations of results in customer service, safety, cost control, and efficiency. The overall program highlights what employees can do to contribute to the success of the Company and provides a financial stake for employees to achieve Company and business unit/department goals[1117]. It would seem that an employee is given a "financial stake" in the Company vis-à-vis the Shareholders not the ratepayers. Indeed, a closer look at the factors used to do the evaluation shows that only customer service and safety factors inure to the benefit of ratepayers; cost-control and efficiency factors go directly to the bottom line of the Shareholders.

The design of the Results Sharing program places primary focus on the achievement of Company and business/unit department goals as well as the Company's O&M budget. The pool of dollars allocated to each business unit/department is determined by a combination of the achievement of Company goal, O&M budget performance, and the budget authorized by the 2009 GRC. Fifty percent of the award is adjusted based on business unit/department goals while the remaining 50 percent is not adjusted based on those goals.

8.4. Spot Bonuses

Spot bonuses are part of SCE's recognition programs. They are cash awards to reward employees for exceptional performance and outstanding achievement. SCE requests $5.067 million for Test Year 2012 expenses; DRA recommends that the Commission not authorize ratepayer funding of SCE's Spot Bonuses.

In SCE's 2006 GRC, the Commission stated:

> ...elected not to authorize recover [sic] of spot bonus program costs based on its apparent concern that SCE had not made a sufficient

[1117] See Ex SCE-6, Vol. 2, pages 13-14.

> showing of how the program would not encourage proper behavior which might conflict with ratepayer interest.[1118]"

Apparently SCE attempted to make the relevant showing in its 2009 GRC, but the Commission again rejected spot bonus award in that decision.[1119] Sadly, SCE has returned in this GRC to make yet another request for spot bonuses. DRA maintains that SCE has still failed to make any showing that would reduce its spot bonus from a speculative subjective enterprise to the objective standard the Commission requires.

> In the Total Compensation Study for this GRC, Hewitt, DRA, and SCE discussed all elements of compensation to be included in the study. Ideally, spot bonuses would be included in the Total Compensation Study. DRA, SCE and Hewitt did consider including SCE's spott bonus awards in the current Total Compensation Study, but excluded these costs because this data is generally not available in surveys on a position-by-position basis, and wide variances exist in the marketplace.

SCE is also seeking ratepayer funding of SCE's Awards to Celebrate Excellence (ACE) program of non-cash awards. DRA recommends zero ratepayer funding of this program.[1120] In SCE's TY 2009 GRC, the Commission denied all costs related to ACE, noting SCE's failure to provide a "specific forecast" for the program or that "ratepayer interest is served by the amounts awarded under the program."[1121] DRA recommends the Commission deny ratepayer funding of ACE Awards in this GRC too.

As DRA noted in its testimony, the ACE program does not provide a clear, identifiable benefit to ratepayers, and is not necessary to operate the utility business.[1122] If SCE wishes to provide this benefit to its employees, it can do so at shareholders' expense.

In Rebuttal, SCE argues that "SCE's modest program provides benefits to our employees and correspondingly to our customers."[1123] The example SCE gives for this statement, however, demonstrates just how inappropriate SCE's proposal is.

[1118] Ex. SCE-6, Vol. 2, pp. 30-31 citing D.04-07-022, mimeo, p.212

[1119] Ex. SCE 6, Vol., 2, p. 31, citing D.09-03-025, pp.133 – 134.

[1120] Ex. DRA-15, p. 18; Ex. DRA-13, p. 30.

[1121] D.09-03-025, pp. 133-134.

[1122] Ex. DRA-15, p. 18.

[1123] Ex. SCE-21, p. 33, lines 22-23.

In Rebuttal, SCE says:

> For example, a number of employees spend long hours preparing the general rate case Notices of Intent and Applications and answering data requests which, as it has turned out, have reached record numbers in this case. Given the number of uncompensated hours worked by many employees, providing recognition at *Company expense* or a modest gift through the ACE program shows the contributing employees that their extra effort is appreciated.[1124]

In fact, SCE is *not* seeking to provide recognition at *Company* expense, but at the expense of its ratepayers. In this GRC, SCE is seeking *billions* of dollars from its ratepayers, many of whom are already having difficulty getting by. The increases SCE seeks in this case, if granted, will largely benefit SCE's shareholders, through increased returns on increased rate base, and SCE's employees, through wage and benefit increases far beyond what SCE's ratepayers are likely receiving.

Moreover, the fact that SCE chose to present its GRC in a way that was both confusing and ill supported and thereby necessitated a "substantial" number of data requests seeking clarification or substantiation is no reason to burden SCE ratepayers still further. DRA recommends that the Commission deny ratepayer funding of ACE awards in this GRC as well.

In Rebuttal, SCE argues that the amount DRA recommends be removed from SCE's 2009 recorded expenses for ACE Awards is wrong because a portion of that $7.015 million is not included in SCE's GRC historical expenses in the first place, and the adjustment in DRA's Pension and Benefit proposals duplicates DRA adjustments in other areas.[1125] In support of this, SCE relies on a data request response it provided to one of DRA's auditors, and part of that auditor's testimony.

DRA disagrees with SCE's characterization of both the data request responses and the report of DRA's auditor. The words speak for themselves.

DRA's Audit Report says:

> In order for DRA to remove the awards from both historic detail and forecasted detail, segregation by FERC Account is required as these awards are spread throughout SCE's business units. DRA

[1124] Ex. SCE-21, p. 33-34, emphasis added.

[1125] Ex. SCE-21, pp. 37-38.

> requested this information be provided, and received the following from SCE:
>
> "Per D.09-03-025, ACE awards were removed from SCE's authorized Test Year 2009 revenue requirement. For Test Year 2012, ACE awards are included in the 5 years of historical labor expense for each business unit. Each business unit prepares its own labor forecast by using unique forecast methodologies (*i.e.*. averaging, trending, last year recorded, budget based). *Since ACE awards are recorded in each business unit and each unit forecast is based on different forecast methodologies, the total request for ACE awards can not be easily determined.* "[1126]

The SCE data request response then listed the total dollar amount for ACE awards included in the historical period (2005-2009) which DRA included in its Pensions and Benefits exhibit.[1127]

DRA's Audit Report continues:

> As a follow-up response, SCE provided additional information identifying historic ACE Awards from 2005-2009 by FERC Account. DRA noted, this listing was all-inclusive containing ACE Awards recorded to FERC Accounts that are not part of the rate case. Thus, the recommended reduction merely serves as a guideline for DRA's analyst. DRA's analyst as noted in Exhibit DRA-15 determines any test year forecasting impact, or actual removals form historic data.[1128]

SCE did not include a forecast of costs with its Direct testimony or in response to DRA's initial data requests. DRA has not attempted to verify the data SCE did belatedly provide and cannot, at this late date, vouch for its accuracy. DRA, therefore, continues to recommend the removal of $7,014,740 from the base year expense.

8.5. Executive Compensation

8.5.1. Overall Compensation Levels

SCE maintains that its overall compensation levels are designed to attract and retain executives[1129] and thus, relies on a total compensation comparison with the salary, short-term incentives, and long-term incentives "comparable" industries to determine its executive

---

[1126] Ex. DRA-22, p. 25 citing SCE Response to DRA-SCE-AUDIT-LMW-14, Q.17b, emphasis added.

[1127] Id., and Ex. DRA-15, p. 17.

[1128] Ex. DRA-22, p. 25.

[1129] Ex. SCE-6, Vol. 1, p.42.

compensation[1130]. However, incentives alone cannot determine whether an executive would accept a job at SCE or leave SCE[1131] and it appears that SCE has always promoted its top executives from within the company rather than employ them from outside the industry[1132]. Therefore, the claim that SCE cannot attract talent and is losing the talent within the company is highly exaggerated.

> People make decisions to join organizations for variety of reasons. …[E]ven in the case of (a company that has) a negative image people might still make the decision to join the enterprise for other reasons.[1133]

A total compensation study cannot be relied on to yield results that are always reasonable. In 2007, SCE's executives' bonuses exceeded the executives' base salaries, but SCE's witness could not explain why that was the case, or what was going on in the comparable industry to have caused that anomaly[1134].

In recent years, SCE's total compensation study has labored to find companies that are truly comparable to SCE in both size and type of business[1135]. Even when similar companies are found, the executive compensation data of such companies may not be publicly available as in the case of the Los Angeles Department of Water and Power (LADWP)[1136]. From year to year the mix of companies that comprise a comparable industry to SCE change significantly, either because the companies have gone out of business[1137] or the criteria used for comparison in the particular GRC period eliminated them. Given this lack of stability in the "comparable industry" why should the Commission give such overriding weight to unstable companies' policies on executive compensation?

[1130] 23 RT., 3826:5-8, Miller/ SCE.

[1131] 23 RT 3835, Miller/ SCE.

[1132] 1 RT 719:4 -720:15

[1133] 23 RT 3835:13 – 20 (Witness Patricia Miller, Vice President, Human Resources; Ms. Miller joined SCE in 2009 from AIG. Ex. SCE-6, Vol. 2, p.A-7.)

[1134] 23 RT 3830 – 3831, Miller/ SCE.

[1135] 2715:20 – 2716:28, Miller/ SCE.

[1136] 17 RT 2667:13 – 18, Worden/ SCE. (It should be noted that LADWP is not comparable to SCE in size [$3 billion vs. $11 billion] but in type of business)

[1137] 17 RT 2700:14 – 22, Worden/ SCE.

The studies of total compensation study, which use data 3 years prior to the Test Year, have always failed to reflect the times. While the landscape of California electricity industry moved from restructuring to electricity crisis, from vertically integrated to divestiture of utility generation ownership and then returned back to procurement, the only change that SCE's self-described veteran of the study[1138], could point to as how total compensation studies have reflected the times, is that the job categories used in the total compensation studies have changed from year to year[1139].

> Q. Now what I'm trying to get at is how did the total compensation study change to reflect the particular changes in the electricity industry in California?
>
> A. My recollection is that a number of the jobs that were selected are different.[1140]

A total compensation study may have some use, but whatever that use may be, it is not as a benchmark for determining SCE's overall compensation levels, especially during a recession. SCE is authorized its revenue in rates, so SCE's revenue levels are not subject to market fluctuations or a function of the Herculean efforts of its executives in marketing and finance and other Wall Street factors, but on the objective assessment of what is needed to provide safe and reliable service. If in the course of a rate period SCE feels that ratepayer safety or the reliability of the service could be improved with an expense for which it was not authorized revenue, it may return to the Commission, for example, requesting a memorandum account to record such expenses as incremental costs and eventually collect those in rates[1141]. Contrast SCE's ability to receive incremental expenses with R and R Donnelley which is losing several Divisions of Book Sellers due to the recession, clearly they are not comparable industries on so many levels.[1142]

DRA is currently reassessing the utility of total compensation studies in GRCs and whether to continue to participate in them. If upon conclusion of this reassessment, DRA determines that a total compensation study has completely outlived its usefulness and cannot be

---

[1138] 17 RT 2698:13 – 2699:28, Worden/SCE.

[1139] 17 RT 2701:9 – 28.

[1140] 17 RT 2701: 23 – 28, Worden/ SCE.

[1141] Resolution E-4087

[1142] 17 RT 2674: 13 - 28

salvaged by re-design, the Commission should allow DRA to exercise its independence under the statute[1143] and seek an alternative method to a total compensation study. SCE may continue with the study, if it wishes, but the study should not be given any weight in a GRC as a legitimate benchmark.

> Q. Mr. Worden, given the changes which have taken place in the electricity industry in California and the fact that the compensation study has been - - the process has been fairly the same over the years, would it surprise you to know that DRA's responses to the study in this testimony was an attempt to make an outdated concept fit current needs?
>
> A. No.[1144]

8.5.2. Short Term Incentives

Short-term incentives are a set of programs that SCE claims are designed to attract, retain and reward employees for performance. SCE requests $148.640 million to fund its Test Year 2012 Short-term Incentive program. This amount was determined in two steps. First, SCE established an expense ratio by dividing the 2009 Result Sharing[1145] cost by the 2009 recorded labor expense[1146]. The expense ratio is stated as a percentage. In the next step, SCE applied the expense ratio to the projected non-capital labor forecast for 2010 – 2012[1147].

DRA recommends that ratepayers fund only 40% of SCE's requested $148,460,000. This amount will provide each eligible SCE employee a yearly prospective bonus of 5% of the base annual salary. Incentives are not like other expenses in that their expenditure is completely under the discretionary control of the Company and subject to change regardless of the amount authorized. A strict incentive target might make the amount awarded in any given year substantially less than the authorized amount. According to a new article, PG&E recently canceled its 2010 cash bonuses.

[1143] Public Utils. Code §309.9

[1144] 17 RT 2717: 25 – 2718:6, Worden/ SCE.

[1145] RS here refes to the total 2009 short-term incentives.

[1146] Ex. SCE – 06, p.17.

[1147] Ex. SCE – 06, p.17

> PG&E's proxy statement says the decision came in response to the 'challenges' besetting PG&E Corp and its utility, Pacific Gas and Electric Co. last year.[1148]

PG&E Corp. apparently made the decision to cancel its cash incentives without fear of losing talent within the company or failing to attract talent. Indeed reducing incentive awards, may be a motivational incentive, as a criticism of past performance.

SCE's method of calculating its incentive is arbitrary. It is not based on the performance SCE would achieve in the period that this GRC covers, because that cannot be known at this time. The average recorded incentive payout for the four years from 2005 through 2008 was $104.3 million[1149]. This amount increased to $124.7 million in 2009. SCE forecasted $138,979 million for 2010 and $148.5 million in 2012[1150].

Consistent with the rationale in D.09-03-025 that incentive programs that essentially benefit shareholders should not be sponsored entirely by ratepayers, DRA believes it is time for the Commission to end ratepayer sponsorship of SCE's discretionary Short-term Incentive program.

SCE determines employee incentives by establishing 24 company goals that the employees should strive for in a given year. If at least 18 of the goals were deemed met in a given year, the full corporate funding is granted. A second criterion is whether the company is under budget or over budget against the O&M budget. If under budget, the pool is increased, and, if over budget, the pool is decreased. From 2005 through 2009, SCE concluded that the company achieved the required number of goals for 100% target funding. As for O&M budget, this was used as a criterion for 2006 – 2009 and coporate funding only varied from 98% to 105%. Thus, qualified employees received from 98% to 105% of their target incentives from 2005 through 2009.

In regard to O&M budget, using this as a criterion to determine funding of incentives provides benefits for shareholders. Whenever company costs are held below the O&M target, shareholders, not ratepayers, reap the savings and benefits. Concerning the company goals, most of the company goals SCE stated in its testimony appear geared towards efficiency and cost

---

[1148] Ex. DRA-13, p. 6.

[1149] Ex. SCE – 6, p.13

[1150] Ex. SCE – 6, p.13

control factors that inure to the benefit of shareholders rather than ratepayers.[1151] Table 13-10 in DRA's Ex. 13, shows some of SCE's company wide goals. Among these (1) CPUC Disallowances, (2) Least Cost/Best Fit Power Procurement; and (3) RPS Compliance are not appropriate factors for granting incentives with ratepayers funds. By law, the Commission is required to refrain from after-the-fact reasonableness reviews which is primarily the basis for CPUC Disallowances.

> AB 57 Directs the Commission to review each utility's procurement plan in a manner that:
>
> Assures creation of a diversified procurement portfolio
>
> Assures just and reasonable electricity rates
>
> Provides certainty to the utility in order to enhance its financial stability and creditworthiness
>
> Eliminates the need, with certain exceptions, for after-the-fact reasonableness reviews of a utility's prospective electricity procurement performed consistent with an approved procurement plan.[1152]

Absent fraud and misrepresentation, it is difficult to contemplate an instance where the Commission may order a disallowance under AB 57. No such disallowance has occurred to DRA's knowledge since AB 57 became law, almost a decade ago. Therefore, this incentive amounts to a bonus payment for not committing fraud.

Similarly, Least-Cost/Best-Fit is a Commission directive that utilities must meet in their procurement and dispatch of resources. It is unclear why SCE salaried employees would engage in a transaction that is not either the "least-cost" alternative or the "best-fit" alternative among the available options. Arguably, it would be more difficult to engage in procurement that is neither least-cost nor best-fit than to do a procurement that is both least-cost and best-fit. How does SCE determine that a particular employee failed to meet the Least-cost/Best-fit performance target when other employees within the company meet the target? This standard is not verifiable.

[1151] Ex. DRA-13, p. 20, lines 23-25.

[1152] Public Utilities Code §454.5.

RPS compliance is the law[1153]. The RPS law requires utilities to procure at least one percent of their customers' retail needs from renewable resources every year until they reach 33%. Utilities are subject to penalties if they fail to comply and may be excused from compliance for reasonable justifications known as flexible compliance mechanism. Since RPS became law, no utility has been penalized for non-compliance and the record shows that SCE has executed enough contracts to meet its 33% RPS obligation, should all the executed contracts come on-line.[1154] The rest of the responsibility is with the developers and counter-parties to meet their contractual obligations and bring the resources online. Further, RPS statute provides that in the event of non-compliance, shareholders not ratepayers will be responsible for the penalties. Requiring ratepayers to fund SCE's performance bonuses based on RPS compliance will undermine the statutory requirement that shareholders bear responsibility for non-compliance. Any penalty imposed against SCE might be offset by the bonuses ratepayers have been funding over the past decade. This profligacy of the past decade alone should be sufficient to justfy DRA's recommendation that ratepayers fund only 40% of SCE's short-term incentive programs.

Only a subset of SCE employees are responsible for most of the other company goals. Therefore, SCE's use of a formula based on the expense ratio that is derived as a factor of total labor expense is excessive. Rooftop Solar execution, Power Procurement Excellence, Regulatory and Legislative Advocacy and Major Regulatory Proceedings are largely the responsibility of the PPBU. In any case, these company goals to go efficiency and cost control, which protect the shareholders bottom line.

In D.04-12-048, the Commission sought to establish a level playing field between utilities and Independent Power Producers (IPP) for procurement of electricity in a hybrid market. This means that ratepayer funding should not give utilities an undue advantage in procurement that is not also available to IPP's in the procurement field. In the Rooftop Solar project application for instance, the Commission carved out a part of the project for IPPs in a hotly contested proceeding. Ratepayer funding of incentives based on SCE employee's execution of the Rooftop Solar project violates this Commission policy for a level playing field. It should be noted that most power contracts have incentives built into them and damages for failure to perform.

[1153] Public Utilities Code §399.11

[1154] 21 RT 3451:22-3452:5 Ulrich/SCE.

Authorizing ratepayer funded incentives for SCE employees for Power Procurement excellence might be rewarding them for third party obligations.

SONGS operational excellence and steam generator replacement execution milestones and budget is an incentive that SCE should be required to obtain by application to the Commission before it is funded by California ratepayers. SCE, San Diego Gas & Electric (SDG&E) and an Arizona utility company own parts of SONGS. SCE should not be awarded ratepayer funded incentives until the Commission has had a chance to examine the role of the other owners in achieving the goals that SCE attributes to its ratepayers. Further, because SONGS is a nuclear generating facility, the Commission should pay closer attention to any incentive that has to do with the facility.

Therefore, DRA recommends that ratepayers fund no more than 40% of the Short-term Incentives. In making this recommendation, DRA took into account the most recent PG&E GRC for Test Year 2011 where the Commission approved a settlement removing over 40% of PG&E's employee short-term incentive[1155].

8.5.2.1. Executive Incentive Compensation

8.5.3. Stock Options and Other Long-Term Incentive Programs

Long-term incentive consists of non-qualified stock options, restricted stock units and performance shares SCE awards to executives and the management tier immediately below executives[1156]. The mix of options, restricted stock units, and performance shares may vary by employee rank and may change from year to year. SCE forecasts $19.8 million for long-term incentives related costs in Test Year 2012.

In 2009 the Commission rejected SCE's request to include Long-term incentives in rates for SCE. In D.09-03-025, the Commission stated:

> As DRA and TURN note, these incentives have not been included in rates in the past and are closely tied to stock performance of the parent company, Edison International, and, therefore, to non-utility activities. We continue the Commission's existing policy of excluding these amounts from revenue requirement. Furthermore, in light of the current economic situation and the dire financial circumstances many Californians find themselves in, it is reasonable to limit the level of executive compensation ratepayers are responsible for provided such reductions do not result in

[1155] Ex. DRA 13, citing Decision 11-05-018 for PG&E's Test Year 2011 General Rate Case.

[1156] Ex. SCE-06, Vol. 2, p. 20

> total compensation falling below the amount required for Edison to attract and retain employees.[1157]

SCE should petition the Commission for modification of D.09-03-025 before it seeks an award for Long-term incentives in a GRC. Nothing has changed since the Commission issued D.09-03-025 that would support reversing the Commission precedent. The fact that in 2009 SCE requested $23.3 million in Long-term incentives and now requests $19.9 million does not constitute a changed circumstance sufficient to support modification of the decision.

8.6. Pensions and Benefits

Pensions and benefits expenses (P&B) is defined as all employer-provided employee benefit plans and programs, recorded in Federal Energy Regulatory Commission (FERC), Form No. 1, Account No. 926. This includes pensions, post-retirement benefits other than pensions (PBOPs), health care, 401(k) plans, disability, group life insurance, and executive benefits.

SCE requests $563.60 million in pensions and benefits[1158] for the test year. SCE's request is based on the assumption that the Commission will adopt all the 1,500 "net new hires"[1159] which accounts for about $4 million in SCE's proposed pension costs and about $1 million in SCE's proposed PBOPs costs. SCE says its "...Reflection of 1,500 Net New Hires in Pension and PBOP Cost Projections is Reasonable."[1160] As discussed throughout this Brief, DRA considers SCE's projections of ratepayer funding for 1,500 additional net new hires to be overblown and wholly unreasonable.

For this and other reasons discussed below, DRA recommends ratepayer funding of no more than $304.25 million for TY 2012[1161] for pensions and benefits costs. The areas where DRA disagrees with SCE's specific forecasts are discussed below.

[1157] See D. 09-03-025, pp. 134-135.

[1158] Ex. SCE-06, Vol. 2, p. 34.

[1159] 20 RT 3156-3157, Henry/ SCE.

[1160] Ex. SCE-21, p. 67, lines 1-2.

[1161] DRA's forecast amounts amounts include benefits related to the Four Corners generation station. DRA is removing 25% of these costs in Rate Recovery to reflect the sale of Four Corners on October 1, 2012. The total impact to P&B will be approximately $117,000. DRA's recommendations relating to the Four Corners generation station are discussed in more detail in Section 4, above, and in Ex. DRA-9 at page 8.

8.6.1. Pensions

SCE seeks ratepayer funding in the amount of $168.40 million for pension costs for the test year. DRA recommends ratepayer funding of no more than $52.95 million.[1162]

SCE's forecast is based upon determinations made by the retirement plan actuary, Aon Consulting. Aon used the same actuarial cost method (Frozen Initial Liability) in its calculations that it has used for past SCE rate cases, but adopted a two-year asset smoothing method for minimum funding calculations as provided under the Pension Protection Act of 2006 (PPA). SCE's forecast is a three-year average of the Rate Recovery Allowance amounts calculated by Aon, assuming quarterly payments.[1163] SCE says that, in the current economy of lower interest rates and with its "credit balances" to be used up before 2012, its pension fund will require higher levels of funding than ever before to sustain viability. As noted above, SCE also projects an increase of 1,500 employees before the test year, an increase of nearly 10% over the Company's current population, which results in a projected pension rate recovery cost increase of $4.12 million.[1164]

SCE's request of $168.4 million is 81% higher than the 2009 actual pension expense of $92.6 million, 218% higher than the amount authorized in the last GRC, and 153% higher than the average pension expense from 2005 through 2009.

Actuarial reports, on which the pension estimates are based, use extremely conservative interest rate and valuation assumptions which help protect employees and shareholders, but do not take into account the interests of ratepayers. Ratepayers, however, are the ones who must shoulder the burden of this expense, which is unique in ratemaking because current ratepayers are funding *future* benefits.[1165]

To aid in its determination of the appropriate Test Year pension expense level, DRA attempted to gather the most recent information available about SCE's pension plan. To that end, DRA asked SCE for the pension plan actuarial report for plan year 2011, which would give

---

[1162] Ex. DRA-15, p. 2, Table 15-1.

[1163] Ex. SCE-6, Volume 2, p. 46.

[1164] Ex. SCE-6, Volume 2, workpapers Pt. 1, Chapter VII, p. 28.

[1165] Ex. DRA-15, p. 5.

the most current showing of the pension plan's funded status; SCE responded it would be available in the fourth quarter of 2011.[1166]

Because SCE used a two-year asset smoothing method which includes 2008, undeniably one of the worst financial years in recent history, along with 2009, DRA asked that the 2010 report be recalculated using only 2009 information. SCE refused saying it did not have the requested analysis and that preparation of such a report would be "burdensome."[1167]

DRA requested the 2010 report be recalculated using the plan's actual rate of return on assets for 2010. SCE refused.[1168]

DRA requested that the 2010 report be recalculated using the plan's actual end-of-year 12/31/10 fair market value. SCE told DRA to look at responses SCE had provided to "similar" questions from TURN,[1169] and SCE's 2010 Report.

As DRA noted in its testimony, in this computer age, using modern computer models, DRA's requests to make simple changes to consider more recent information are not burdensome. In fact, in pension discussions with Pacific Gas and Electric Company (PG&E) in 2009, PG&E's actuarial consultants did just this, multiple times, at DRA's request, often with less than a week's turnaround.[1170] PG&E's cooperation in rerunning the actuarial calculations allowed DRA to make reasonable recommendations, and enter into a settlement that was satisfactory to all parties.

SCE's pension trust fund earned a higher rate of return in the last two years (24.4% in 2009[1171] and 15.4% in 2010[1172]) than the 6.69% and 6.76% assumed in the actuarial report.[1173] The end-of-year plan assets were valued at $3.066187 billion[1174] which was much higher than

---

[1166] Ex. DRA -7, p. 5 citing Response to DRA-SCE-204-STA, Q/A 1.

[1167] Ex. DRA-7, p. 5 citing Response to DRA-SCE-263-STA, Q/A 1 and 2. See also Ex. SCE-21, Appendix, p. E-163.

[1168] Ex. DRA-7, p. 5, citing Response to DRA-SCE-081-STA, Q/A 5.

[1169] Ex. DRA-15, p. 5 citing Response to DRA-SCE-261-STA, Q/A 1 and 2. See also Ex. SCE-21, Appendix, p. E-117.

[1170] Ex. DRA-15, p. 6.

[1171] Ex. DRA-15, p. 7.

[1172] Id.

[1173] Ex. SCE-6, Volume 2, workpapers Pt. 1, Ch. VII, p. 35, notes for line B4 and D4.

[1174] Ex. DRA-15, p. 7.

the projected 1/1/2011 market value of $2.803801 billion.[1175] It thus seemed likely to DRA that running the actuarial calculations with the actual rate of return, actual plan asset valuation at year's end, and/or without the asset smoothing inclusion of 2008 could result in a lower required contribution.

In light of SCE's refusal to provide updated information, DRA considered SCE's forecast to be overstated. Therefore, DRA recommended in its testimony that the Commission authorize no more than the pension expense authorized in the 2009 GRC, which was $52.947 million.[1176]

In its Rebuttal, SCE characterizes DRA's proposal to keep ratepayer funding of the Pension costs at 2009 levels and to adopt a one-way balancing account as adjustments made "...in an apparent pique because SCE was unable to provide pension-related scenarios on demand."[1177] SCE is mistaken. DRA made its recommendations based on the information it could obtain in time to review. In the absence of updated actuarial information, DRA considered SCE's forecast unreliable. In the absence of clear and convincing evidence that an increase is justified, SCE's pension funding should be held at the level authorized in the prior GRC.[1178]

Nothing SCE provided in Rebuttal changes that assessment. SCE's argument that it was "Not Unresponsive" to DRA's requests for information is patently false. The responses to TURN's data requests did not answer DRA's questions. Nor is it possible to glean the answers from SCE's 2010 Report.[1179]

In its Rebuttal, SCE provided, for the first time, some tables prepared by its actuary which ostensibly show that "[d]espite favorable investment performance, the plan's funded status has deteriorated."[1180] This still does not answer DRA's request to "[p]lease provide updated minimum contribution amounts for the years 2012 through 2020 using the January 1, 2011 actual plan value of the pension trust, and *without using any asset smoothing methodology*."[1181]

[1175] Ex. SCE-6, Volume 2, workpapers Pt. 1, Ch. VII, p. 34, line D3.

[1176] D.06-05-016, page 142.

[1177] Ex. SCE-16, p. 17, lines 3-6.

[1178] Public Utilities Code §§ 451, 454.

[1179] Xx RT xx, Henry/ SCE.

[1180] Ex. SCE-21, p. 48.

[1181] Ex. SCE-21, Appendix, p. E-163, emphasis added.

SCE made the decision to use a smoothed asset in 2010 which includes 2008, a year in which SCE's plan experienced one of its worst losses ever. Now, SCE says, it is required by the PPA to continue to use the same method.[1182]

SCE's decision to include 2008 likely has a negative impact on its ratepayers by setting a higher minimum contribution level than might otherwise result if 2008 were excluded. SCE's ratepayers should not have to pay for SCE's poor-decision making, especially in light of SCE's complete failure to make any effort to mitigate the impact of this pension funding request on its ratepayers. Since, apparently, only SCE or its actuary can perform the calculation to determine minimum contribution levels without asset smoothing, DRA continues to recommend that the Commission authorize no more than the pension expense authorized in the 2009 GRC, which was $52.947 million.[1183]

DRA also continues to recommend the Commission adopt a one-way balancing account for SCE's Pension costs. In DRA's testimony, DRA suggested that SCE explore other options for its employees' retirement needs. Such options might include eliminating the pension program for new employees and switching those new employees entirely to a 401(k) plan, splitting pension expense between ratepayers and shareholders, and having employees fund a portion of their own pensions, as many state and other employees do.[1184]

SCE's response in its Rebuttal was to catalog all the things SCE says it cannot or will not do, but offers nothing constructive to lessen the impact of its request on its ratepayers. Not only has SCE made no effort to mitigate the effect of its pension proposals on the customers who would pay for them, SCE seems to have made no effort to find out what the effect might be.

At the time DRA prepared its testimony, California as a whole had a 12.3% unemployment rate[1185] with many areas within SCE territory experiencing even higher rates: the Bakersfield/Delano area, 17.0%; the Fresno area, 18.2%; the Hanford/Corcoran area, 18.0%; and the Visalia/Porterville area has an 18.1% unemployment rate.[1186] Nearly half of the households

---

[1182] Ex. SCE-21, p. 46.

[1183] Ex. DRA-15. [/ 7.

[1184] Ex. DRA-15, p. 9 citing "CalPERS Responds" http://www.calpersresponds.com/myths.php/myth-Government-workers-dont-contribute-to-their-pensions.

[1185] Ex. DRA-15, p. 8 citing http://www.bls.gov/feed/lau_latest.rss (updated Wednesday, April 06, 2011).

[1186] Ex. DRA-15, p. 8 citing http://data.bls.gov/cgi-bin/surveymost?la+06 (details for the areas listed).

in Kern and Tulare counties, and more than 73% of households in Imperial County, qualify for low-income rate assistance, according to an annual compliance filing regarding the annual estimates of CARE-eligible customers.[1187]

From these statistics, the Commission can infer that many of SCE's ratepayers are in a worse financial condition than is SCE's retirement plan, and many of SCE's ratepayers have likely experienced a decline in their own retirement savings during the recent economic downturn.

SCE's shareholders earned a rate of return of 9.2% in 2009[1188] despite the economy, and SCE's employees contribute nothing to their pension plan.[1189] The Commission should not increase benefits to SCE's shareholders and employees at ratepayer expense when many of those same ratepayers are struggling.

In light of the particular circumstances in this case, DRA recommends a one-way balancing account for SCE's pension costs. SCE seeks a two-way balancing account, which DRA opposes. A two-way balancing account for pensions renders the GRC forecast meaningless and it provides no "checks and balances" for the annual pension contribution. A one-way pension balancing account protects ratepayers in any year where the actual pension contribution is less than the authorized amount.

One of SCE's arguments in favor of the two-way balancing account is that it "…gives SCE the ability to make any necessary Retirement Plan design changes at any time."[1190] DRA believes that Retirement Plan changes that increase benefits should be concurrent with a GRC so they can be more closely scrutinized than the review process of Advice Letter filings allows. DRA proposes that the Commission not authorize SCE to make any pension plan changes that increase contributions during the time period covered by this GRC, or that ratepayers not be required to fund any benefit increases during this time.

In the event that the Commission adopts a two-way pension expense balancing-account, DRA proposes a cost sharing mechanism whenever actual pension contributions exceed the

---

[1187] A.08-05-026, Attachment A

[1188] Ex. SCE-10, Volume 1, Table II-1, line 26. The 2009 rate of return is higher than the authorized rate of return, which was 8.75%.

[1189] Ex. SCE-6, Volume 2, workpapers Pt. 1, Ch. VII, p. 36.

[1190] Ex. SCE-6, Volume 2, p. 48.

authorized contribution. DRA acknowledges that pension-contribution expenses are affected by such variables as pension law and interest rates, some of which are beyond the Company's control. There should, however, be some incentive to SCE to control costs, rather than an unlimited pass-through to the ratepayer of 100% of such expenses with absolutely no control or accountability. A cost-sharing mechanism, for expenses above the annual authorized amounts, accomplishes this purpose. Should a given year's contribution exceed that year's authorized amount, 75% of the excess will be borne by ratepayers via the balancing-account mechanism, and the remaining 25% borne by shareholders.[1191]

8.6.2. PBOPs

SCE seeks ratepayer funding in the amount of $53.63 million for PBOPs costs for the test year. DRA recommends ratepayer funding of no more than $50.99 million.[1192] The difference between the two forecasts is due to DRA's removal of funding for SCE's projected increase in employees.

As with the Pension forecasts, DRA requested an update to the PBOP actuarial reports using the actual trust fund value at 2010 year end. SCE refused to provide one.[1193] DRA considers a lower PBOP test year expense is likely appropriate, for the same reasons described in connection with the Pension forecasts. In its testimony, DRA accepted $50.99 million as the TY 2012 PBOPs under the mistaken impression that SCE's ratepayers would be protected by a one-way balancing account.[1194]

DRA recommends the Commission adopt a one-way balancing account for PBOPs so that, in the future, SCE's ratepayers are protected from SCE's over-estimates.

8.6.3. Other Benefits

8.6.3.1. 401 (k) Savings Plan

SCE's forecast of 401(k) Savings Plan expense for the test year is $88.27 million.[1195] DRA recommends ratepayer funding of no more than $31.20 million. SCE says its forecast is

---

[1191] Ex. DRA-15, p. 9.

[1192] Ex. DRA-15, p. 2, Table 15-1.

[1193] Ex. DRA-15, p. 14 citing SCE Response to DRA-SCE-263-STA, Q/A 3.

[1194] Ex. SCE-15, p. 14.

[1195] Ex. SCE-06, Volume 2, Ch. VII, p. 48.

based on historic program cost, and the increase is driven by projected increases in the number of employees and their base salaries.

SCE's 401(k) Savings Plan allows employees to defer current income, often on a pre-tax basis, to help support their retirement.[1196] SCE matches each employee's contribution, dollar for dollar, up to six percent of their base pay.[1197] The plan offers more than 40 investment options from which employees select to invest their own deferrals.[1198]

Paragraph (k) was added to Section 401 of the Internal Revenue Code in 1978 in an attempt to resolve a conflict involving the cash-deferred profit sharing plans that some of the major banks were offering employees at the time.[1199] By the mid-1980s, 401(k) savings plans had been widely adopted as an "alternative" to the more costly defined-benefit pension plan that smaller companies could not afford to offer.

SCE's ratepayers are being asked to fund two retirement plans for SCE employees, both the pension plan and the 401(k) savings plan. This is excessive, especially at a time when many ratepayers are faced with unemployment and an insecure financial future for themselves. According to annual surveys done by the Profit Sharing and 401(k) Council of America (PSCA), a national, non-profit association specializing in profit sharing and 401(k) plan design, administration, investment, compliance and communication, the average company contribution to 401(k) plans in 2009 was 2.1%.[1200] This is down from 2.9% in 2008[1201] and 3.2% in 2007.[1202] The annual PSCA survey is widely quoted as a benchmarking tool for both employers and employees.

DRA used the average of those three years' average contribution rates, 2.73%, to determine an acceptable ratepayer funding level, which would be comparable to what other

---

[1196] Ex. SCE-6, Volume 2, Ch. VII, p. 48.

[1197] Ex. SCE-6, Volume 2, Ch. VII, p. 49.

[1198] Ex. SCE-6, Volume 2, Ch. VII, p. 49.

[1199] Ex. DRA-15, p. 11 citing "The Handbook of Employee Benefits," by Burton T. Beam Jr. and John J. McFadden, p. 685-686.

[1200] Ex. DRA-15, p. 11 citing"53rd Annual Survey of Profit Sharing and 401(k) Plans" published by the Profit Sharing and 401(k) Council of America.

[1201] Ex. DRA-15, p. 11 citing "52nd Annual Survey of Profit Sharing and 401(k) Plans" published by the Profit Sharing and 401(k) Council of America.

[1202] Ex. DRA-15, p. 11 citing, "51st Annual Survey of Profit Sharing and 401(k) Plans" published by the Profit Sharing and 401(k) Council of America.

companies throughout the U.S. are matching for their own employees. DRA applied the resulting 2.73% contribution rate to SCE's FERC Form 1 labor amount for 2009[1203] to determine the base year program cost, which was then escalated to the test year expense.

In its Rebuttal, SCE refers to its 401(k) plan as an "integral component of its Total Compensation which has been found to be reasonable."[1204] From DRA's perspective, as discussed in more detail above, the Total Compensation Study is a dated concept of limited usefulness in the current environment. In any event, though, as the Commission found in SCE's last GRC, "[t]he total compensation study does not address the issue of whether SCE's compensation is "reasonable."[1205] Nor does the Total Compensation Study address the issue of who should bear the costs of the compensation – ratepayers or shareholders.[1206]

DRA continues to recommend no more than $31.20 million in ratepayer funding for SCE's 401(k) plan.

8.6.3.2. Medical Programs

SCE seeks ratepayer funding in the amount of $167.78 million for Medical Program costs for the test year. DRA recommends ratepayer funding of no more than $122.60 million.[1207]

SCE's forecast of medical programs expense for the test year is $167.77 million.[1208] SCE's estimate was forecasted by escalating the 2009 expense by a 10% escalation rate each year.[1209]

DRA recommends using Global Insight's medical escalation rates of 4.9% in 2010 and 4.2% in 2011 and 2012, discussed in sub-section 1 below. DRA also recommends removing $10 million from the 2009 base year expense, before escalation, to reflect an over-collection of health care costs in 2009 and 2010, discussed in sub-section 2 below. The total of these adjustments, along with a different labor estimate, results in a DRA test year estimate of $122.60 million.

[1203] $1.039 billion, from Ex. SCE-06, Volume 2, workpapers Pt. 1, Ch. VII, p. 84.

[1204] Ex. SCE-21, p. 58.

[1205] D.09-03-025, mimeo, p. 127.

[1206] Id.

[1207] Ex. DRA-15, p. 2, Table 15-1.

[1208] Ex. SCE-6, Volume 2, p. 50.

[1209] Ex. SCE-6, Volume 2, workpapers Pt. 1, Ch. VII, p. 162.

In determining the reasonableness of SCE's escalation rate, DRA consulted several well-regarded sources of health care cost statistics. According to the Global Insight "Cost Planner," which DRA and SCE are both using to support other escalation rates in this GRC, employer-sponsored health care costs are expected to increase 4.9% in 2010, 4.2% in 2011, and 4.2% in 2012.[1210] DRA recommends that these medical escalation rates be used to develop the test year forecast. Towers Watson's 2010 Health Care Cost Survey found that the average health care cost increase for employers was 6.00% in 2009 and 7.00% in 2010[1211] and that the annual cost increases for health care benefits have been stable between 6% and 7% over the last six years.[1212] The Kaiser Family Foundation's annual Employer Health Benefits surveys found that employer-sponsored premiums for family coverage increased 5% from 2008 to 2009[1213] and 3% in 2010.[1214] All of these sources are lower than SCE's estimate.

SCE uses Global Insight as the source for all other escalation rates in this GRC. In fact, the Global Insight medical care escalation rate is the only escalation rate that SCE removed.[1215] Because Global Insight is the authority that SCE is using for other escalation rates, and because Global Insight's estimates are in the range supported by employer health care cost surveys performed by known experts on the subject, DRA believes that the Global Insight medical care escalation rates are reasonable and should be used in this case.

The Commission set up the Medical Program Balancing Account (MPBA) in the 2009 GRC to record the difference between the authorized amounts and the actual costs of SCE's medical, dental, and vision expenses.[1216] SCE seeks to discontinue the MPBA effective on the date of the decision in this GRC.[1217] In 2009, SCE over-collected $2.29 million in the ten months of balancing account treatment; in 2010, SCE over-collected $10.46 million[1218] or

---

[1210] Ex. DRA-15, p. 12 citing Global Insight, "Cost Planner," Fourth Quarter 2010, p. 149.

[1211] Ex. DRA-15, p. 12 citing Towers Watson 2010 Health Care Cost Survey, p. 4.

[1212] Ex. DRA-15, p. 12 citing Towers Watson 2010 Health Care Cost Survey, p. 5.

[1213] Ex. DRA-15, p. 12 citing http://ehbs.kff.org/pdf/2009/7937.pdf.

[1214] Ex. DRA-15, p. 12 citing http://ehbs.kff.org/pdf/2010/8086.pdf.

[1215] Ex. DRA-4, p. 15.

[1216] D.09-03-025, p. 143.

[1217] Ex. SCE-10, Vol. 1, page 41.

[1218] Ex. DRA-15, p. 13 citing Response to DRA-SCE-203-STA, Q/A 1, attachment for 2010, line 21 plus line 53.

roughly 8.3% of the total authorized amount for the year. If DRA's proposed escalation rates are adopted, DRA would accept the MPBA being eliminated; if SCE's excessive escalation rates and labor increases are adopted, then DRA recommends that the MPBA be required.

The actual $12.75 million over-collected in the MPBA will be returned to ratepayers via advice letter filing[1219] but such a large amount may indicate that the base year expense is inflated. Although the MPBA includes dental and vision expenses as well as medical expenses, the authorized amounts total only 15% of the total booked to the MPBA; the remaining 85% is medical expense. DRA recommends that $10 million be removed from the medical base year expense.

8.6.3.3. Disability Program

SCE seeks ratepayer funding in the amount of $31.77 million for Disability Program costs for the test year. DRA recommends ratepayer funding of no more than $23.40 million.[1220]

SCE's disability programs provide income protection when an employee is too sick or injured to work. The programs include the Comprehensive Disability Plan, which provides short-term disability coverage, a long-term disability (LTD) plan, and the Return to Work Program, which assists employees in finding other jobs if a disability prevents them from performing their usual work.[1221]

SCE provided five years of historical expenses, which range from a low of $18.213 million in 2008 to a high of $24.510 million in 2009. SCE says in its Direct testimony that a new vendor created a backlog of LTD claims in 2006, and a service improvement plan implemented in late 2006 eliminated the backlog in 2007, which means that some 2006 claims were not paid until 2007, thus falsely deflating the 2006 expense and falsely inflating the 2007 expense. The extra effort in 2007 then carried over as lower costs for 2008.[1222] SCE claims that the 2009 increase may be due in part to an increased employee population, but concedes that the apparently routine variations in LTD claim activity might also be a factor.[1223]

[1219] D.09-03-025, p. 143.

[1220] Ex. DRA-15, p. 2, Table 15-1.

[1221] Ex. SCE-06, Volume 2, Ch. VII, pp. 84-86.

[1222] Ex. SCE-06, Volume 2, Ch. VII, pp. 87-88.

[1223] Ex. SCE-06, Volume 2, Ch. VII, pp. 87-88.

Due to the fluctuation, DRA believes that the five-year average of $21.034 million provides a more accurate basis for forecasting the 2012 test year expense. DRA continues to recommend a test year disability programs expense of $23.40 million.

8.6.3.4. Group Life

SCE seeks ratepayer funding in the amount of $1.85 million for Group Life costs for the test year. DRA recommends ratepayer funding of no more than $0.99 million.[1224]

SCE offers five separate types of coverage: Employee Life Insurance, Dependent Life Insurance, Accidental Death & Dismemberment (AD&D), and Business Travel Insurance. The Company provides a basic level of both Employee Life Insurance coverage and AD&D, and provides Business Travel insurance for employees traveling on SCE business; employees may purchase supplemental life insurance, Dependent Life Insurance, and supplemental AD&D coverage for their spouse and/or children.[1225] SCE also provides Paid-Up Life Insurance to approximately 88 employees who elected this coverage prior to August 1, 1983.[1226]

SCE forecasts an escalation rate of 60% for 2010 due to increased costs from "a significant increase in the company provided basic benefit for both Life Insurance and Accidental Death and Dismemberment coverage."[1227] DRA objects to this escalation rate. SCE's proposal to increase benefits for its own employees at the expense of its ratepayers is yet another example of SCE's complete failure to make any attempt to rein in its costs. SCE's ratepayers are struggling to pay their own bills and, as some of SCE's ratepayers have pointed out, SCE should make similar efforts to live within its budget.[1228]

DRA recommends the exclusion of SCE's escalation rates for Group Life Insurance. Along with DRA's different labor estimate, this results in a test year expense of $989,000, an adjustment of $861,000.

[1224] Ex. DRA-15, p. 2, Table 15-1.

[1225] Ex. SCE-06, Volume 2, Ch. VII, pp. 89-91

[1226] Ex. SCE-06, Volume 2, Ch. VII, p. 91

[1227] Ex. SCE-06, Volume 2, workpapers Pt. 2, Ch. VII, p. 211.

[1228] See*, e.g.*, 1 RT 31 (PPH/ San Bernardino)

8.6.3.5. Miscellaneous Benefits – Preventive Health and Work/ Life Programs

SCE includes Health Resources expenses and Work/ Life Initiative expenses in its request for ratepayer funding of "Miscellaneous Benefits."[1229] SCE says its Health Resources expenses include services such as "Company Wellness Programs with Web MD, Health Initiative Program, and Plan Chooser Tool."[1230] SCE says the Work/ Life Balance Initiatives is important to "recruit and retain employees, and provides benefits to SCE customers through enhanced employee engagement."[1231] DRA opposes ratepayer funding of these programs.

In SCE's workpapers for this GRC, there is no breakdown of costs into the "Final Cost Centers" for Miscellaneous Benefits, only a total cost is booked to the Miscellaneous Benefits final cost center. When DRA inquired about this, SCE's response was that these costs were no longer tracked to cost centers.[1232] As there is no breakdown of costs in Miscellaneous Benefits in this GRC, DRA removed the historical cost from the 2009 GRC, $273,000 for preventive health and $554,000 for work/life, from the base year program expense.

In the TY 2009 GRC, SCE requested, and was granted, costs for preventive health and work/life programs. In the last GRC, DRA opposed ratepayer funding of the Preventive Health and Work Life programs as duplicative and/or supererogatory. DRA continues to do so here.

In its Direct testimony, SCE describes the Health Resources programs in its Miscellaneous Benefits as including such things as "information about the company's benefit programs..." and an online website "[t]o support more informed health care treatment decisions, identify patients with significant medical risks for intervention by the medical plans and encourage modification of lifestyle behaviors such as obesity, poor fitness, smoking and high stress."[1233]

These programs still sound duplicative to DRA. SCE already gets ratepayer funding for its Human Resources Department, which can provide information about the Company's benefits

---

[1229] Ex. SCE-21, pp. 71-73.

[1230] Ex. SCE-21, p. 72.

[1231] Ex. SCE-21, pp. 73-74.

[1232] Ex. DRA-15, p. 18.

[1233] Ex. SCE-06, vol. 2, p. 96.

programs. SCE already gets ratepayer funding for medical plans which generally include programs that encourage modification of lifestyle behavior problems.[1234]

SCE describes its Work/ Life program as providing help to SCE employees in finding ways to balance work with family life, such as child and elder care services, emergency dependent care, specialized school services, college and financial planning, and other legal, health, and wellness resources. This supererogatory benefit program does not provide a clear and identifiable benefit to ratepayers, and is not necessary to operate the utility business.

DRA recommends zero ratepayer funding of these programs. If SCE wants to provide these programs to its employees, it can do so at its shareholders' expense.

8.6.3.6. Executive Benefits

SCE's forecast of Executive Benefits expense for the Test Year is $17.0 million.[1235] DRA recommends zero ratepayer funding of Executive Benefits.[1236]

SCE offers certain executives supplemental benefits which include the Supplemental Executive Retirement Plan (SERP), and the Supplemental Survivor and Disability benefit programs.[1237] DRA opposes the inclusion of any Supplemental Executive Benefits in revenue requirements. SCE's argument that the total compensation provided to its executives is below market is meaningless. SCE is entitled to provide any supplemental benefits it wishes to its executives, but ratepayers should not be required to bear the costs of those that exceed either what is authorized by the tax code and other pertinent laws and regulations, or what is offered as part of SCE's normal employee coverage.

In Rebuttal, SCE argues that, "[n]ot having any real reason to oppose the inclusion of any expense for Executive Benefits for the test year revenue requirements, DRA now attacks the Total Compensation Study, which it jointly sponsored with SCE...",[1238] SCE is mistaken.

First, DRA is not a sponsor of the Total Compensation Study as discussed in more detail in Section 8.5.1. above. Second, DRA's testimony sets forth the reasons it opposed inclusion of expense for executive benefits when it appeared SCE was seeking them for 31 select employees.

[1234] Ex. DRA-15, p. 19.

[1235] Ex. SCE-06, Volume 2, p. 97.

[1236] Ex. DRA-15, p. 19.

[1237] Ex. SCE-06, Volume 2, Ch. VII, p. 98

[1238] Ex. SCE-21, p. 75.

Now it appears that SCE is steadily increasing the number of executives who will benefit from these plans at ratepayer expense. What was 36 executives in SCE's last GRC[1239] became 182 at the time of the Total Compensation Study, and is now up to 222.[1240] Far from making any effort to contain its costs, SCE seems determined to increase them.

DRA recommends that the entire $17.0 million SCE forecasts for Executive Benefits be removed.

- **Supplemental Executive Retirement Plan**

When DRA prepared its testimony, DRA was under the impression that SCE provided the Supplemental Executive Retirement Plan (SERP) only to a select group of the 31 executives designated by that title in the Total Compensation Study. As it turns out, it seems that SCE is actually proposing that ratepayers fund the costs of supplemental benefits to *222* "executives."

SCE says that it's Executive Retirement Plan "restore[s] benefits that executives cannot receive in the qualified SCE Retirement Plan due to limits the Internal Revenue Code has imposed."[1241] Unlike the qualified Retirement Plan, the Executive Retirement Plan calculates benefits based on salary *and bonuses*.[1242]

In the present economic circumstances, zero ratepayer funding is the only reasonable approach. This approach has been used by Commissions in other jurisdictions. In 2008 in Arizona, for example, the commission there held that, if Southwest Gas Company wished to provide a Supplemental Executive Retirement Plan to select executives, then shareholders, rather than ratepayers, should be responsible for those benefits.[1243] In 2009, the Connecticut Department of Utility Control held that, "ratepayers should not have to fund excessive benefits that are over and above the IRS code, particularly in these difficult economic times."[1244] In 2010, the Washington Utilities and Transportation Commission in a Puget Sound Energy rate

---

[1239] D.09-03-025, mimeo, p. 135, footnote 409.Ex.

[1240] Ex. SCE-33, ALJ Darling –SCE-002, Q. 1.

[1241] Ex. SCE-06, Vol. 2, Ch. VII, p. 99.

[1242] Ex. SCE-06, Vol. 2, Ch. VII, p. 99.

[1243] In the Matter of the Application of Southwest Gas Corporation (2008) D.70665; 2008 Ariz PUC LEXIS 237 *30 citing In the Matter of the Application of Arizona Public Service Company *(2007)* D.69663; 2007 Ariz. PUC LEXIS 126 *52.

[1244] Application of Connecticut Natural Gas Corporation (2009) Docket No. 08-12-06; 2009 Conn. PUC LEXIS 117*130.

case, recommended removal of supplemental retirement costs for executives who "already are highly compensated and entitled to the same levels of qualified retirement plan benefits as other employees, within the limits of what the IRS allows."[1245]

In Rebuttal, SCE cites to a number of cases from other jurisdictions that have allowed ratepayer of supplemental retirement benefits to executives. From DRA's review of SCE's citations, the oldest is from 1985, the most recent from 2006.[1246] None of these decisions was issued after the collapse of the real estate market in 2008 that has led to the greatest economic crisis in recent history.

In its decision in SCE's TY 2009 GRC, this Commission limited ratepayer funding of Executive Benefits to 50%.[1247] SCE has not explained what has changed since its last rate case to justify an *increase* in ratepayer funding to these already highly compensated executives.

On the contrary, recent events show why the Commission should eliminate ratepayer funding of these benefits altogether. On April 21, 2011, Peter Darbee, the President and CEO of PG&E for the past six years, announced his retirement[1248] and claimed a retirement package totaling nearly $35 million, including $9.6 million in pension benefits. Almost immediately, state officials including Governor Jerry Brown[1249] stated that Mr. Darbee's pension should be funded by shareholders, not ratepayers. On April 25, 2011, PG&E's board of directors agreed to that, voting to amend Mr. Darbee's retirement package to be funded fully by shareholders. The board's Lead Director, Lee Cox explained, "Today's decision is [an] opportunity to show customers, regulators and others that PG&E is listening closely and taking action to earn back their confidence."[1250] PG&E's board of directors recognized that forcing ratepayers to fund excessive retirement payouts is wrong, and the Commission should recognize that, also.

[1245] *Washington Utilities and Transportation v Puget Sound Energy*, Inc. (2010), Dockets UE-090704 and UG-090705 (consolidated), Order 11; 2010 Wash. UTC LEXIS 279*64.

[1246] Ex. SCE-21, pp.78- 79.

[1247] D.09-03-025, mimeo, p. 146. "[B]ecause these executive benefits are largely tied to the amount of compensation awarded the executive, we find including 50% of this forecast in rates reasonable after reducing the total amount by one officer."

[1248] Ex. DRA-15, p. 21, citing http://www.bizjournals.com/sanfrancisco/news/2011/04/21/pge-ceo-peter-darbee-retires.html.

[1249] Ex. DRA-15, p. 21, citing http://abcnews.go.com/Business/wireStory?id=13455226.

[1250] Ex. DRA-15, p. 22, citing http://www.pge.com/about/newsroom/newsreleases/20110425/pgampe_shareholders_to_pay_pension_benefits_for_retiring_ceo.shtml.

This policy should apply across the board to all highly compensated employees in addition to the highest compensated employee. For all these reasons, DRA continues to recommend zero ratepayer funding for SERP.

- **Supplemental Survivor and Disability Benefit Programs**

SCE's Supplemental Survivor Benefit plan "provides to the survivor of an eligible executive who dies in-service a benefit that is equal after taxes to the executive's annual salary (plus bonus if the executive is an elected vice-president or higher ranking officer.)"[1251] The supplemental disability plan keeps an executive who is out on disability "at full salary up to the one-year anniversary of the onset of the disability."[1252] Unlike the life insurance and disability programs offered to rank and file employees, these programs provide a full salary benefit, for a longer period of time, and at no additional cost to the executive.[1253]

As part of SCE's Group Life insurance plan, which is included in rate recovery, employees are provided with the opportunity to purchase life insurance which provides income to the employee's beneficiary upon death. Most full-time employees receive enough "FlexDollars" to pay for company-provided employee life insurance equal to their annual base salary, up to $50,000, and employees can purchase additional coverage, up to eight times their annual base salary, at their own cost.[1254]

Ratepayers already contribute a reasonable amount to provide income security to the survivors of deceased employees and retirees, and there is no reason that ratepayers should be required to provide even more funding to further supplement benefits to a small number of high-level SCE employees. It is inappropriate to burden ratepayers by requiring them to provide duplicative funding for the executive supplemental program. SCE provides no justification for ratepayer funding of these supplemental programs. If SCE wants to provide this benefit to its executives, it can do so at shareholders' expense. DRA recommends that SCE not be allowed to recover from ratepayers any costs related to this program.[1255]

[1251] Ex. SCE-6, Vol. 2, p. 100.

[1252] Ex. SCE-6, Vol. 2, p. 100.

[1253] Ex. DRA-15, p. 22.

[1254] http://www.edison.com/files/sce_benefits.pdf.

[1255] Ex. DRA-15, p. 23.

9. Administrative and General

SCE is requesting a total of $311.487 million in Test Year 2012 expenses, which is an increase of $74.546 million or 31.5% over SCE's 2009 recorded adjusted expenses of $236.94 million. DRA recommends ratepayer funding of a total of no more than $234.589 million for the Test Year.[1256]

9.1. Financial Organizations

SCE's Financial Organizations include its Controller's Organization, Audit Services Department, Treasurer's Department, and Tax Department. For these Financial Organizations, SCE is requesting a total of $79.644 million in Test Year 2012 expenses, a 10.9% increase from 2009 Adjusted Recorded costs of $71.823 million.[1257]

9.1.1. Controller's Organization

SCE's Controller's Organization is forecasting $51.76 million for Test Year 2012 expenses.[1258] SCE's Controller's Organization used 2009 recorded method for labor and non-labor to forecast for Test Year 2012. DRA's Test Year 2012 expense forecast is $35.257 million.[1259]

9.1.1.1. Controller's Organization Account 920/ 921

During the record period, 2005 to 2009, the Controller's Organization labor costs increased 6.2%.[1260] SCE says the increase in labor costs in 2009 is attributable to staff assigned to Enterprise Resource Planning (ERP) project returning to the Controller's Organization, the addition of six positions, and the filling of vacancies. In addition, SCE says its Controller's Organization reduced its reliance on contractors, and made other organizational changes.[1261]

The Controller's Organization forecast its labor costs for Test Year 2012 using recorded 2009 as the base, and reducing that by $200,000 to reflect SCE's "expected labor needs that are consistent with the organizational structure implemented in 2009."[1262]

[1256] Ex. DRA-12-R, p. 6, Table 12-1 Revised.

[1257] Ex. DRA-12-R, p. 9.

[1258] See Ex. SCE-7, Vol. 1, p. 13.

[1259] Ex. DRA-12-R, p. 10.

[1260] Ex. SCE-7, Vol. 1, p. 19.

[1261] Ex. SCE-7, Vol. 1, pp. 19-20.

[1262] Ex. SCE-7, Vol. 1, p. 20.

DRA reviewed this forecast for labor costs and, in its testimony, recommended that a forecast for Test Year 2012 be based on a five year average.[1263] Using a five year average takes into consideration the variance in labor costs over the record period and the changes implemented in the Controller's Organizational structure during 2009.

In Rebuttal, SCE says that "DRA correctly observes that 'Labor costs did not vary significantly from year to year,'" and that, therefore, according to the forecasting principles of D.89-12-057, DRA should not have used an average to forecast the Test Year.[1264] SCE then includes a chart showing the Controller's Labor Expenses, Recorded Adjusted for the years 2005-2009, and SCE's and DRA's TY 2012 forecasts.

SCE's graph of its Controller's Organization costs shows, in fact, that SCE's labor costs *did* vary from year to year, going from $16.0 million in 2005, to $15.9 million in 2006 to $15.0 million in 2007 to $15.3 million in 2008 and then spiking up to $16.9 million in 2009.[1265] DRA continues to recommend a TY 2012 forecast for labor costs of $15.906 million.[1266]

For non-labor costs, the Controller's Organization forecast for Test Year 2012 is $2.750 million.[1267] SCE uses 2009 recorded data as the base estimate and reduces it by $475,000 to reflect a decline in temporary agency personnel needed for the Accounts Payable function.[1268]

DRA reviewed SCE's forecast and recommends that Test Year 2012 non-labor expenses be based on a five year average. SCE's non-labor costs were highest in 2006 and 2009. There were minor increases in non-labor costs in 2007 and 2008. Using a five year average takes into consideration the variance in non-labor costs over the record period and the changes implemented in the Controller's Organizational structure during 2009. DRA 2012 forecasts $2.665 million for non-labor costs.[1269]

[1263] Ex. DRA-12-R, p. 12.

[1264] Ex. SCE-22, Vol. 1, p. 3.

[1265] Ex. SCE-22, vol. 1, p. 4, Figure II-1.

[1266] Ex. DRA-12-R, p. 12.

[1267] Ex. SCE-07, Vol. 1, p. 19, Figure II-1.

[1268] Ex. SCE-07, Vol. 1, p. 20.

[1269] Ex. DRA-12-R, p. 12.

9.1.1.2. Controller's Organization Account 923

For TY 2012, the Controller's Organization is seeking $31.783 million in ratepayer funding for costs associated with Outside Services.[1270] DRA recommends ratepayer funding of no more than $16.258 in the Test Year.[1271]

The reasons for DRA's recommendation are set forth in detail in the confidential version of DRA's A&G Testimony and include removal of certain tax consulting costs from the record period,[1272] as well as rejection of costs associated with the "IFRS project."[1273]

9.1.1.3. Controller's Organization Account 926

DRA does not dispute SCE's forecast for this account.

9.1.1.4. Controller's Organization – Capitalized Software

The Controller's Organization is also requesting a total of $14.5 million in capital expenditures $2.9 million for 2012 and $11.6 million for 2013, for a capitalized software project, which SCE says is to comply with International Financial Reporting Standards (IFRS).[1274] DRA recommends zero ratepayer funding for this project.[1275]

SCE's estimate was based on a survey conducted by Accenture "...of companies with revenue between $5.0 billion and $9.9 billion [which] estimates the cost of conversion to IFRS will be approximately 0.298 percent of annual revenue."[1276] SCE then multiplied this 0.298 percent by SCE's 2009 annual revenue of $9.746 billion to come up with an estimated IFRS total implementation cost of $29.0 million for SCE. SCE then used a "50 percent factor of technology costs" to come up with its $14.5 million estimate.[1277]

None of these calculations, however, shows why SCE needs this funding for this project in this rate case. SCE's supporting workpapers for this project consisted of a single page[1278]

[1270] Ex. SCE-07, Vol. 1, p. 21.

[1271] Ex. DRA-12-R, p. 14.

[1272] Ex. DRA-12-C-R, p. 13; Ex. SCE-21, Vol. 1, p. 8.

[1273] Ex. SCE-21, Vol. 1, p, 7.

[1274] Ex. SCE-22, Vol. 1, p. 27.

[1275] Ex. DRA-12-R, p. 22.

[1276] Ex. SCE-7, Vol. 1, p. 49.

[1277] Id.

[1278] Ex. DRA-12, p. 22 citing SCE workpapers for Exhibit SCE-07, Volume 1, Chapter VIII, p. 197.

which is insufficient documentation to review and analyze.[1279] Moreover, SCE does not expect to solicit vendor bids for this IFRS project until after the Securities and Exchange Commission (SEC) issues its implementation rules for IFRS.

DRA continues to recommend no ratepayer funding for this project.

9.1.2. Audit Services

SCE's Audit Services Department is forecasting $10.285 million for the Test Year 2012.[1280] This represents an overall increase of 12.9% over 2009 Adjusted Recorded costs of $9.106 million. DRA's Test Year 2012 forecast is $9.033 million.

Audit Services forecast increase is due to filling five vacancies, adding two additional Information Technology auditors, experts or consultants to train auditors in specialized technical areas, and increased travel costs associated with non-utility company audits.

9.1.2.1. Audit Services Account 920

For TY 2012, Audit Services is forecasting $8.452 million in labor costs. This is an increase of $629,000,[1281] over recorded 2009 expenses. Of that, $401,000 is to fill five vacancies, and $228,000 is for two additional Information Technology Auditors. DRA's 2012 forecast is $7.704 million for labor costs.

SCE claims that Audit Services "needs to be at full staff in 2010 in light of increased work due to items such as Edison Smart Connect™, NERC/CIP cyber-security requirements, energy trading, and emerging environmental regulations (e.g., Green House Gas emissions)."[1282] DRA reviewed Audit Services staffing levels for the record period, 2005-2009.[1283] In light of SCE's staffing levels during this period, and given the lack of specificity as to what the additional auditors would actually be doing that SCE's existing staff cannot, DRA considers that Audit Services has not justified a need for seven additional auditors.[1284] Therefore, DRA recommends that $629,000 be removed from Test Year 2012 forecast.

[1279] Ex. DRA-12, p. 22 citing Response to DRA-SCE-061-DFB, Q/A 1a-e.

[1280] Ex.SCE-7, Vol. 1, p. 24.

[1281] Ex. SCE-7, Vol. 1, p. 27.

[1282] Id.

[1283] Ex. DRA-12-R, p. 14, citing confidential response to DRA-SCE-056-DFB, Q/A 2.

[1284] The staffing levels are set out in Ex. DRA-12-C-R, p. 15.

SCE forecast Audit Services labor costs using 2009 recorded as the basis for estimating Test Year 2012, to which it then added the incremental labor cost of $629,000 discussed above. DRA disagrees with SCE's method of forecasting.

SCE's Audit Services labor costs have fluctuated in minor amounts over the record period 2005-2009. DRA recommends using a five year average to forecast the labor costs for the Test Year 2012.[1285] In Rebuttal, SCE refers to D.87-12-057 and argues that this decision validates SCE's use of the last recorded year because SCE's recorded expenses were "stable."[1286]

In SCE's TY 2009 GRC, however, the Commission adopted DRA's forecast which was based on a five-year average. In doing so, the Commission noted that SCE's "expenses in years 2002-2006 have been relatively *stable*."[1287]

DRA considers forecasting to be a matter of judgment and, in DRA's judgment, and for the reasons set forth in DRA's testimony, DRA continues to recommend $7.704 million for SCE's Audit Services labor costs.

9.1.2.2. Audit Services Account 921

For non-labor costs, Audit Services is forecasting $1.833 million for the Test Year 2012. SCE used its 2009 recorded costs of $1.283 million as the basis for its estimate. To that base, SCE added incremental non-labor costs of $550,000. DRA disagrees with SCE's method of forecasting and recommends the Commission adopt a forecast of $1.39 million for non-labor costs for Audit Services.

Non-labor costs are related to the amount of labor costs. Consistent with DRA's proposal to disallow SCE's requested increase in labor costs DRA removed the $550,000 for non-labor incremental costs SCE added to its 2009 recorded amounts costs. In light of the fact that SCE's non-labor costs have fluctuated in minor amounts over the record period, DRA recommends using a five year average to forecast the Test Year.[1288]

[1285] Ex. DRA-12-R, p. 15.

[1286] See Ex. SCE-22, Vol. 1, p. 10.

[1287] D.09-03-025, mimeo, p. 162, emphasis added.

[1288] Ex. DRA-12-R, p. 16.

9.1.3. Treasurer's Department

SCE's Treasurer's Department forecasts a total of $13.667 million for the Test Year 2012.[1289] This represents a 43.5% increase over SCE's 2009 Adjusted Recorded costs of $9.527 million.[1290] The increases SCE proposes over its 2009 recorded amounts are $484,700 in labor costs for five new positions, $32,000 in non-labor costs, and $3.283 million for banking and operating fees.[1291]

DRA's Test Year 2012 forecast is $12.683 million.

9.1.3.1. Treasurer's Department Account 920

The Treasurer's Department seeks to increase labor costs by $484,700 to fill two vacancies and three additional positions. SCE says this is to "...respond to additional work resulting in large part from SCE's unprecedented capital investment program."[1292]

SCE has provided insufficient justification for the addition of these positions. As in SCE's last GRC, when it sought to add new positions, SCE offers only the vaguest explanation of why it needs increased staff. Nowhere does SCE set out a ratio of people per projects, or explain how the "additional work" translates into actual labor hours. In the last GRC decision, the Commission rejected SCE's requested increase in labor costs because SCE did not "...quantify the extent to which these activities will rely on additional staff."[1293] DRA recommends the Commission do the same in this GRC.

SCE forecasted labor costs for its Treasurer's Department using recorded 2009 expenses as the base, and then adding the $484,700 for additional positions, which are discussed above. DRA disagrees with this method of forecasting. SCE's labor costs have fluctuated in minor amounts over the record period 2005-2009. DRA recommends using a five year average to forecast the labor costs for the Test Year 2012.[1294]

DRA continues to recommend a TY 2012 forecast of $4.05 Million for labor costs.

[1289] Ex. SCE-7, Vol. 1, p. 29.

[1290] Ex. SCE-7, Vol. 1, p. 29.

[1291] Ex. SCE-7, Vol. 1, p. 39, as revised by Ex. SCE-22, Vol. 1, p. 19.

[1292] Ex. SCE-7, Vol. 1, p. 34.

[1293] D.09-03-025, mimeo, p. 163.

[1294] Ex. DRA-12-R, p. 17.

9.1.3.2. Treasurer's Department Account 921

SCE forecasts $531,000 in non-labor costs for its Treasurer's Department in the Test Year. SCE says its forecast for non-labor costs uses the recorded 2009 expense level of $499,000 as the base. According to SCE, non-labor costs "are approximately 11% of the labor costs."[1295] To the base, SCE added incremental non-labor costs of $32,000.

DRA reviewed SCE's method of forecasting and disagrees with it. DRA's 2012 forecast is $444,000 for non-labor costs.

Non-labor costs are related to the amount of labor costs. Consistent with DRA's proposal to disallow SCE's requested increase in labor costs DRA removed the $550,000 for non-labor incremental costs SCE added to its 2009 recorded

Non-labor costs are related to the amount of labor costs. DRA's recommended adjustment to the Treasurer's Department labor costs has an impact on the forecast of the Treasurer's non-labor costs. DRA recommends using a five year average to forecast the labor costs for the Test Year 2012. After removing the $32,000 for non-labor incremental costs and using a five year average forecasting method, this results in the Test Year 2012 forecast of $444,000. DRA recommends reducing non-labor 2012 forecast by $87,000.[1296]

9.1.3.3. Treasurer's Department Account 930

Costs charged to Account 930 include bank service operating fees, credit line operating fees, and bond-related fees. SCE's Treasurer's Department used a budget based methodology to forecast bank fees, credit line fees and bond-related fees in the amount of $7.852 million for the Test Year.[1297] DRA's 2012 forecast is $4.924 Million for bank fees costs.

DRA reviewed SCE's budget-based forecast and disagrees with it as speculative and unsupported by any verifiable evidence. SCE's costs have fluctuated in minor amounts over the record period 2005-2009. In 2010, SCE's recorded costs were $4.889 million.[1298]

DRA recommends using a five year average (2006-2010) to forecast these costs for the Test Year 2012. This results in a reduction to SCE's TY forecast of $3.268 million.[1299]

[1295] Ex. SCE-7, Vol. 1, p. 35.

[1296] Ex. DRA-12-R, p. 18.

[1297] Ex. SCE-22, Vol. 1, p. 19.

[1298] Ex. DRA-12-R, p. 19, citing Response to DRA-SCE-237-DFB, Q/A 3.

[1299] Ex. DRA-12-R, p. 19.

9.1.4. Tax Department

SCE's Tax Department forecasts $3.932 million for Test Year 2012 based on the use of SCE's last recorded year expenses for labor and non-labor costs.[1300] This represents an overall increase of 16.8% over 2009 Adjusted Recorded costs of $3.365 million. DRA's 2012 forecast is $2.942 million.[1301]

9.1.4.1. Tax Department Account 920

SCE's Tax Department forecasts $3.378 million in labor costs for the Test Year. This is an increase of $567,000 over 2009 recorded labor costs.[1302] DRA recommends $2.622 million for the Test Year.[1303]

SCE's says its proposed increase in labor costs for the Test Year 2012 is to fill two vacancies and add two new positions.[1304] SCE says that, during 2009, outside consultants were used to temporarily backfill the vacant positions.[1305] The cost of the outside consultants was $280,000[1306] and is included in an adjustment to the Tax Department's recorded 2009 labor.[1307] SCE then adds $336,000 to the 2009 base year "to fill two vacancies."[1308]

By including both the costs of backfilling the vacancies, and the full costs of filling the vacancies in the forecast, SCE is double-counting the costs of these vacancies in the Test Year. DRA recommends that $336,000 be removed from the Test Year 2012 forecast.[1309]

In Rebuttal, SCE says it was not double-counting, but that its testimony and workpapers "could have contributed to DRA's confusion on this issue."[1310] SCE now says it had four

---

[1300] Ex. SCE-7, Vol. 1, p. 13.

[1301] Ex. DRA-12-R, p. 19.

[1302] Ex. SCE-22, Vol. 1, p. 23.

[1303] Ex. DRA-12-R, p. 21.

[1304] Ex. SCE-7, Vol. 1, p. 44.

[1305] Id.

[1306] Ex. DRA-12-R, p. 20, citing Response to DRA-SCE-060-DFB, Q/A 3.

[1307] Ex. DRA-12-R, p. 20, citing workpapers for Exhibit SCE-07, Volume 1, Chapter VII, page 193, Business Adjustment 2.

[1308] Ex. DRA-12-R, p. 20, citing workpapers for Exhibit SCE-07, Volume 1, Chapter VII, page 183.

[1309] Ex. DRA-12-R, p. 21.

[1310] Ex. SCE-22, Vol. 1, p. 24.

incremental positions over 2009 recorded-adjusted amounts.[1311] This information comes too late for DRA to verify it, and DRA continues to recommend removal of the entire $566,800.

In any event, in its Direct testimony, SCE says: "The *two* new tax positions will support the following activities: (1) monitoring and complying with changing federal and state laws and regulations as mentioned above, (2) preparing schedules to meet additional IRS audit scrutiny and increased filing requirements, including Schedule UTP (for uncertain tax positions, as described below), (3) meeting increased Sarbanes-Oxley requirements in the tax area, and (4) complying with current accounting standards for computing income taxes under FIN 48."[1312]

DRA specifically asked SCE how it determined the need for two new tax positions, to which SCE replied: "The need for the two new tax positions was based primarily on hours spent by outside consultants to complete these duties when there were new filing requirements in prior years."[1313] Since SCE has provided no quantitative justification for the need for two new tax positions, DRA recommends that $231,000 in labor costs be removed from Test Year 2012 forecast.

In forecasting its labor costs for the Test Year 2012, SCE's Tax Department used 2009 recorded expenses as its basis to which it then added the $566,800 discussed above to arrive at its labor forecast of $3.378 million. DRA disagrees with this forecasting method here and recommends the use of a five-year average. SCE's labor costs have fluctuated from $1.346 million in 2005 to $1.742 million in 2009, with the highest in 2007 of $1.949 million. DRA forecasted labor costs in the Tax Department using a five year average (2005-2009). DRA's 2012 forecast is $2.622 million for labor costs.

In Rebuttal, SCE says that "DRA's proposal is contrary to the guidance of D.89-12-057, which endorses averaging when accounts have 'significant fluctuations in recorded expenses from year to year.'"[1314] As noted above, in deciding SCE's last GRC, the Commission found a five-year average a reasonable basis for a forecast when recorded expenses were stable. Thus, whether a particular method is reasonable is a matter of judgment. In DRA's judgment, the fluctuations in expenses in this area merit using a five-year average. In SCE's judgment, there

---

[1311] Ex. SCE-22, Vol. 1, p. 24.

[1312] Ex. SCE-7, Vol. 1, p. 45, emphasis added.

[1313] Ex. DRA-12, p. 21, citing Response to DRA-SCE-060-DFB, Question 4.

[1314] Ex. SCE-22, vol. 1, p. 22.

have not been significant fluctuations; expenses have been "stable. The Commission has used a five year average in both circumstances, and DRA recommends it do so here as well.

9.2. Risk Control

SCE's Risk Control Group is requesting $6.055 million in Test Year 2012 expenses, an increase of $715,000 from 2009 recorded costs. DRA's 2012 forecast for this area is $3.847 million.[1315]

9.2.1. Risk Control Group Account 920

For its Risk Control Group, SCE forecasts labor costs of $4.945 million in Test Year 2012. This is an increase of $655,000 over SCE's recorded 2009 labor costs of $4.290 million. SCE says the $655,000 increase is to fill five vacancies and hire one additional employee for the Test Year 2012.[1316] DRA recommends removing $655,000 from Test Year 2012 forecast, and using a five-year average of recorded costs for a TY 2012 forecast of $2.8853 million in labor costs.[1317]

First, SCE has not provided sufficient quantitative justification for the increase in Risk Control labor costs. Generalizations about changes in the energy markets over the last several years do not explain what specific projects require in the way of additional staff or why SCE's current staff cannot handle these projects. DRA therefore recommends the $655,000 be removed for forecasting purposes.

SCE used a budget-based method to forecast $4.945 million for its Risk Control labor costs for Test Year 2012. DRA disagrees with SCE's method as speculative and unreliable, and recommends using a five year average. Using a five year average takes into consideration the variance in labor costs over the record period. DRA forecasts $2.853 million for labor costs for Test Year 2012.

9.2.2. Risk Control Group Account 921

SCE forecasts non-labor costs of $456,000 for its Risk Control Group in Test Year 2012. DRA recommends $339,000.[1318]

[1315] Ex. DRA-12-R, p. 6, Table 12-1, Revised.

[1316] Ex. SCE-7, Vol. 1, p. 70.

[1317] Ex. DRA-12-R, p. 23.

[1318] Ex. DRA-12-R, p. 24.

SCE used a budget-based method to forecast $456,000 for the non-labor costs of the Risk Control Group for Test Year 2012. DRA disagrees with the use of this method here as well.

Non-labor costs are related to labor costs, and DRA's disallowance of SCE's proposed increase in labor costs is, in part, the reason for DRA's lower forecast for non-labor costs. DRA also recommends that the forecast for the Test Year 2012 be based on a five year average. DRA believes that using a five year average takes into consideration the variance in SCE's recorded non-labor costs over the record period.

In Rebuttal, SCE says that the spike in 2007 in its recorded non-labor costs was due to the erroneous inclusion of a one-time cost in that year.[1319] Apparently, SCE includes this information in its Rebuttal to argue that, if the one-time cost were removed, SCE's view of its non-labor costs as being on an upward trend would be validated. In fact, removing that one-time cost shows SCE's non-labor costs level off between 2008 and 2009.[1320]

DRA continues to recommend the Commission adopt a 2012 forecast of $339,000 for non-labor costs for SCE's Risk Control Group.

9.3. Law Department

In its Direct testimony, SCE's forecast for its Law Department (including the Corporate Governance Division) Administrative and General expenses was $47.829 million for the Test Year 2012.[1321] In Rebuttal, SCE revised this A&G forecast to $46.064 million.[1322] DRA recommends ratepayer funding of no more than $39.713 million.[1323]

9.3.1. In –House Resources

SCE's Law Department handles the majority of SCE's legal matters in-house. SCE's Law Department is forecasting TY 2012 labor expenses of $24.682 million.[1324] This represents an increase of $1,716,300 over SCE's 2009 recorded costs.

The increase SCE seeks is for the addition of nine attorneys, three paralegals, and three legal administrative assistants. SCE has provided insufficient justification for the requested

---

[1319] See Ex. SCE-22, Vol. 1, p. 36.

[1320] Ex. SCE-22, Vol. 1, p. 38.

[1321] Ex. SCE-7, Vol. 2, p. 3.

[1322] Ex. SCE-22, Vol. 2, p. 1.

[1323] Ex. DRA-12-R, p. 26, Table 12-16.

[1324] Ex. SCE-22, Vol. 2, p. 2.

increase and DRA recommends it be denied. DRA recommends SCE's Law Department labor costs for TY 2012 be held at 2009 recorded levels or $22.966 million.[1325]

In its Direct testimony, SCE says that: "The Department anticipates an increased workload for all attorneys due to the implementation of the new Energy Regulatory Compliance Program (ERCP)."[1326] If the workload for all attorneys is increasing due to ERCP then SCE should be able to provide a quantitative support for the increase in staff for the Test Year 2012.

SCE's Direct Testimony also says that "…the Renewable and Alternative Power Department will have to contract to meet increased Renewable Portfolio Standard program goals (from 20 percent in 2010 to 33 percent in 2020)…"[1327] SCE did not provide any estimates to quantify how meeting the Renewable Portfolio goals will affect the Law Department costs in the Test Year 2012. Again, SCE's justification lacks any quantitative support to substantiate the forecast increase of labor costs.[1328]

In Rebuttal, SCE says "DRA has virtually ignored the testimony and voluminous data request responses in which SCE explains the need for the nine additional attorneys and six support staff forecast by the Law Department."[1329] SCE has confused volume with content. DRA reviewed the testimony and data requests on this subject and has found little of substance in any of them. A perfect example can be found in one of the data request responses SCE attached to its Rebuttal testimony. This particular data request asked SCE how it determined that there will be an increase in workload.[1330] SCE provided a chart and three pages of text that refers to "unprecedented" volumes of work, requiring "substantial" legal assistance, but never quantifies how this translates into attorney or support staff hours. SCE also includes what it calls a "study" that is supposed to show "the need for legal services associated with large transmission and other related capital costs"[1331] but that series of charts and lists offers no way of correlating additional staff to actual work.

[1325] Ex. DRA-12-R, p. 27.

[1326] Ex. SCE-7, Vol.2, p. 4.

[1327] Ex. SCE-7, Vol. 2, p.11.

[1328] Ex. DRA-12-R, p. 26.

[1329] Ex. SCE-22, Vol. 2.

[1330] Ex. SCE-22, Vol. 2, Appendix A, p. A-1.

[1331] See 19 RT3082, Swartz/ SCE; Ex. SCE-22, Vol. 2, p. A-11 – A-16, A-31.

The fact that SCE' Law Department does not track its time may be part of the problem.[1332] That is SCE's choice, however. If SCE's Law Department chooses not to track its time, then SCE should find some other way of meeting its burden of proving that the current staffing levels in the Law Department are insufficient. SCE has not done so.

In the absence of any support for the proposed increase, DRA continues to recommend that the Commission use SCE's 2009 recorded expenses o forecast for the Test Year 2012.

Non-labor expenses are related to labor expenses. Since DRA is recommending no labor increases for the Test Year 2012, the forecasted non-labor expense also needs to be adjusted. DRA used 2009 recorded to forecast for the Test Year 2012, and recommends that Test Year 2012 non-labor forecast be reduced by $313,000. DRA's 2012 forecast is $4.191 million for non-labor costs.[1333]

9.3.2. Outside Counsel (duplicate)

In its Direct testimony, SCE forecasted $13.839 million for Test Year 2012 Outside Counsel costs. In Rebuttal, SCE revised this to $13.039 million for the Test Year.[1334] In its testimony, DRA recommends $4.492 million be removed from SCE's TY 2012 (original) forecast for SCE's Outside Counsel expenses in the Test Year.[1335]

SCE records expenses associated with its Outside Counsel costs in Account 923 – Outside Services -- and Account 928 -- Regulatory Commission Expenses.[1336] In Direct testimony SCE used 2009 recorded data for Account 923 and a four-year average for Account 928 to forecast Outside Counsel costs. In Rebuttal, SCE revised its Test Year 2012 forecast for Account 923 to $11.128 million and for Account 928 to $1.911 million.[1337]

SCE has negotiated fee arrangements with six firms that have been retained on a long-term basis for the bulk of legal services for SCE. In Direct testimony, SCE says its Outside Counsel Committee evaluates the performance of these six outside counsel firms and awards the

---

[1332] See 19 RT 3086, Swartz/ SCE.

[1333] Ex. DRA-12-R, p. 27.

[1334] Ex. SCE-22, Vol. 2, p. 7.

[1335] Ex. DRA-12-R, p. 30.

[1336] See Exhibit SCE-07, Volume 2, Chapter I, page 19.

[1337] Ex. SCE-22, Vol. 2, p. 7.

firms a bonus.[1338] As discussed in DRA's testimony, SCE fails to provide sufficient evidence that ratepayers derive any incremental benefit to justify the funding of these bonuses. SCE seems to assume, without justification, that it can look to the "deep pockets" of ratepayers for this type of expense. Ratepayers should not have to fund outside counsel bonuses on top of fees paid to for legal services provided to SCE. DRA recommends removing the outside counsel bonuses before forecasting for the Test Year 2012.[1339]

In Rebuttal, SCE says the "bonuses" it referred to in its Direct testimony are not really "bonuses," they are an "opportunity to earn back some or all of the discount depending on the arrangement made with the firm and the firm's performance."[1340] Whatever name SCE gives these payments, SCE still has not shown they benefit ratepayers. DRA continues to recommend they be removed.

SCE also included in Account 923 litigation costs for matters that DRA considers should not be charged to ratepayers.[1341] When an employment or discrimination case either results in a judgment against the utility or the utility chooses to settle such a case, the costs incurred by the utility should not be borne by the ratepayers. In 1980, FERC issued an Accounting Release (AR) 12 which specifically questions:

> "What is the proper accounting treatment for expenditures made by the utility, resulting from employment practices that were found to be discriminatory by a judicial or administrative decree or that were the result of a compromise settlement or consent decree?"

The FERC Release AR-12 answers the question by stating:

> "The Uniform System of Accounts provides that all charges to utility operating expense accounts must be just and reasonable. Expenditures of the nature mentioned above that can be readily identified and quantified should not be considered as just and reasonable charges to utility operations and should be classified to the appropriate nonoperating expense accounts."

To DRA's knowledge, this Commission has followed AR-12 since it was issued. In D.92549, the Commission decided to exclude from test year results all costs which SCE incurred in an affirmative action suit which the Commission assumed would shortly be settled, explaining

---

[1338] Ex. SCE-7, Vol. 2, p. 19, line 14.

[1339] Ex. DRA-12-C-R, p. 28.

[1340] Ex. SCE-22, Vol. 2, p. 8.

[1341] Ex. DRA-12-C-R, p. 28.

the position was in harmony with FERC in AR-12.[1342] In D. 96-01-011, the Commission, again held that costs incurred in meritorious employment discrimination suits should not be charged to ratepayers as they are non-operating expenses.[1343]

In Rebuttal, SCE "again requests that the Commission reconsider this position with regard to settlements of lawsuits… " saying that "[t]he mere fact that a plaintiff alleges discrimination by SCE should not preclude recovery of the costs associated with defending such a claim…[1344] SCE's argument has been considered, and appropriately rejected before. There is no good reason why the Commission should abandon its policy now. Therefore, DRA recommends that Account 923 Outside Services be reduced to exclude these costs.[1345]

DRA also recommends removal of the Navajo Nation Royalty Litigation for the reasons discussed in more detail below in Section 25, Audit.[1346]

9.3.3. Corporate Governance Account 930

In its Direct testimony, SCE forecast $4.091 million for Test Year 2012 Miscellaneous Expenses,[1347] for its Corporate Governance department. In Rebuttal, SCE revised this forecast to $3.135 million.[1348] DRA recommends the Commission adopt a TY 2012 forecast of $2.497 million.[1349]

EIX pays the Board of Directors fees and expenses for SCE the utility, and allocates some of those fees and expenses to SCE, which in turn, seeks to pass those to its ratepayers. DRA opposes SCE's attempt to charge its ratepayers for some of those fees and expenses.[1350]

DRA recommends, for example, disallowance of various forms of compensation for SCE's Board. In Rebuttal, SCE says that "an independent compensation study provides

---

[1342] SoCal Edison Company (1980) 5 CPUC 2d 39; D.92549; 1980 Cal. PUC Lexis 1296*48.

[1343] In Re Southern Californian Edison Company (1996) D. 96-01-011, 1996 Cal. PUC Lexis 23.

[1344] Ex. SCE-22, Vol. 2, p. 10.

[1345] Ex. DRA-12C-R, p. 29.

[1346] Ex. DRA-12-C-R, p. 29 citing confidential response to DRA-SCE-004-DFB, Q/A 22. DRA agrees that the litigation costs DRA included in Ex. DRA-12-C-R should be reduced to reflect SCE's 56% ownership share of the Mohave Generating Station. (23 RT 3879, Bower/ SCE.)

[1347] Ex. SCE-7, Vol. 2, p. 25.

[1348] Ex. SCE-22, Vol. 2, p. 13.

[1349] Ex. DRA-12-R, p. 31.

[1350] Ex. DRA-12-C-R, p. 30.

evidence that the Board's total compensation is reasonable" and that, therefore, "…ratepayers should be indifferent as to its components."[1351] DRA disagrees. Neither the compensation components, nor the allocation to ratepayers is per se reasonable merely because SCE paid for a study that says so.

DRA also recommends that "Director Education and Recruitment Costs" be excluded from recorded costs. It is not at all clear what these costs are for or what they have been spent on in the past. In Rebuttal, SCE gives as "examples of training" such things as "utility finance courses" and "nuclear safety training." If EIX is recruiting members for its Board who are so unfamiliar with utility operations that they need training in utility finance and nuclear safety, then this seems all the more reason that SCE's utility ratepayers should not be responsible for either the directors' compensation or the training costs.

DRA recommends the Commission adopt a 2012 forecast of $2.497 million for Corporate Governance Account 930.

9.3.4. Capital Project: Electronic Discovery

SCE's Law Department forecast includes a cost of $4.882 million for a capital project for Electronic Discovery for 2010-2012.[1352] DRA recommends no ratepayer funding for this capital project.[1353] SCE costs were "based on a vendor estimate"[1354] which, in turn, seems to be based on only the vaguest information provided by SCE to the vendor.[1355] DRA still considers that SCE has provided insufficient justification for this capital project and cost estimates, and continues to recommend no ratepayer funding for it in this GRC.

[1351] Ex. SCE-22, Vol. 2, p. 14.

[1352] See Ex. SCE-7, Vol. 2, Chapter II, page 32.

[1353] Ex. DRA-12-R, p. 31.

[1354] Ibid.

[1355] Ex. SCE-22, Vol. 2, p. 23, lines 1-3: "The cost estimates provided by vendors in the RFI process were based on each vendor's standard cost of software sales, which includes the costs of the product and implementation. It was necessary for vendors to use standard costs because, as mentioned above, SCE had not provided all of the details of the project."

9.4. Claims

SCE's Claims Division is forecasting $50.289 million for the Test Year 2012.[1356] This represents an increase of 18% over 2009 Adjusted Recorded costs of $42.552 million. DRA's Test Year 2012 forecast is $41.696 million.[1357]

9.4.1. Account 925: Injuries and Damages – Claims

As discussed in more detail below in Section 25 relating to DRA's Audit, DRA recommends that all costs associated with the Happy Camp fire be removed for purposes of forecasting SCE's Test Year expenses.[1358]

9.4.2. Account 925: Injuries and Damages – Claims Reserve

SCE says its 2009 recorded adjusted Claims Reserves amount was $34,882. SCE is forecasting $42,550 for the Test Year.[1359]

DRA recommends that the 2009 recorded amount of $34.882 million be used to forecast claims reserve amounts for the Test Year subject to additional reserve reductions relating to the Happy Camp Fire and the Navajo Nation Royalty Litigation, which are discussed in more detail in Section 25 of this Brief.

In Rebuttal, SCE says it is "unrealistic for DRA to ignore SCE's higher liability exposure when forecasting claims related to new wildfire insurance."[1360] SCE argues that its potential liability exposure for wildfires has increased significantly and that, "in light of its new insurance structure," SCE has concluded that the "only way to provide an objective forecast that accounts for SCE's new liability exposure was to provide a 'backcast' or a synthesis of historical records of large fire incidents with the new insurance coverage."[1361] SCE's proposal is flawed on numerous levels.

First, there is SCE's choice of a "backcast" method to forecast. Considering how much of its Rebuttal testimony SCE devotes to criticizing other parties for failing to follow "forecasting" principles from a 1989 decision, SCE's suggestion here that its backcast is the

---

[1356] Ex. SCE-7, Vol. 2, p. 34.

[1357] Ex. DRA-12-R, p. 31.

[1358] Ex. DRA-22-C, p. 16.

[1359] Ex. SCE-22, Vol. 2, p. 27.

[1360] Ex. SCE-22, Vol. 2, p. 28, lines 11-13.

[1361] Ex. SCE-22, Vol. 2, p. 28.

"only objective" method is, to say the least, surprising. Although SCE's witness sponsoring this testimony says that a backcast estimate is "somewhat" one of the methods of forecasting described in D.89-12-057, DRA has been unable to find any such reference.[1362]

Second, SCE's chosen method allows SCE to increase the costs it actually did pay in 2007 by a significant amount as if the "new insurance coverage" were in effect then, and use that "backcast" to inflate its 2012 forecast.[1363] The year 2007 was an extraordinary year for large wildfires.[1364] The year 2007 was also the year of the Malibu Canyon fire which burned over 4,000 acres.[1365] In fact, SCE itself is the subject of a Commission investigation into the Malibu Canyon fire to determine whether SCE's violations of General Orders or Public Utilities Code sections may have caused that fire. SCE neglects to mention that investigation anywhere in its testimony, though its wildfire insurance witness was interviewed by Commission investigators in connection with that wildfire.[1366]

Finally, SCE's own conduct with regard to obtaining insurance does not suggest any sense of urgency. After submitting this testimony in November 2010 describing SCE's increased financial liability resulting from the new insurance structure, it seems SCE has done very little about it. As of the date SCE submitted its Rebuttal testimony, July 5, 2011, SCE had not yet purchased supplemental wildfire insurance.[1367]

DRA continues to recommend that the Commission adopt SCE's 2009 recorded amount of $34.882 million to forecast claims reserve amounts for TY 012 subject to additional reserve reductions for the above-mentioned litigation matters.[1368]

9.5. Workers' Compensation

SCE's Workers' Compensation is forecasting $22.282 million for Test Year 2012. This represents an overall increase of 9.27% over 2009 recorded adjusted expenses of $20.932 million. DRA's forecast is $20.06 million.

[1362] 16 RT 2382, Ramos/ SCE.

[1363] Ex. DRA-12-C-R, p. 33.

[1364] See Ex. SCE-22, Vol. 2, p. 28 citing Ex. DRA-22C, p. 33.

[1365] 16 RT 2379, Ramos/ SCE.

[1366] Id.

[1367] Ex. SCE-22, Vol. 3, p. 52.

[1368] Ex. SCE-22, p. 28, lines 6-9, referring to Ex. DRA-12-C-R and Ex. DRA 22-C.

9.5.1. Workers Compensation Account 925 Staff

SCE forecasts labor costs for its Workers' Compensation Division in the amount of $4.128 million in Test Year 2012, an increase of $578,000 over 2009 labor costs of $3.55 million. SCE says the $578,000 increase is to hire eight additional employees for the Test Year 2012.[1369] DRA recommends removing $578,000 from Test Year 2012 forecast. SCE has not provided sufficient quantitative justification for the increase in labor costs.

In Rebuttal, SCE says it has shown the need for more claims representatives and administrative assistants. According to SCE, in order to comply with all state and federal statutes and rules, claims representatives are not able to administer caseloads as large as they had five years ago and SCE has had to reassign some tasks to outside counsel that could have been handled by the claims staff had their caseloads been lower.[1370] Although the implication is that SCE's Outside Counsel costs will be reduced if the Commission authorizes additional funding for claims representatives, in fact SCE did not include a corresponding decrease in Outside Counsel costs.[1371] DRA, therefore, continues to recommend that the additional $578,000 be removed from the Workers' Compensation forecast.

SCE says it used a budget-based method to forecast its $4.128 million in Workers' Compensation labor costs for the Test Year. DRA disagrees with this method of forecasting as speculative and unreliable. DRA recommends that the forecast for Test Year 2012 be based on a five year average. Using a five year average takes into consideration the variance in labor costs over the record period. DRA's 2012 forecasts is $3.258 million for labor costs.

9.5.2. Workers Compensation Account 925 Reserves

SCE forecasts $15.099 million for Test Year 2012 for Workers' Compensation Reserves. This represents an overall 9.8% increase over 2009 recorded adjusted expenses of $13.747 million. DRA recommends using 2009 Adjusted Recorded $13.747 million for the Test Year 2012. The 2009 record figure represents a reasonable forecast for the test year because Workers' Compensation (non-labor) costs have declined substantially due to changes in the law.[1372]

[1369] Ex. SCE-7, Vol. 2, Table IV-9, p. 55.

[1370] Ex. SCE-22, Vol. 2, p. 33.

[1371] 16 RT 2288, Jennerson/ SCE.

[1372] See Ex. DRA-12-C-R p. 36 for SCE's Workers Compensation Reserves liability as of the end of the

9.6. Ethics and Compliance

SCE forecasts $3.1 million for its Ethics and Compliance Department for Test Year 2012. This represents an overall increase of 35.4% over 2009 recorded adjusted expenses of $2.301 million. DRA's forecast for TY 2012 is $2.137 million.

In SCE's last GRC, DRA recommended zero ratepayer funding for SCE's Ethics and Compliance Department on the grounds that SCE has been a regulated utility for years and as such, should have been practicing good business ethics all along. DRA also noted that, in the TY 2009 GRC, the record was replete with evidence of SCE's ethics and compliance problems. The Commission rejected DRA's argument in its decision on SCE's TY 2009 and approved SCE's request for $2.122 million in the 2009 Test Year.[1373]

In this GRC, DRA has recommended a two-year average to forecast for the Test Year 2012. In light of the record, DRA's proposal may have been overly generous.

First, it appears that SCE's Ethics and Compliance Department functions largely, if not solely, for the benefit of SCE's shareholders. The examples SCE gives for its "compliance" functions seem directed primarily to protecting SCE, the corporation, and SCE's shareholders. In its reference to the Ethics and Compliance Management Program, SCE says it satisfies all of the requirements of the Sarbanes-Oxley Act.[1374] The purpose of the Sarbanes-Oxley Act, as set out in the Act itself, is to "…[p]rotect investors by improving the accuracy and reliability of corporate disclosures made pursuant to public law and for other purposes."[1375] Similarly, compliance with Energy Regulation, which covers CPUC, FERC, and California Energy Commission (CEC) matters, with Environmental Health and Safety, which covers federal and state Environmental Protection Agency and Occupational Safety and Health Administration matters, and with Employment, which covers U.S. Department of Labor, National Labor Relations Board, and Equal Employment Opportunity Commission matters, all protect SCE and

---

year 2010.

[1373] D.09-03-025, mimeo, p. 159.

[1374] Ex. SCE-22, Vol. 2, p. 62.

[1375] Pub.L.107-204 116 Stat 745, enacted July 30, 2002: "An Act – To protect investors by improving the accuracy and reliability of corporate disclosures made pursuant to Securities Laws and for other purposes."

its shareholders from potential lawsuits and fines and penalties.[1376] Yet, it seems SCE is asking only its *ratepayers* to fund the costs of the Ethics and Compliance Department.[1377]

The other reason DRA questions whether SCE ratepayers should be required to pay any costs for SCE's Ethics and Compliance Department is SCE's track record. SCE's history of unethical behavior apparently stretches back almost 15 years starting with a long-running fraud that involved SCE's Performance Based Ratemaking measures.[1378] While SCE attempted to downplay management responsibility in that case,[1379] and at the same time take credit for "reporti[ing] the results of its [internal investigation] to the Commission,"[1380] the Commission investigation and findings tell a very different story.

The Commission decision that concluded the investigation found, among other things:

> For seven years, some [SCE]management actively encouraged employees to manipulate survey data, and senior management, who knew or should have know that the data was suspect, filed for, and received, PBR awards.[1381]

And:

> For seven years during which time SCE collected or requested PBR health and safety awards, SCE's own internal auditors knew of problems with both first aid reporting and OSHA recordable reporting.[1382]

SCE was ultimately found to have violated Rule 1.1 of the Commission's Rules of Practice and Procedure, Public Utilities Code Sections 451, 581 and 702, and

---

[1376] Ex. SCE-22, Vol. 2, p. 61.

[1377] 16 RT 2432, Mines/ SCE: Q: "What portion of the total cost of SCE's ethics and compliance department is SCE asking that ratepayers fund? A: The total cost, although there are some affiliate credits that are handled because we do support EMG as well."

[1378] 16 RT 2459, Mines/SCE.

[1379] D.08-09-038, mimeo, p. 36: "As we have said, the most important issue in this investigation is whether SCE management had direct knowledge of manipulation or falsification of customer contact data. SCE, in brief, presents the issue thusly: 'CPSD first alleges that SCE management had actual knowledge of falsification because one planner accused Shull and five planners accused Fine of providing vague direction to select the customers who would provide the highest survey score. These accusations against Shull and Fine have never been corroborated.... Accordingly, the fact that these vague and uncorroborated accusations were made by a handful of individuals – out of literally hundreds that were interviewed – cannot suffice to impute knowledge on SCE management that this practice was actually occurring.'"

[1380] 16 RT 2458, Mines/ SCE.

[1381] D.08-09-038, Finding of Fact 20.

[1382] D.08-09-038, Finding of Fact 41.

Decision 96-09-092 during the period 1997 – 2003. SCE was ordered to refund more than $80 million in Results Sharing revenue requirement and PBR Rewards, forego $35 million in Rewards it had requested but which had not yet been paid, and fined another $30 million.[1383]

Nor have SCE's ethical abuses stopped there. In 2008, the Nuclear Regulatory Commission issued an Order Substantiating Incidence of Willful Violations at SONGS by SCE. These were violations that had gone on over a period of five years and involved reports SCE made that fire watches were conducted when, in fact, they were not.[1384] In the TY 2009 GRC, SCE blamed these violations on "one employee" who "shirked her job."

In 2010, this Commission reached a decision resolving a Petition for Modification that SCE's Law Department had filed relating to certain costs at the Four Corners Generation Station. According to D.10-10-016, the filing SCE made included such serious errors and omissions that at least one Commissioner thought they rose to the level of Rule 1.1 ethical violations.

By a 4-1 vote, the Commission decided not to open a formal investigation into whether SCE's petition reached the level of a Rule 1 violation. The Commission did, however, order SCE's Law Department to undergo "Ethics Training." Then, in this GRC, SCE initially included a request to have ratepayers to pay for that training.[1385]

In any event, one Commissioner who reviewed SCE's filings in the Four Corners proceeding filed a dissent which included the following:

> I cannot agree with the decision that there is no need for consideration of potential sanctions against SCE for filing to comply with the Commission's rules simply because the correct facts ultimately came to light and SCE belatedly admitted that it had providing misleading information to the Commission.[1386]

When asked about the case, SCE's Vice President and Chief Ethics and Compliance Officer said she disagreed with that dissent and offered the following:

> Q: Is it your understanding that SCE did not provide misleading information to the Commission?

[1383] D.08-09-038, mimeo, p. 140, Conclusions of Law 1 -8, p. 141, Ordering Paragraphs 1-3.

[1384] 16 RT 2438, Mines/ SCE.

[1385] See Ex. DRA-12-C-R, p. 28.

[1386] Decision Granting in Part Petition of SCE to Modify D.07-01-039 (2010) D.10-10-016, Dissent of Commissioner Bohn.

> A: No. Again, this is not – I did not file that testimony. My understanding is that SCE provided the information it thought was relevant at the time. And from what you've read, the Commission disagreed with that. But that's the extent of my knowledge.[1387]

While the loyalty of SCE's witness to SCE is admirable, if this is an example of what SCE's ratepayers are getting for financing SCE's Ethics and Compliance Department, there seems to be a decided conflict of interest.

Meanwhile, as this GRC proceeds, the Commission is engaged in yet another investigation into SCE's conduct. This time it involves the 2007 Malibu Canyon fire. The purpose of the investigation is to determine whether SCE's conduct violated Commission orders or Public Utilities Code provisions and whether those violations, if any, were a cause of the fire. As the investigation has progressed, it is DRA's understanding that the Commission's Consumer Protection and Safety Division has alleged Rule 1.1 violations against SCE for, among other things, abuse of the discovery process and spoliation of evidence.[1388]

So, although SCE's management may have the opinion that, "since 2005, SCE has had a strong culture of ethical compliance,"[1389] the facts suggest otherwise.

For all these reasons, DRA now questions whether *any* ratepayer funding should be ordered for SCE's Ethics and Compliance Department. If, however, the Commission is going to order ratepayer funding for this Department, then DRA suggests it be at levels no higher than those DRA proposed in its testimony. These are described below.

9.6.1. Ethics and Compliance Account 920/921

SCE forecasts $1.909 million in labor costs for its Ethics and Compliance Department in Test Year 2012. This represents an on overall increase of 61% over 2009 recorded adjusted costs of $1.186 million. In its testimony, DRA recommends the Commission adopt SCE's 2009 recorded adjusted expenses of $1.186 million for labor costs in the Test Year.[1390]

[1387] 16 RT 2446, Mines/ SCE.

[1388] Investigation into the Operations and Practices of SCE et al. Regarding the Utility Facilities and the Canyon Fire in Malibu of October 2007 I.09-01-018, Motion of the Consumer Protection and Safety Division for a Continuance of Schedule and Attachment 1, Declaration of Edward Moldavsky (with Accompanying Exhibits E- -- E-14), and Attachment 2, Declaration of Harvey Y. Morris (With Accompanying Exhibits H-1 -- H-6, pp. 5, 13.)

[1389] 16 RT 2438, Mines/ SCE.

[1390] Ex. DRA-12-R, p. 37.

SCE says its proposed increase in labor costs for the 2010 through 2012 period reflects the increase in staffing needed to provide greater compliance management oversight.[1391] SCE says the increase of $723,000 is to fill two vacancies and add five additional positions. Ethics & Compliance has not provided sufficient quantitative justification for the increase in labor costs. DRA recommends removing $723,000 in labor costs from Test Year 2012 forecast. In its testimony, DRA's forecast is $1.186 million for labor costs.

SCE's forecast for Ethics & Compliance non-labor costs for Test Year 2012 uses recorded 2009 data as its base and adds $93,000.

Non-labor costs are related to the amount of labor costs. Consistent with DRA's recommended disallowance of increased labor costs, DRA recommends no more than $346,000 for the Test Year.

If the Commission is inclined to order any ratepayer funding, DRA recommends the Commission adopt SCE's 2009 recorded labor and non-labor costs for TY 2012.

9.6.2. Ethics and Compliance Account 923

SCE forecasts $772,000 in Outside Services costs for its Ethics and Compliance Department in Test Year 2012. In its testimony, DRA recommends the Commission use a two year average to forecast for Test Year 2012. SCE's Ethics and Compliance Department was established in late 2005. A two year average (2008-2009) is more likely to be representative of the costs for Ethics and Compliance's Outside Services.

If the Commission is inclined to order any ratepayer funding of SCE's Ethics and Compliance Department costs for Outside Services, it should be for no more than $605,000.[1392]

9.7. Regulatory Policy and Affairs

SCE is requesting a total of $15.446 million in A&G expenses for its Regulatory Policy and Affairs Department in the Test Year. DRA recommends $12.223 million in the Test Year.[1393]

[1391] Ex. SCE-7, Vol. 2, p. 59.

[1392] Ex. DRA-12-R, p. 38.

[1393] Ex. DRA-12-R, p. 39.

9.7.1. RP&A – Labor Expenses

RP&A is forecasting an increase of $1,089,408 to fill three vacancies and $1,319,928 for 13 additional positions.[1394] RP&A states:

> "With the on-going workload in regulatory activities, coupled with the growth in RP&A's regulatory compliance activities described below, RP&A plans to accomplish the required work with 125 employees in 2012, as increase of 126 employees over RP&A's recorded 2009 level."[1395]

RP&A does not keep records tracking the activity of its employees' workload.[1396] Without a quantifiable means of determining workloads and number of employees to accomplish those workloads, there is no justification for the 16 additional employees in the Test Year 2012. In fact, during record period, RP&A's FTEs ranged from 96 in 2005 to 109 in 2009,[1397] which averages to approximately 99.6 FTEs per year. RP&A has been able to accomplish its workload with approximately 100 employees during the past five years, it seems appropriate to continue to have 100 employees in RP&A. DRA recommends that $2.409 million be removed from the Test Year 2012 labor forecast. DRA's 2012 forecast is $9.588 million.

9.7.1.1. Affiliate Transaction Rules Compliance

SCE's RP&A's Regulatory Compliance section is primarily responsible for ensuring compliance with the Commission's Affiliate Transaction Rules (ATR). SCE's RP&A is seeking to include $450,000 for ATR costs in its Test Year 2012 forecast. SCE's RP&A contends that by ensuring compliance with the Affiliate Transaction Rules the ratepayers are benefited.

In its decision for SCE's 2006 GRC, the Commission considered this issue:

> "TURN states that the Commission has held that the costs for complying with affiliate transaction rules should not be charged to ratepayers, since there is no basis to conclude 'ratepayers are in any other way the primary beneficiaries of [the utility's] decisions to diversify into non-regulated activities.' TURN further states that SCE has made no showing in this case to disapprove the Commission's conclusions regarding the need for benefits of affiliate compliance activities. TURN suggests that SCE can allocate the costs to affiliates or shareholders.

[1394] Ex. DRA-12-R, citing Response to DRA-SCE-020-DFB, Question 3.

[1395] Ex. SCE-7, Vol. 3, p. 5.

[1396] Ex. DRA-12-R, citing Response to DRA-SCE-022-DFB, Question 1a.

[1397] Id.

> TURN's proposed adjustment is consistent with Commission precedent, is not disputed by SCE, and will be adopted."[1398]

In its decision on the Pacific Gas and Electric Company's (PG&E) Test Year 1999 GRC, the Commission stated:

> "PG&E has not demonstrated that utility ratepayers benefit from the profits earned by affiliates, or that ratepayers are in any other way the primary beneficiaries of its decisions to diversify into non-regulated activities. PG&E's establishment of a holding company which oversees affiliates that engage in non-regulated activities was largely, if not entirely, the consequence of management decisions that benefit shareholders. As TURN states, if PG&E had no affiliates, it would have no need of an affiliate compliance department. Moreover, ratepayers would have no exposure to the risks of non-regulated activities to be protected against in the first instance. Accordingly, the costs of affiliate rules compliance properly belong with the utility's affiliates. We therefore, adopt ORA's recommendation to allocate compliance costs to the affiliates."[1399]

SCE's rationale in its Direct testimony for changing this long-standing Commission policy is buried in a footnote which states:

> The Affiliate Rules include the CPUC ATRs and SCE's Holding Company Conditions and the FERC Standards of Conduct and Affiliate Restrictions. In SCE's previous two GRC proceedings, intervenors have argued for exclusion of CPUC ATR compliance costs, and the CPUC has agreed. SCE believes that the costs of compliance with the CPUC ATRs are appropriately recoverable from ratepayers and has included them in RP&A's 2012 Test Year expenses.[1400]

In Rebuttal, SCE repeats this argument, albeit at greater length, citing to a 1979 decision, and a 2004 decision from this Commission and one from Arizona.

The Commission's policy has been to not allow ATR costs to be funded by ratepayers, the same reasoning applies here; D. 09-03-025 states:

> "SCE estimates $0.285 million (constant 2006%) in 2009 TY O&M expenses for compliance with the Affiliate Transaction Rules by the Regulatory Policy & Affairs department. DRA recommends this amount be removed from the forecast,

---

[1398] D.06-05-016, mimeo page 153.

[1399] D.00-02-046, mimeo, page 273.

[1400] Ex. SCE-7, Vol. 3, p. 13, Footnote 19.

> nothing that the Commission excluded these amounts from revenue requirement in the 2006 GRC. In response, SCE contends that, for approximately two decades, the Commission permitted SCE to recover these costs in rates and the Commission's reversal of policy on this matter in the 2006 GRC was not well-founded. SCE asserts that ratepayers have an interest in SCE maintaining Affiliate Transaction Rule compliance.
>
> We affirm the policy set forth in the 2006 GRC, and remove these compliance costs from the forecast. These compliance costs are incurred to support the operations of SCE's affiliates and, as such, requiring ratepayers to bear those costs would amount to a subsidy of those operations by ratepayers. We disagree with SCE's argument that ratepayers should pay because SCE's compliance with these rules protects ratepayers."[1401]

Nothing in SCE's testimony justifies changing Commission policy regarding ATR. DRA recommends that $450,000[1402] in labor costs be removed from the Test Year 2012 forecast.

9.7.2. R&A Labor Forecast

RP&A forecast its labor costs for the Test Year 2012 using a budget-based, method to arrive to at its forecast of $12.812 million.[1403] DRA disagrees with this methodology in that labor costs in this area have not been stable for the past five years. The labor costs have fluctuated from $9.894 million in 2005 to $10.403 million in 2009. When costs have significant fluctuations from year to year, it is more appropriate to use an averaging methodology.

In Rebuttal, SCE says that, "[l]ike the majority of its testimony on SCE's other A&G areas, DRA's testimony on the Test Year forecast of labor expenses for SCE's RP&A Department misapplies the forecasting guidance provided in Decision (D).89-12-057."[1404] SCE certainly has every right to use whatever forecasting method it thinks reasonable, but the 1989 decision is not exactly the most recent Commission expression of guidance on forecasting.

For example, as discussed above in more detail in Section 2.6 of this Brief, the Commission's decision in SCE's Test Year 2006 GRC concluded that there are a number of

---

[1401] See D.09-03-025, mimeo page 162.

[1402] See SCE-7, Vol. 3, Chapter I, Table I-1, page 7.

[1403] See Workpapers for Exhibit SCE-07, Volume 3, Chapter I, page 3.

[1404] Ex. SCE-22, Vol. 3, p. 2.

acceptable methodologies for forecasting test year costs, and that, in some cases, two or more methods may be equally appropriate. [1405] :

In SCE's last GRC, SCE asked for an increase in expenses for its regulatory policy and affairs department saying it needed the increases due to "increased labor costs resulting from a substantial and continuing increase in regulatory workload." The Commission declined to give SCE that increase, saying that SCE's "[r]ecorded labor costs have been relatively stable during 2002 to 2008. As such, SCE has failed to adequately support its request of $1.471 million for its test year 2009 labor forecast In this instance we find it reasonable to rely on a five-year average of the recorded data for both labor and non-labor."[1406]

DRA's recommendation that the Commission use a five-year average of SCE's RP&A labor costs for this GRC is consistent with the guidance offered by the Commission's most recent decisions in SCE GRCs.

SCE's recorded RP&A labor costs included Spot Bonuses, ACE awards, and ATR costs, $453,000, $62,000, and $1,427,000, respectively. Prior to applying a five year average, DRA removed these labors costs so that they are not funded by ratepayers.[1407] DRA has forecasted labor costs in RP&A using the five year average. This results in a further reduction to the RP&A's labor costs of $815,000 for the Test Year 2012. DRA's 2012 forecast is $9.588 million for labor costs. DRA recommends a total of $3.224 million be removed from the Test Year 2012 forecast for labor.

9.8. NERC/CIP-Related Costs

In its Rebuttal, SCE criticizes DRA's recommendation that SCE's RP&A labor forecast continue at 100 employees. SCE refers to the "... expanded responsibilities of RP&A's Regulatory Compliance organization that began in 2009 ... in response to the Federal Energy Regulatory Commission's (FERC's) policy directions related to its expectations on effective compliance programs and SCE's Compliance Management Program." SCE specifically references Regulatory Compliance's new responsibilities associated with providing company-

[1405] D.06-05-016, mimeo, pp. 10 – 11.

[1406] D.09-03-025, p. 160Ex.

[1407] DRA's reason for removing Spot Bonuses and ACE Awards is described in more detail in Section 8.4 of this Brief.

wide governance of SCE's compliance with the North American Electric Corporation (NERC) Reliability Standards (including Critical Infrastructure Protection (CIP) standards."[1408]

As discussed above in Section 5.18 of this Brief, SCE has not explained why these NERC/CIP costs, which are FERC jurisdictional, are being included in SCE's GRC request.

DRA continues to recommend that $2.409 million be removed from SCE's TY 2012 RP&A labor cost.

9.9. Corporate Membership Dues and Fees

DRA has no comments on this issue at this time.

9.10. Corporate Communications

SCE is forecasting $16.854 million for Test Year 2012.[1409] This is an overall increase of 31.9% over 2009 Adjusted Recorded costs of $12.781 million. DRA's 2012 forecast is $12.802 million.

9.10.1. Corporate Communications Account 920

Corporate Communications is forecasting $9.852 million in labor costs for Test Year 2012, an increase of $2,906,000,[1410] over 2009 levels. DRA's recommendation is $6.827 million.

Of the increase SCE seeks, SCE says $1,158,800 is to fill nine vacancies and $1,747,200 is for 19 additional positions. SCE provides insufficient support for filling nine vacancies and adding 19 new positions in the Test Year 2012. Therefore, DRA has removed the $2,906,000 in labor costs from the Test Year 2012 forecast. In addition, DRA has adjusted out $40,000 for a one-time media event, Spot Bonuses of $444,000 and ACE awards of $454,000 during the record period 2005-2009. DRA's 2012 forecast removes $3.025 million from SCE's Test Year 2012 forecast.

9.10.2. Corporate Communications Account 921

Corporate Communications is forecasting $4.856 million in non-labor costs for Test Year 2012, an increase of $452,000 over 2009 levels. DRA's forecast is $4.295 million.

[1408] Ex. SCE-22, Vol. 3, pp. 7- 8.

[1409] Ex. SCE-7, Vol. 3, p. 26.

[1410] Ex. SCE-7, Vol. 3, p. 37.

SCE says its "Community Partnerships helps employees with common interests and cultural backgrounds join together to accomplish diverse community improvements and cultural projects. Called 'affinity groups' these teams are formed by employee volunteers. The groups are supported by the Company through a yearly stipend that the groups use to support their cultural activities."[1411]

Ratepayers should not be forced to contribute to SCE's cultural activities. These are all activities that help SCE promote itself or gain goodwill in its community. If SCE wants to continue these activities, it can do so at its shareholders expense. Insofar as SCE's non-labor forecast is linked to its labor forecast, and DRA recommends removing forecasted labor costs of $2.906 million, the non-labor forecast should also be reduced. DRA recommends that $561,000 be removed from Test Year 2012.[1412]

9.11. Property and Liability Insurance

SCE is forecasting $67.98 million for Property and Liability Insurance for the Test Year 2011. This represents an overall 188% increase of $44.363 million over 2009 Adjusted Recorded costs of $23.617 million.[1413] DRA's 2012 forecast is $58.31 million.

For Property Insurance, SCE forecasts $15.417 million for the Test Year. DRA's 2012 forecast is $15.108 million.

SCE purchases (1) non-nuclear Property Insurance coverage for its transmission and distribution assets, power plants, and general facilities; (2) blanket crime insurance for losses due to theft, robbery, and computer and wire fraud; and (3) nuclear property insurance. Property insurance expense increased from $6.933 million in 2005 to $10.409 million in 2009. This increase is due primarily to the decrease in nuclear property insurance distributions. SCE used a budget based, methodology for forecasting Property Insurance for the Test Year 2012.

SCE's 2010 recorded Property Insurance costs were $15.108 million.[1414] DRA recommends that the 2010 recorded costs should be the basis for forecasting for the Test Year 2012. DRA recommends that $309,000 be removed from SCE's Test Year forecast.

[1411] Ex. SCE-7, Vol. 2, pp. 33-34.

[1412] Ex. DRA-12-R, p. 45.

[1413] Ex. SCE-7, Vol. 3, p. 51.

[1414] Ex. DRA-12-R, p. 48 citing Response to DRA-SCE-162-DFB, Q. 3 Attachment.

For Liability Insurance, SCE is forecasting Liability Insurance for Test Year 2012 to be $52.563 million. This is an increase of 298% over 2009 adjusted recorded.[1415] DRA's 2012 forecast is $28.366 million.

SCE maintains several types of Liability Insurance such as General Liability, Fiduciary Liability, Directors and Officers Liability, Workers Compensation, Miscellaneous Liability Insurance and Surety Bonds, and Nuclear Insurance. SCE has properly excluded 50% of the Directors and Officers Insurance, which is in compliance with past Commission decisions and directives. However, SCE used a budget based methodology for forecasting Liability Insurance for the Test Year 2012. DRA disagrees with SCE's forecasting method believing that it is likely overstated. For example, SCE implies in its Direct and Rebuttal testimony that there is some urgent necessity for it to obtain supplemental wildfire liability insurance, yet, as of the evidentiary hearings, SCE still had not purchased it. In fact, it sounds from the testimony of SCE's insurance broker, that it is SCE's intent to purchase supplemental wildfire liability insurance only if ratepayers pay for it.[1416] Given SCE's own conduct in postponing the purchase of this insurance, DRA opposes SCE's attempt to charge ratepayers for it.

SCE's 2010 recorded Liability Insurance costs were $28.366 million.[1417] DRA recommends that the 2010 recorded costs should be the basis for forecasting for the Test Year 2012. DRA recommends that $24.197 million be removed from SCE's Test Year forecast.

10. Power Procurement

SCE's Power Procurement and Business Unit (PPBU) submitted SCE's testimony on procurement. PPBU forecast expenses by Department; DRA analyzed PBBU's forecasts by Department and Division as well. The total forecast estimates for PPBU Administrative and General (A&G) expenses (excluding Account 926/Pension and Benefits) for Test Year 2012 was $59,340,000, and $73,350,000 for capital from 2010 through 2012. DRA reduced the A&G expenses by $7,222,000, recommending that SCE be authorized $52,118,000 in A&G expenses for Test Year 2012. For PPBU capital, DRA recommends $49,250,000.[1418]

[1415] Ex. SCE-7, Vol. 3, p. 65.

[1416] 19 RT 3145-3146, Kempsey/ SCE.

[1417] Ex. DRA-12-R, p. 48.

[1418] Ex. DRA-14, p. 1.

Most of PPBU's forecast expenses are for new positions which SCE claims are necessary to address many regulatory and legislative initiatives that will impact the group significantly over the GRC period. These initiatives include: 1) Increase in renewable and Combined Heat and Power Procurement (CHP) procurement activities, 2) Changes in Electricity Markets such as the California Independent System Operator (CAISO) Market Redesign and Technology Upgrade (MRTU) enhancement, 3) Environmental issues (AB32) such as greenhouse gas and once-through-cooling, and 4) Integrated resource planning. However, on closer examination, it is clear that all but one of these initiatives are old and rather than increasing, most of the activities on these initiatives are decreasing because the issues have been substantially addressed and the complexities reduced over time.

Additionally, under the CAISO initiative, which forms the basis of many of SCE's requested increase in revenue, the driver for the increases are NERC/CIP costs which SCE is supposed to collect from Transmission Access Charges (TAC) at the FERC not from the State. This deliberate inclusion of this FERC cost as a driver for SCE's procurement request even further overstates SCE's forecast.

10.1. Market Strategy and Resource Planning Department

DRA recommends $3,964,000 for the Market Strategy and Resource Planning Department (MS&RP) A&G expenses for Test Year 2012. This is $1,421,000 less than SCE's estimate of $5,385,000.

MS&RP performs market monitoring, market design, and long-term resource planning functions, as well as internal consulting to SCE business units on strategic projects. SCE's forecast of $5,383,000 for this group is 40 percent higher than recorded 2009 expenses and approximately $1,499,000 of these expenses is related to labor costs. These costs were calculated using 2009 Market Reference Point (MRP) for each job title[1419]. DRA's Table 14-4 in Exhibit DRA-14 replicates and summarizes the annual salaries and total labor increase from Exhibit SCE-8, Table II-1.

[1419] Ex. SCE-08, p.36.

Table 14-4
Southern California Edison
Market Strategy & Resource Planning
Exhibit SCE-08, Table II-1

MS&RP Incremental Staffing	# of Positions	Annual Salary	Total Labor Increase
Analyst-Financial 1	1	$60,300	$60,300
Analyst-Financial 2	2	$75,600	$151,200
Analyst-Financial 3	2	$92,700	$185,400
Manager-2	1	$128,700	$128,700
Mgr-Project/Product 1	6	$100,200	$601,200
Mgr-Project/Product 2	3	$123,900	$371,700
	15		**$1,498,500**

SCE's assignment of these incremental positions among MS&RP's various divisions and DRA's recommended number for each division are as follows: (1) Resource Planning – 3 New Employees requested, 0 Recommended[1420]; (2) Market Design and Analysis Division – 5 New Employees requested, 0 Recommended[1421]; (3) Strategic Projects Group – 4 New Employees requested, 1 Recommended[1422]; (4) Resource Policy Economics Division – 3 New Employees requested, 1 Recommended[1423].

In all, DRA recommends adding only 2 new positions to MS&RP partly because there is substantial overlap in the stated descriptions of what the new employees would do. Indeed there is substantial overlap in the duties and responsibilities of the divisions in MS&RP. For instance, while the Resource Planning group populates, maintains and prepares forecast information needed in SCE's resource planning models used to support SCE's regulatory filings at state and federal levels[1424], Resource Policy and Economics (RP&E) division provides support in regulatory proceedings involving resource planning and electricity policy development

[1420] Ex. DRA-14, p.7.
[1421] Ex. DRA-14, p.14
[1422] Ex. DRA-14, p.16
[1423] Ex. DRA-14, p.19
[1424] Ex. SCE-08, p.24.

objectives. Stating one division's responsibilities generally and the other division's responsibilities specifically does not mask the fact that "support in regulatory proceedings involving resource planning and electricity policy developments", encompasses "populating, maintaining and preparing forecast information needed in State and federal regulatory filings".

The drivers for all these new positions are essentially the following regulatory proceedings: (1) The Long-Term Procurement Proceedings (LTPP) at the Public Utilities Commission (PUC); (2) the Integrated Energy Policy Report (IEPR) proceeding at the California Energy Commission (CEC); (3) future regulation of Green House Gas (GHG) or Assembly Bill (AB) 32, (4) efforts to eliminate Once Through Cooling (OTC) generation plants, (5) Renewable Portfolio Standard program (RPS), and (6) Market Redesign and Technology Update (MRTU) at CAISO and related proceedings at the FERC.

These drivers are also used to justify all the incremental positions in the PPBU, with some proceedings more prominent in the requests of some divisions than others. In MS&RP, for instance, the more prominent drivers are the LTPP and the IEPR. According to SCE, the Resource Planing and Economics group (RP&E) within MS&RP needs the three new positions "to support a rapid growth related to (LTPP and IEPR) regulatory activities".[1425] However, there is no rapid growth in LTPP and IEPR activities, which forecast California energy needs over a ten to fifteen year planning horizon and revisit them every two years.

The biennial LTPP and IEPR proceedings, on average, take two years each to complete, and both the PUC and the CEC have held these proceedings for almost a decade in the case of the LTPP and more than a decade in the case of the IEPR. Further, the subject matter and activities in the proceedings are repetitive from year to year, because they essentially forecast most of the same time period every year, adding only two years to replace the time that has passed since the last proceeding, while adjusting the existing data with new information acquired after the last proceeding was held. The scope of the work remains substantially the same from year to year as well, and the utilities often work together to derive California wide expectations on demand, supply, energy efficiency, distributed generation, renewable resources, reliability and demand response data, etc.

Q. The work you described with respect to demand forecasting in this proceeding are all things that SCE has always done with respect to

[1425] Ex. SCE-8, p.33.

> LTPP and renewables. I'm trying to understand how the work you anticipate from 2009 to 2012 changes from what you've always done.
>
> …
>
> ALJ DARLING: And I think to be responsive, what he's asking for is what's different between 2009 and 2012 from these types of activities that have been conducted before as part of the routine operations.
>
> THE WITNESS: Mm-hmm. Right.
> So let me just give you a couple of examples here.
>
> One of the things this division does is that we have a meteorologist that forecasts the weather, and they've primarily been focusing on weather forecasting in our service territory because the temperature drives the demand. We've been doing that for a number of years. And there are benefits to getting a better local forecast of the weather.[1426]

This testimony does not say that PPBU activites in the 2009 -2012 period are any different from the type of activities PPBU has always done. In fact, the testimony confirms the fact that there is nothing different, stating "[w]e've been doing this for a number of years."[1427]

Another example given by the same witness was as follows:

> So another area that we're looking to get into is now looking at the weather where the renewable resources are, where the solar plants are, where the wind plants are because clearly the solar radiance affects the output of the solar plants. Cloud cover decreases it. Clear sky increases it. More wind increases wind production. So to have a better handle on production, the meteorologist would expand their scope into forecsting outside the local area.[1428]

Again there is nothing new in the fact that "Cloud cover decreases [solar radiance], Clear sky increases it. [and] More wind increases wind production."[1429] SCE must have been doing this form of analysis from the inception of both the LTPP and the IEPR. Moreover, it should be noted that the CEC does the same investigations as well for purposes of comparing its findings with the utilities' findings.

[1426] 20 RT 3280:24 – 3281:22, Cini/ SCE.

[1427] 20 RT 3281:19 – 20, Cini/ SCE.

[1428] 20 RT 3281:23 – 3281:6, Cini/ SCE.

[1429] 20 RT 3282:1 – 3, Cini/ SCE.

10.2. Energy Supply and Management Department

DRA recommends $26,438,000 for the Energy Supply and Management Department (ES&M) for Test Year 2012. This is $3,128,000 less than SCE's estimate of $29,566,000. Of this estimate, forecast labor cost is $21,769,000[1430], non-labor expense forecast is $7,797,000 for Test Year 2012[1431]. Within the non-labor costs are employee-related expenses (e.g., travel, telephone use, supplies, salary for temporary employees, and training), consulting costs, and a California Air Resources Board (CARB) GHG Administrative Fee[1432].

DRA does not object to the CARB GHG fee estimate in the non-labor costs, but requests that the Commission adopt the actual CARB fee in the final decision. The evidence adduced in this proceeding is that the implementation of CARB's GHG regulations will be delayed for one year.

ES&M Labor Expense

SCE requests 26 new positions for ES&M's seven divisions and DRA recommends 3 new positions. ES&M is responsible for performing the scheduling coordinator function with the California Independent System Operator (CAISO) for SCE's supply, demand, and contract resources. ES&M's seven divisions are: (1) Energy Planning - , (2) Energy Contract & Trading, (3) Energy Operations, (4) Demand Forecasting, (5) Regulation & Compliance, (6) Gas Strategy, (7) Bidding Strategies & Asset Optimization and (8) Executive Assistant.

Energy Planning division primarily examines factors such as resource capacity, physical and contractual operating characteristics, electric and natural gas prices and load conditions and potential transmission constraints. This information is used for day to day dispatch decisions as well as to support regulatory programs such as the LTPP and to cost effectively manage California Department of Water Resources (CDWR) contracts. There is nothing in SCE's testimony that shows why this division needs 2 new positions or that the activities are on the rise. On the contrary, ES&M activities are usually on the wane during recessions as electricity consumption tends to be directly proportional to economic activity. SCE's only attempt to

---

[1430] Ex. SCE – 8, p.61

[1431] Ex. SCE – 8, p.62

[1432] Ex. SCE – 8, p.61

justify these positions is simply a description of the various duties of the positions within Energy Planning[1433].

Similarly, Energy Contracts and Trading division seeks two new positions to support expected "new challenges" during the next several years. What SCE refers to as "new challenges" are the integration of out of State intermittent resources, phase-out of Once Through Cooling, (OTC) expiration of CDWR contracts, potential increase in RA bilateral sales due to Direct Access reinstatement, and compliance with GHG regulations[1434]. SCE's claim that its list of Energy Contracts and Trading responsibilities constitutes "new challenges"' is not credible. All of these issues have either been resolved, are dormant, or have been fully addressed in prior proceedings. Primary responsibility for integration of renewable resources rests with CAISO, not SCE or any other utility. As SCE's head of ES&M testified, the output of most generators in the State "can be directly controlled by the grid operator to respond to system needs."[1435] The CEC outlined the plan for phasing out OTC generators as far back as 2005 identifying all the generators that have to be phased out and giving the utilities time to plan for such phasing out. In the 2006 LTPP, SCE assumed that those OTC plants would be retired and planned for new resources to replace them. Similarly, SCE has known of the expiration of CDWR contracts for almost a decade and has been purchasing replacement power.

> Q. Isn't it true that in the 2006 LTPP, Edison made assumptions regarding the expiration of this [CDWR] contract[s] and planned for it accordingly?
>
> A. Well, we've known about the expiration of these contracts for a long time. They were all signed almost 10 years ago. And so we have – I don't want to say we haven't been buying replacement power. We actually have been buying some.[1436]

Direct Access has been frozen until the last CDWR contract expires and it would require some action by the Commission to restart it. SCE's request for new resource to address DA is unfounded.

[1433] Ex. SCE – 8, pp. 40 – 42.

[1434] Ex. SCE – 8, p. 43

[1435] Ex. SCE – 23, p.14.

[1436] 20 RT 3287: 13 – 22, Cini/ SCE

ES&M's Energy Operations division requests two new employees in the Resource Planning group[1437], two new employees in the Renewable Resource Integration group[1438] and one new employee in the Systems/Project support group[1439]. SCE claims that these needs are "driven by the goal of having 33% of customers' energy needs derived from renewable resources."[1440] The Commission should deny SCE's request for new employees in the Energy Operations group because SCE does not need additional employees to integrate 33% renewables target. The Commission has authorized utilities to use tradable renewable energy certificates (T-RECs) to meet a substantial part of their RPS obligations. These T-RECs were approved in part to simplify RPS compliance, because they will not have to be integrated. Further, SCE offers no credible basis for its claim that, because there is a new 33% target, SCE needs five new employees to integrate those resources. Flexible compliance, contract failures and T-RECs all have to be determined before such a calculation can be made. In any case, any increase in employment resources to address integration should be at the CAISO not at the utilities.

It is important to note that SCE is using the new RPS target to justify new positions in both its renewable operations division of PPBU and its conventional resources operations division of PPBU, thus double billing ratepayers for essentially the same purpose.

Finally, it should be noted that ES&M division has 18 vacant positions that have been vacant for more than one year[1441]. Although SCE has not filled these positions, SCE is asking for 26 new positions it still cannot justify. The remaining divisions within ES&M fail to state any compelling reason for the new positions that SCE requests to add to them. In any case, the cumulative requests in those divisions do not exceed the currently vacant positions within ES&M. DRA's recommendation for three new positions may, in fact, be overly generous.

10.3. Renewable and Alternative Power Department

DRA recommends $5,106,000 for the Renewable and Alternative Power Department (RAP) for Test Year 2012. This is $1,559 less than SCE's estimate of $6,665,000. The RAP Department is responsible for implementing, negotiating, managing and administering various

[1437] Ex. SCE – 08, p.47

[1438] Ex. SCE – 08, p.48

[1439] Ex. SCE – 08, p..47

[1440] Ex. SCE – 08, p. 47, p. 48.

[1441] 20 RT 3276:20 – 3277:28, Cini/SCE.

legislative and regulatory initiatives such as California's RPS program, Public Utilities Regualtroy Power Act (PURPA), Combined Headt and Power (CHP) activities, the SCE RSC program and other contractual matters related to renewable and alternative power.[1442] SCE states that, in the future, RAP activities will be affected by the expansion of policy goals related to the procurement of power from both renewable and alternative resources. These include the increases in RPS program goals and additional regulations and program goals regarding CHP generators as well as the expansion of FIT programs.

RAP's workload is largely based on the amount of renewable and alternative power projects that are under contract with SCE – for projects that are either under development or actually operating – and the number of contracts that are under development with a counter-party for such projects.[1443]

The data shows that SCE's current PPBU employees were fully equipped and able to procure renewable resources of almost 5% of SCE retail services in one year from 2009 to 2010.[1444] SCE's renewable resources as a percentage of its retail sales increased from 16.8% to 19.4% in that period. Increasing SCE's procurement and management of renewable resources as a percentage of retail sales from 19.4% in 2010 to 33% in 2020 would require SCE to add only 1.36% of new renewable resources each year. Table 14-4 in Exhibit 14 shows that SCE's existing MS&RP employees have been able to exceed this level of procurement for most of the years since Renewables Portfolio Standard (RPS) program implementation began in 2003.[1445] SCE's testimony in fact admits that a substantial portion of the contracts it would use to meet the 33% requirement have already been executed:

> In addition, SCE has contracted for more than 3000MW solar projects, which will be brought on line in the next five to six years subject to CPUC approval.[1446]

[1442] RAP is responsible for renewables procurement and administration for RPS-eligible resources as well as "alternative" resources such as PURPA-QFs, CHP, and Carbon Sequestration.

[1443] Ex. SCE-8, p. 65.

[1444] Ex. 31 California Public Utilities Commission Renewable Portfolio Standard (RPS) large IOU Procurment Data.

[1445] Ex. DRA-14, p. 10.

[1446] Ex. SCE-8, p. 15.

SCE also argues that its advocacy activities at the various regulatory agencies support the addition of several new positions. This claim is unfounded. SCE has provided no information or data to correlate the number of regulatory proceedings to the number of employees that handled them in the past. Besides, as new proceedings are opened, old proceedings close. It is simply too speculative to base the addition of any one new positions on advocacy before the Commission.

Notwithstanding the fact that SCE has failed to justify its need for new employees within RAP, DRA recommends the addition of 2 new positions, one each for the renewable contract procurement group and regulatory and legislative advocacy group.

10.4. Power Procurement and Finance Department

DRA recommends $16,610,000 for the Power Procurement Finance (PPF) Department for Test Year 2012. This is $1,114,000 less than SCE's estimate of $17,724,000. The PPF Department performs wholesale procurement settlement, accounting and financial reporting, administrative support, budgeting, information management, and business process and systems development activities ("back office" activities) essential to support the supply of reliable electricity to SCE's customers.[1447] Labor costs for PPF were relatively stable from 2005 through 2007 but PPF began to increase staffing levels in 2007. By 2009, PPF had 40 plus employees over 2006 levels[1448]. The reason for this rate of expansion at PPF is not explained in SCE's testimony. Changes in electricity markets and renewable energy procurement are not compelling justifications for this expansion. It should be noted that incremental labor expenses related to changes in the electricity market are part of costs for implementing CAISO's MRTU initiative which are also being requested in another proceeding. Therefore, the Commission should be conservative in authorizing new positions for the further expansion of PPF. SCE requests 18 new positions for the PPF Department for Test Year 2012 and DRA recommends ratepayer funding for no more than eight new positions. Seven of the 8 positions fall within the area described by SCE as "others," which covers compliance requirements, administration support, changes in accounting standards, supporting implementation of capital projects. The remaining position falls within the environmental area. The seven positions in the "others" area are part of

[1447] Ex. SCE-08, p. 92.

[1448] Ex. DRA – 14, p.43

eleven positions identified by SCE in a data request response.[1449] This response shows that the total labor costs for the eleven positions amounts to $1,257,000 for Test Year 2012.

DRA notes that SCE provided recorded average monthly employees for the PPF Department for 2009 and 2010 (the latest year).[1450] This data shows average employees of 80 in 2009 and about 87 in 2010, for an increase of only 7. Based on this, DRA recommends that only 7 of the 11 "others" new positions be allowed for Test Year 2012. This amounts to reducing 4 of the 11 employees or about 36.4%. Taking 36.4% of the total labor and non-labor cost for 2012 for the 11 positions of $1,257,000 yields a reduction to SCE's forecast of $457,000.

Adding the reductions for the 4 "others" employees with the DRA adjustments discussed above gives the following: $219,000 for 2 positions in the Settlements Division; $438,000 for 4 positions in the BP&TI Division; and $457,000 for 4 positions in the "others" area, for a total labor and non-labor reduction of $1,114,000 compared to SCE's Test Year labor and non-labor forecast of $17,724,000. Thus DRA's recommended Test Year total is $17,724,000 minus $1,114,000 or $16,610,000 for Test Year 2012. This represents a reduction of 10 of the 18 new positions requested by SCE for the PPF Department for 2012.[1451]

11. Operations Support

SCE's Operations Support Business Unit (OSBU) provides support and resources for SCE's business operations and functions. The OSBU manages and maintains buildings, offices, yards, land, and land rights throughout SCE's service territory; SCE's OSBU employees do not generally interact directly with SCE's customers.[1452]

SCE is requesting a total of $112.525 million in 2012, which is $27.925 million or 33% above 2009 recorded expenses for OSBU's Administrative and General (A&G) expenses. DRA recommends $80.765 million, or 39% less than SCE's request.[1453] The areas where DRA disagrees with SCE's expense forecasts are discussed below.

SCE is also forecasting a total of $903.693 million in capital expenditures over the years 2010 through 2014. SCE's forecast is for $224.961 million in 2010, $204.748 million in 2011,

---

[1449] Ex. DRA-14, p. 52, citing Response to DRA-SCE-248-MBE (PPF), Q/A 1.

[1450] Ex. DRA-14, p. 52, citing Response to DRA-SCE-210-SCE-MBE, Q./A 1.b.

[1451] Ex. DRA-14, p. 52.

[1452] Ex. DRA-11, p. 1.

[1453] Ex. DRA-11, p. 4.

and $202.496 million in 2012.[1454] DRA recommends a forecast of $162.429 million in 2010, $89 million in 2011 and $89 million in 2012.[1455]

11.1. Corporate Environment, Health and Safety

SCE's Corporate Environment, Health and Safety (CEH&S) is responsible for anticipating, identifying, analyzing, and coordinating compliance with environmental, health, and safety requirements. SCE is requesting $12.955 million for TY 2012, which is $4.514 million above SCE's 2009 recorded expenses of $8.441 million.[1456] DRA recommends $8.249 million for TY 2012.[1457]

11.1.1. FERC Accounts 920/921 – Corporate Environment, Health & Safety

SCE's Corporate Environment, Health and Safety Department (CEH&S) uses FERC Accounts 920/921 to record labor and non-labor related expenses for developing and implementing programs and policies to comply with federal, state, and local environmental, health, and safety requirements.[1458]

For the Test Year, SCE is requesting $7.280 million, or $2.078 million above its 2009 recorded expenses for FERC Accounts 920 and 921.[1459] SCE gives three reasons for requesting additional funding over 2009 recorded for the CEH&S Department.

First, SCE forecasts additional funding to address what it describes as new environmental, health and safety regulatory requirements impacting both existing and new or replacement facilities and infrastructure such as above-ground storage tank regulations, construction storm water management regulations, and air quality regulations. Second, SCE forecasts additional staffing to meet the business needs from new and increased operations and maintenance associated with completed capital projects. Third, SCE forecast an increased number of environmental assessments and other related services to support expanded operations, infrastructure replacement, and new transmission and generation facilities.[1460]

[1454] Ex. SCE-9, Vol. 3, p. 1.0

[1455] Ex. DRA-11, p. 34.

[1456] Ex. SCE-9, Vol. 2, p. 5.

[1457] Ex. DRA-11, p. 5, Table 11-4.

[1458] Ex. SCE-9, Vol. 2, p. 16.

[1459] Ex. SCE-9, Vol. 2, p. 19.

[1460] Ex. SCE-9, Vol. 2, p. 20.

SCE is requesting $7.280 million which is $2.078 million or 39.9 percent above 2009 recorded expenses for FERC Accounts 920 and 921.[1461] SCE provides three reasons for CEH&S's additional funding request.

First, SCE forecasts additional funding to address new environmental, health and safety regulatory requirements impacting both existing and new or replacement facilities and infrastructure such as above-ground storage tank regulations, construction storm water management regulations, and air quality regulations. Second, SCE forecasts additional staffing to meet the business needs from new and increased operations and maintenance associated with completed capital projects. Third, SCE forecast an increased number of environmental assessments and other related services to support expanded operations, infrastructure replacement, and new transmission and generation facilities.[1462]

DRA recommends a forecast of $5.202 million which is $2.078 million or 28.5 percent less than SCE's forecast for FERC Accounts 920 and 921 for CEH&S for TY 2012. DRA recommends using the 2009 recorded amounts to forecast CEH&S's labor expenses of $3.308 million recorded in FERC Account 920 and non-labor expenses of $1.894 million recorded in FERC Account 921.

Labor Expenses

SCE is requesting labor expenses of $4.788 million which is an increase or a 45% increase above its 2009 labor expenses. DRA recommends using the 2009 recorded labor expenses of $3.308 million as the TY 2012 labor forecast expenses.[1463]

DRA's reasons are as follows. First, CEH&S' historical labor expenses recorded in FERC Account 920 show a high of $3.561 million in 2006 to a low of $3.064 million in 2008. CEH&S labor has remained stable even though SCE states that the number of environmental projects supported by CEH&S, both capital and Operation and Maintenance (O&M), has increased from less than 100 in 2005 to 1,281 in 2009.[1464] SCE states that about 98 percent of the increase in environmental projects represents Transmission and Distribution Business Unit (TDBU) work.

[1461] Ex. SCE-9, Vol. 2, p. 19.

[1462] Ex. SCE-9, Vol. 2, p. 20.

[1463] Ex. DRA-11, p. 7.

[1464] Ex. SCE-9, Vol. 2, p. 20.

Second, CEH&S should not receive funding for additional staff because SCE's TDBU has its own dedicated environmental staff to perform environmental assessments and other duties as well as in CEH&S.[1465]

Third, some of the environmental regulations that SCE requests additional staffing to comply with were adopted prior to 2009 and activities associated with these regulations should be embedded in recorded expenses. These include:

- The amendment to the California Aboveground Petroleum Storage Act (ASPA) was implemented before January 1, 2008 and SCE is in compliance with the regulation.[1466]
- The New Source Review Permit Program is a federal Clean Air Act requirement that has been in effect since 1977. The California Clean Air Act was adopted in 1988.[1467] SCE has processes in place for roles and responsibilities pertaining to Permits to Construct and Permits to Operate for each of the air districts.[1468]
- SCE already has a Monitoring Plan to report greenhouse gas emissions to the U.S. Environmental Protection Agency.[1469]
- SCE has several guidelines and procedures in place for Air Quality Compliance for Non-Generation and Generation.[1470]
- SCE has had to comply with storm water regulations which are a subset of the Clean Water Act that was enacted by Congress in 1972.[1471]

In Rebuttal, SCE argues that "... increases in environmental compliance activity require additional staffing and specialized services (such as agency-certified contractors) to achieve and confirm compliance. Unfortunately, due to inadequate staffing, SCE has not been able to keep pace with increasing compliance obligations and has received an increasing and unacceptable number of Notices to Comply (NTCs) and Notices of Violation (NOVs) since its response to the

---

[1465] Ex. DRA-11, p. 7 citing SCE's response to DRA-SCE-121-SWC, Question 3.d.

[1466] Ex. SCE-9, Vol. 2, p. 10; Ex. DRA-11, p. 8 citing SCE's response to DRA-SCE-121-SWC, questions 2.a. and 2.d.

[1467] Ex. SCE-9, Vol. 2, p. 21; Ex. DRA-11, p. 8 citing SCE's response to DRA-SCE-41-SWC, Q/A 2.a.

[1468] Ex. DRA-11, p. 8 citing SCE's response to DRA-SCE-41-SWC, Q/A 2.b.

[1469] Ex. SCE-9, Vol. 2, p. 22; Ex. DRA-11, p. 8 citing SCE's response to DRA-SCE-41-SWC, Q/A 3.b.

[1470] Ex. SCE-9, Vol. 2, pp. 23 and 24; Ex. DRA-11, p. 8 citing SCE's response to DRA-SCE-41-SWC, Q/A 6.a. and 7.a.

[1471] Ex. SCE-9, Vol. 2, p.29, and Ex. DRA-11, p. 8, citing SCE's response to DRA-SCE-121-SWC, Q/A 7.a.

November 2010 Data Request set."[1472] SCE offers no evidence to show that the "increasing" number of NTCs and NOVs is "due to" anything in particular, and certainly not to "inadequate staffing."

Fourth, DRA disputes SCE's request for an increase of $123,900 to hire one full-time program/project manager in the biological and archaeological staff to support environmental compliance for non-capital business unit operations, general EH&S oversight, and external liaison functions.[1473] DRA recommends that this $123.900 not be authorized. SCE has employed staff and managers in the biological and archaeological department during the period 2005 to 2009[1474] and thus already has embedded recorded expenses for staff.

Non- Labor Expenses

SCE is requesting $2.492 million which is an increase of $598,000 above 2009 recorded non-labor expenses for FERC Account 921 for CEH&S. DRA recommends using the 2009 recorded non-labor expenses of $1.894 million as the forecast.[1475]

DRA disputes SCE's request for $500,000 of non-labor expenses for environmental studies to: (1) support improved models of temperature and load demands; (2) leverage best practices for achieving company compliance with environmental regulations; and (3) support maintenance of software tools for environmental field work and siting decision support.[1476]

First, CEH&S should not receive funding for an activity that another SCE business unit is obligated to provide and receives funding to perform. SCE's Power Supply Business Unit performed temperature and load forecasting during the period 2005 to 2009. SCE states that these other business units of SCE have an operational obligation to perform load forecasting and wind and solar generation.[1477]

[1472] Ex. SCE-24, Vol. 1, p. 5.

[1473] Ex. SCE-9, Vol. 2, p. 27.

[1474] Ex. DRA-11, p. 9, citing SCE's response to DRA-SCE-41-SWC, Q/A 11.b.

[1475] Ex. DRA-11, p. 9.

[1476] Ex. SCE-9, Vol. 2, p. 25.

[1477] Ex. DRA-11, p. 9 citing SCE's response to DRA-SCE-121-SWC, Q/A 5.b. and 5.c.

Second, CEH&S has embedded recorded cost for environmental studies. CEH&S recorded non-labor expenses of $1.166 million for the five years of 2005 to 2009, or an average of $233,000 per year for environmental studies.[1478]

Third, TDBU Research Development and Demonstration (RD&D) provides funding for environmental studies.[1479]

Fourth, since DRA recommends disallowing SCE's request for additional staffing, additional non-labor expenses associated with these additional staff is not be needed.

11.1.2. FERC Account 923 – Corporate Environment, Health & Safety

SCE's CEH&S uses FERC Account 923 to record non-labor expenses for discrete CEH&S projects and materials that require specialized areas of expertise such as activities that cannot be performed by internal staff in a cost-effective manner.

SCE is requesting non-labor expenses of $1.503 million which is an increase of $1.009 million or 80% over 2009 recorded expenses.[1480] SCE's proposed increase is made up of $564,262 of non-labor external services for environmental and safety compliance-related support,[1481] $245,000 of non-labor, non-capital external services for environmental review support within its Environmental Projects section,[1482] and $200,000 of non-labor to support developing and maintaining environmental GIS databases.

DRA recommends using the five-year average of recorded expenses (2005 to 2009), $302,000, to forecast CEH&S' non-labor expenses for FERC Account 923. The recorded expenses for FERC Account 923 varied significantly during 2005 to 2009 from a low of $0 in 2005 to a high of $677 in 2007. The five-year averages of recorded non-labor expenses provide an appropriate forecast for funding of activities in this account.

[1478] Ex. DRA-11, p. 10, citing SCE's response to DRA-SCE-41-SWC, Q/A 10.a.

[1479] Ex. DRA-11, p. 10, citing SCE's response to DRA-SCE-41-SWC, Q/A 10.b.

[1480] Ex. SCE-9, Vol. 2, p. 31.

[1481] Ex. SCE-9, Vol. 2, p. 32.

[1482] Ex.SCE-9, Vol. 2, p. 33.

11.1.3. FERC Account 925 – Corporate Environment, Health & Safety

CEH&S uses FERC Account 925 to record labor and non-labor expenses for its Corporate Safety section. SCE is requesting $4.172 million which is an increase of $1.427 million over 2009 recorded expenses for FERC Account 925.[1483]

DRA recommends using the 2009 recorded expenses of $2.745 million as the forecast for TY 2012.

Labor Expenses

SCE is requesting $2.623 million in 2012 which is an increase of $541,000 or 26 percent over 2009 recorded expenses for labor expense for FERC Account 925. DRA recommends using 2009 recorded labor expenses of $2.082 million as the forecast TY 2012 labor expenses.

SCE's CEH&S FERC Account 925 labor expenses have significantly increased from a low of $800,000 in 2005 to a high of $2.082 million in 2009. SCE's labor expenses stabilized during 2008 at $1.951 million and 2009 at $2.082 million.

SCE seeks the increase of $541,000 to fund an addition of five employees in 2012 to support a proposed restructuring of Corporate Safety. SCE has not shown why its ratepayers should be required to fund this additional staff.[1484] SCE has well established company-wide safety programs and has not shown why it cannot use the funding it already has to "ensure proper implementation of safety programs and initiatives to maintain compliance and reduce injuries within the Company's business units."[1485] As a matter of fact, SCE's Occupational Safety and Health Administration (OSHA) rates show that the overall OSHA rates have declined since 2005.

Non-Labor Expenses

In its Application, SCE requested an increase of $935,000 in non-labor expenses over 2009 recorded expense levels. Of the $935,000, $35,000 is for non-labor expenses of the additional five employees SCE is requesting, approximately $300,000 is to support and expand the company-wide Safety Culture program through focus groups, interviews and initiatives,[1486] and $600,000 is to support participation in the Electric Power Research Institute's (EPRI)

[1483] Ex. SCE-9, Vol. 2, p. 35.

[1484] Ex.SCE-9, Vol. 2, p. 38

[1485] Ex. SCE-9, Vol. 2, p. 38.

[1486] Ex. SCE-9, Vol. 2, p. 36

Electromagnetic Field (EMF) Research Program 60A and EPRI's Occupational Health Research Program.

DRA recommends using the 2009 recorded non-labor expenses of $663,000 as the TY 2012 forecast. In its testimony, DRA disputed SCE's request of an increase $400,000 to support EPRI's EMF research program. SCE's 2005 to 2009 expenses for EPRI were recorded in SCE's Transmission and Distribution Business Unit's Research, Development and Demonstration's balancing account and not in CEH&S.[1487] In Rebuttal, SCE seems to have withdrawn that request.[1488]

DRA disputes SCE's remaining request for a $335,000 for non-labor expenses associated with the five additional employees discussed above and $300,000 for follow-ups to Safety Culture Assessments. SCE has not explained why its current funding levels are inadequate to perform these functions. Perhaps instead of continuously asking for increases at its ratepayers expense, SCE can assess how to use the funding it receives more effectively.

11.2. Corporate Resources

SCE's Corporate Resources is responsible for all activities related to managing SCE buildings, including the planning, design, construction, relocation management and maintenance of 221 non-electric facilities within its service territory.[1489] Corporate Resources was created in 2009 by combining portions of the former Corporate Real Estate and Business Resources organizations.[1490]

SCE is requesting $55.512 million in TY 2012 for Corporate Resources, which is $10.779 million above 2009 recorded expenses of $44.733 million.[1491] DRA recommends $47.358 million for the Test Year.

The discussion that follows focuses on the FERC Accounts where DRA has differences with SCE's TY 2012 forecasts for Corporate Resources.

[1487] Ex. DRA-11, p. 14, citing SCE's response to DRA-SCE-41-SWC, Q/A 18.a.

[1488] Ex. SCE-24, Vol. 2, p. 14.

[1489] Ex. SCE-9, Vol. 2, pp. 44-45.

[1490] Ex. SCE-9, Vol. 2, p. 52.

[1491] Ex. SCE-9, Vol. 2, p. 44.

11.2.1. FERC Accounts 920/921 – Corporate Resources

Corporate Resources records the Administrative and General costs of managing SCE buildings, and the maintenance of all non-electric facilities. SCE created Corporate Resources in 2009 by combining portions of the former Corporate Real Estate (CRE) and Business organizations. The Corporate Real Estate department itself underwent an internal reorganization in 2007 to 2008. As a result of these reorganizations, SCE states that 2008 and 2009 recorded costs serve as the most representative recorded costs for the currently-organized Corporate Resources Department.[1492] SCE is seeking $31.860 million for Corporate Resources in 2012. DRA recommends $27.390 million, split equally between labor and non-labor costs.[1493]

As of 2009, Corporate Resources is comprised of the following departments:

- Department Management was formed in October 2009 to combine portions of the former Corporate Real Estate and former Business Resources to accumulate overhead costs at the department management level.[1494]
- Facility Asset Management is responsible for the ongoing operation and maintenance of SCE's 221 buildings such as janitorial, landscaping, building maintenance and repair work.[1495]
- Engineering and Construction manages the construction and remodel activities associated with SCE's non-electric buildings.[1496]
- Space Planning & Management has operational responsibility for relocating employees.[1497]
- Facility Planning provides strategic and operational facility planning services.[1498]
- Business Resources provides support services to the occupants of the non-electric facility buildings such as drawing management, corporate records storage, mailing services, graphics production, corporate travel management, and meeting/event logistics.[1499]

[1492] Ex. SCE-9, Vol.2, pp. 52 and 53.

[1493] Ex. DRA-11, p. 17.

[1494] Ex. SCE-9, Vol. 2, p. 53.

[1495] Ex. SCE-9, Vol. 2, p. 46.

[1496] Id. at p. 47.

[1497] Id. at, p. 48.

[1498] Id.

[1499] Id., at p. 49.

- Business Services provide support in the areas of vendor and purchase order management; master data support; reporting for organizational key performance indicators and metrics; and financial work order support.[1500]

SCE forecasts $31.860 million for TY 2012. SCE arrives at this amount by using its 2009 recorded expenses and adding to that for what it describes as "known changes that primarily relate to expenses required to support the approximately 1 million square feet of facility space [SCE] needs to support the growth of SCE's workforce."[1501] Due to the numerous organizational changes that led to the current Corporate Resources structure, SCE was unable to provide an exact comparison of the 2005 to 2010 recorded expenses for Corporate Resources as it is currently organized in 2010.

As noted throughout DRA's testimony and this Brief, DRA disputes SCE's grandiose plans to expand its workforce and its facilities at ratepayer expense. DRA, therefore, recommends using 2010 recorded expenses of $27.390 million because this year provides the best representation of expenses and activities of the current structure of Corporate Resources.

The recorded expenses in FERC Accounts 920 and 921 rose from 2005 to 2009 when SCE started reorganizing Corporate Resources in 2007. The previous structure of Corporate Resources recorded expenses of $15.213 million in 2005. Starting in 2008, the recorded expenses of FERC Accounts 920 and 921 rose to $23.869 million in 2008. Once Corporate Resources reorganized to its current structure, the recorded expenses stabilized at $26.347 million in 2009 and $27.390 million 2010.

Since its latest reorganization, staffing in Corporate Resources has been consistent: 221 SCE employees in 2009 and 216 SCE employees in 2010.[1502]

One factor in the increase in 2008 and 2009 recorded expenses for Corporate Resources is the Space Planning and Management department. The Space Planning and Management department showed a significant increase in activity during 2005 to 2010. The recorded expenses in the Space Planning and Management department did not start recording expenses until 2008 when expenses rose from $846,000 in 2008 to $6.383 million in 2010. One reason is that Corporate Resources did not coordinate all of SCE's employee moves during 2005 to 2009.

[1500] Id., at p. 51.

[1501] Ex. SCE-24, Vol. 1, p. 16.

[1502] Ex. DRA-11, p. 20.

Prior to 2009, employee moves were performed by SCE's individual business units which means that recorded expenses for employee moves are embedded in the 2005 to 2009 recorded expenses of SCE's individual business units. SCE states that it did not coordinate all employee moves through Corporate Resources until 2010.[1503] SCE did not show in its testimony that it removed the embedded recorded expenses for 2005 to 2009 employee moves from SCE's individual business units before requesting incremental funding for Corporate Resources for all employee moves for TY 2012.[1504]

In Rebuttal, SCE says it took employee-move expenses out of its TDBU 2009 adjusted costs and "[h]ad DRA requested the information during discovery, SCE would have gladly provided the detail of this transaction."[1505] SCE's decision to provide relevant information only if specifically asked, or wait until Rebuttal to disclose it at all means that DRA has not had the time to independently verify SCE's claim.

Therefore, DRA continues to recommend that the Commission adopt SCE's 2010 recorded expense level.

11.2.2. FERC Account 931 – Rents

Corporate Resources records rental and/or lease costs of property and buildings that SCE uses, occupies, or operate, but does not own.[1506] SCE is requesting $15.814 million for TY 2012, which is an increase of $5.266 million or 50% over 2009 recorded expenses. DRA recommends using $12.130 million, which is the 2010 recorded expenses to forecast TY 2012 for FERC Account 931.[1507] The reasons for DRA's disagreement with SCE's forecast are as follows.

First, DRA recommends no ratepayer funding for SCE's request of $312,000 for annual rent of a new third Customer Service Business Customer Energy Center in TY 2012. SCE's two existing Energy Centers have made seminars and workshops available for SCE's customers through on-site and off-site locations. With the other alternatives SCE has considered for offering there is no need at this time for ratepayers to fund a third Energy Center.[1508]

[1503] Id.

[1504] Ex. DRA-11, p. 20.

[1505] Ex. SCE-24, Vol. 1, p. 19.

[1506] Ex. SCE-9, Vol. 2, p. 63.

[1507] Ex. DRA-11, p. 21,citing SCE's response to DRA-SCE-131-SWC, Q/A 1.a.

[1508] Ex. DRA-11, p. 22. See also, Section 6.3.2 of this Brief.

Second, DRA recommends using 2010 recorded expenses for rent because the recorded year-end 2010 number and the forecasted year-end 2012 number of SCE employees and contingent workers are very similar. SCE states that it expects to add 1,677 additional staff over 2009 recorded levels by year-end 2012, which SCE says translates to the need for incremental seats and office space.[1509] The recorded year-end 2010 headcount number is 26,256 and the forecasted year-end 2012 headcount number is 26,362, a difference of only 106 workers.[1510] SCE did not track the number of contingent workers prior to 2008 and the number of other support personnel prior to 2009.[1511]

Third, SCE's forecast of additional employees is higher than DRA's forecast recommendation of additional employees based on recommended O&M expense levels, administrative and general expenses, and capital projects for TY 2012.

Fourth, SCE has several capital projects such as the General Office 5 (GO5) building and Pomona Innovation 3 building which will accommodate approximately 1,150 employees once they are completed in 2011.[1512] SCE closed escrow on GO5 in February 2010 and the Pomona Innovation 3 building lease was also completed in 2010. The rents of these building are embedded in 2010 recorded rent expenses.[1513]

In Rebuttal, SCE says DRA "…failed to account for lease contract obligations."[1514] SCE refers to a response to a data request in which SCE provided copies of the lease agreements for all current office leases as of the 2nd quarter of 2010 and says that, "[i]t appears DRA did not even review these responses because DRA does not even attempt to explain why the binding contractual terms of the leases should not control."[1515]

The fact that SCE chose to sign a lease agreement does not mean the Commission must order ratepayers to pay the costs of that lease. If the property is not necessary or useful in the

---

[1509] Ex. SCE-9, Vol. 2, p. 45.

[1510] Ex. DRA-11, p. 22.

[1511] Id.

[1512] Ex. SCE-9, Vol. 3, pp.18 – 20.

[1513] Ex. DRA-11, p. 23.

[1514] Ex. SCE-24, Vol. 1, p. 22.

[1515] Id.

provision of utility service to ratepayers, then ratepayers should not have to pay for it. DRA's forecast includes the 2010 lease costs for the locations SCE identified as covered by leases.[1516]

It now appears, however, that DRA's estimate may be overstated since one of these properties, the San Francisco office is used by SCE's lobbyists and SCE's ratepayers should most assuredly not be paying for that.[1517] DRA continues to recommend the Commission authorize ratepayer funding of no more than $12.13 million for FERC Account 931 for TY 2012.

11.2.3. Corporate Resources Additional Facilities – Capital Expenditures

SCE is requesting $37 million in 2012 for Corporate Resources Additional Facilities.[1518] DRA recommends zero ratepayer funding for these capital projects in 2012.[1519]

In addition to the $37 million SCE is seeking in 2012, SCE also forecasts $66.125 million in 2013 and $23.625 million in 2014. Consistent with the Commission's decision in D.09-03-025 rejecting budget based forecasts for post test years,[1520] DRA's recommendations for capital expenditures after 2012 are addressed in Section 16 of this Brief.

SCE's says the millions of ratepayer dollars it seeks for "additional facilities" are due to increased demands for space occasioned by:

- Changing regulatory requirements;
- Infrastructure growth and replacement programs; and
- Emerging corporate initiatives such as SmartConnect and its TDBU's advanced Technology efforts to advance the Smart Grid and PEVs.

SCE is projecting an increase of 1,677 SCE employees, contingent workers and other supporting personnel between 2009 and 2012. SCE states that one factor is SCE's headcount forecast; however, the other factor is the number of "seated" and "non-seated" jobs.[1521] SCE forecasts an increase of 3,000 seated employees between 2009 and 2012.[1522] According to SCE, the reduction of approximately 600 "non-seated" meter readers, and the increase of 200 Rubber

---

[1516] Ex. DRA-11, p. 22; Ex. DRA-65; 19 RT 3033-3035, D.Wilson/SCE.

[1517] 19 RT 3071-3073, D.Wilson/ SCE.

[1518] Ex. SCE-9, Vol. 3, p. 13.

[1519] Ex. DRA-11, p. 40.

[1520] D.09-03-025, mimeo, p. 304.

[1521] Ex. SCE-9, Vol., p. 3.

[1522] Id. at pp. 2 and 3.

Glove-Tested Linemen in TDBU would distort the amount of office space needed.[1523] This would result in an additional 400 "seated" employees not directly associated with headcount growth.[1524] SCE's request for $37 million in 2012 for Corporate Resources Additional Facilities is to house SCE's forecast of growth of 2,147 employees during the 2010 to 2014 timeframe.[1525]

SCE's proposed New Building Projects are:

- New Office Buildings-Metro which SCE says is expected to support the projected growth of 1,070 seated employees in TDBU. SCE forecasts $12 million in 2012.[1526] Corporate Resources plans to construct 250,000 square feet of new office space to accommodate 900 employees during the 2010 to 2014 timeframe. Corporate Resources expects to construct two new building to begin in 2012.
- New Office Buildings-Orange County which SCE says is expected to house approximately 400 employees that will be relocated from other SCE buildings. SCE is requesting funding to acquire an office building in Orange County of approximately 100,000 square feet. SCE forecasts capital expenditures of $25 million in 2012.[1527]

DRA recommends the Commission reject the entire $37 million of capital expenditures in 2012 for the Corporate Resources Additional Facilities project. The evidence does not support funding at this level at this time.

SCE's recorded year-end 2010 number of SCE employees, contingent workers, and other supporting personnel was 26,256. SCE's forecast total of SCE employees, contingent workers, and other supporting personnel at the year-end 2012 is 26,362 which is only 106 workers above the recorded 2010 headcount number.[1528] As of the end of 2010, SCE was able to provide office space for the 26,256 SCE employees, contingent workers, and other support personnel.

As DRA noted in its testimony, if the number of "seated" and "non-seated" employees does distort the amount of office space needed, two of SCE's capital projects should provide additional office space for 1,150 employees in 2011. First, SCE closed escrow on the General Office 5 (GO5) building in February 2010. The GO5 building can accommodate 700 employees

---

[1523] Id. at p. 3.

[1524] Id. at p. 14.

[1525] Id. at pp. 13 to 14.

[1526] Id at pp. 14 and 15.

[1527] Ex. SCE-9, Vol. 3, pp. 15 and 16.

[1528] Ex. DRA-11, p. 39, citing SCE's response to DRA-SCE-124-SWC, Q/A 1.a. and 1.b.

when completed in 2011.[1529] Second, SCE purchased the approved plans, permits and ground lease in 2010 from a developer for the Pomona Innovation 3 building. The Pomona Innovation 3 building can accommodate 450 employees when completed in 2011.[1530] As discussed earlier, the 2010 recorded headcount number is only 106 employees less than the forecasted 2012 headcount number. These two buildings to be completed in 2011 should more than accommodate additional demand for office space by "seated" employees.

Therefore, DRA is recommending the rejection of $37 million of capital expenditures for 2012.

11.2.3.1. Alhambra Data Center – Capital Expenditures

SCE's two data centers are part of its non-electric critical facilities.[1531] The Rosemead Data Center (RDC) is located in the GO2 building at SCE's headquarters campus in Rosemead. SCE is planning a new data center facility on land currently owned by SCE in Alhambra, California. SCE forecasts $28.200 million in 2010, $66.100 million in 2011, and $8.700 million in 2012 of capital expenditures for the Alhambra Data Center.[1532] SCE has recorded $6.830 million of capital expenditures in 2010 for the Alhambra Data Center.[1533]

SCE acknowledges that the data center replacement project was originally presented in SCE's 2006 GRC at a total forecast of $31.5 million in capital expenditures to replace the physical building. Some improvements were made to the building, but the project was deferred by SCE's senior management and the ratepayer funds reallocated to other capital investments.

The data center replacement project was again presented in SCE's 2009 GRC at a total forecast of $39.974 million to construct an Annex adjacent to the RDC to take critical load off the existing building. In the 2009 GRC, SCE also requested $22.8 million in Information Technology (IT) capital expenditures for refresh of the RDC computing equipment. Both the

---

[1529] Ex.SCE-9, Vol. 3, p.18 to 20, and Ex. DRA-11, p. 39, citing Response to DRA-SCE-148-SWC, Q/A 1.a.

[1530] Ex. SCE-9, Volume 3, p.18 to 20, and Ex. DRA-11, p. 39 citing Response to DRA-SCE-148-SWC, Q/A 1.a.

[1531] Ex SCE-9, Vol. 3, p. 35.

[1532] Id. at p. 36.

[1533] Id. at p. 18 to 20, and Ex. DRA-11, p. 40 citing Response to DRA-SCE-148-SWC, Q/A 1.a.

2006 and 2009 GRCs adopted funding for the data center replacement project. Again, the data center replacement was delayed by SCE's senior management.[1534]

DRA opposes ratepayer funding of the $66.100 million in 2011, and $8.700 million in 2012 in capital expenditures for the Alhambra Data Center project. In its TY 2006 GRC, SCE told the Commission the need for this project was "critical,"[1535] and the Commission authorized ratepayer funding for it.

In the TY 2009 GRC, SCE again told the Commission the need for this project was "critical" and again the Commission authorized funding for it. Now, SCE is back telling the Commission again that the same project, for which SCE has been authorized funding twice and never completed, is "critical."[1536] SCE says that this new, more expensive, project is a "different solution" than the $39.974 million solution presented in the 2009 GRC.[1537] Whether this is a "different solution" or not, SCE has already twice received ratepayer funding to replace the same data center. The Commission should reject this latest repetitive demand.[1538]

11.2.3.2. Customer Energy Center – Capital Expenditures

SCE is requesting $3.250 million of capital expenditures in 2012 to add a third Customer Energy Center. DRA recommends no ratepayer funding for the project. DRA's reasons for this recommendation are discussed in more detail above in Section 6.3.2 of this Brief.

SCE has two Energy Centers called the Customer Technology Application Center (CTAC) and the Agricultural Technology Application Center (AGTAC).[1539] SCE's two existing Energy Centers have made seminars and workshops available for SCE's customers through on-site and off-site locations.

SCE's proposed capital expenditures of $3.250 million in 2012 should be rejected.

11.2.3.3. Service Center Modernization – Capital Expenditures

SCE is requesting $10.0 million of capital expenditures in 2012 to fund SCE's Service Center Modernization program which is designed to address operational and asset preservation

---

[1534] Ex. SCE-9, Vol. 1, p. 40.

[1535] 19 RT 3037, D.Wilson/ SCE.

[1536] Ex. DRA-66; 19 RT 3037, D.Wilson / SCE.

[1537] Ex.SCE-9, Vol.3, p. 40.

[1538] Ex. DRA-11, p. 40-41.

[1539] Ex. SCE-4, Vol. 3, p. 49.

needs at its 36 SCE Service Centers. SCE lists the following five service centers that need modernization during 2012 to 2014:

- San Joaquin
- Santa Ana
- Fullerton
- Redlands
- Ontario

DRA recommends no ratepayer funding for SCE's proposed $10.0 million of capital expenditures in 2012 for the Service Center Modernization program. Two of these service centers, Santa Ana and Ontario, for which SCE is requesting capital funding in this 2012 GRC, were also capital projects for which SCE requested funding for in the 2009 GRC. In the 2009 GRC, SCE requested capital funding of $48.700 million to replace or renovate ten service centers in 2009 on a project called Field Facility Modernization Program.[1540] SCE recorded capital spending of $1.7 million for one of the 2009 GRC service center projects.[1541]

SCE cancelled seven of the 2009 GRC service center projects and deferred two of the 2009 GRC service center projects to 2012. The deferred 2009 GRC service center modernization projects were the Santa Ana service center and the Ontario service center. Based on the deferrals and cancellations of nine out of ten service center projects that SCE requested funding in the 2009 GRC, DRA questions the need for these service center modernization projects now.[1542]

11.2.3.4. Energy Efficiency – Capital Expenditures

SCE is requesting $5.0 million of capital expenditures for each year from 2010 to 2012 for programs to implement energy efficiency, sustainability, and conservation projects for SCE's non-electric building portfolio.[1543] SCE's OSBU recorded $1.447 million in 2009 and

---

[1540] Ex. DRA-66, SCE 2009 GRC, Exhibit SCE-10, Chapter X, pp. 2 and 3.

[1541] Ex. DRA-11, p. 42, citing SCE's response to DRA-SCE-156-SWC, Q/A 3.

[1542] Ex. DRA-11, p. 42.

[1543] Ex.SCE-9, Vol. 3, p. 110.

$2.342 million in 2010 of capital expenditures for Energy Efficiency projects.[1544] The 2009 GRC decision authorized $5.0 million annually for SCE's Energy Efficiency projects.[1545]

DRA disputes SCE's request for $5.0 million of capital expenditures for each year from 2010 to 2012 for Energy Efficiency projects and instead recommends $2.5 million. DRA's recommendation is consistent with SCE's spending for Energy Efficiency projects in 2010 of $2.342 million.[1546]

11.3. Corporate Security

SCE is requesting $22.167 million for TY 2012, which is $10.103 million or 84% above 2009 recorded expenses.[1547] DRA recommends a forecast of $11.970 million for 2012.[1548]

SCE's Corporate Security Department designs and integrates the strategies, plans, technologies, and behaviors that prepare SCE to meet known threats, extreme emergencies, and presently unrecognized vulnerabilities.[1549] Below DRA presents the reasons it disagrees with SCE's forecasts for FERC Accounts 920 and 921. DRA does not dispute SCE's forecast for FERC Account 923.

11.3.1. FERC Accounts 920/ 921 – Corporate Security

FERC Accounts 920 and 921 record the Administrative and General salaries and office supplies and expenses of Corporate Security. For FERC Accounts 920 and 921, SCE is requesting $22.073 million.[1550] DRA recommends using SCE's 2009 recorded expenses of $11.970 million to forecast TY 2012.

SCE says its projected increase takes into consideration the following:

- Compliance with North American Electric Reliability Corporation (NERC)-Mandated Critical Infrastructure Protection, Cyber Security Regulations;
- A projected increase of 1,677 employees in the SCE workforce between recorded 2009 headcount and TY 2012; and,

---

[1544] Ex. DRA-11, p. 43 citing SCE's response to DRA-SCE-156-SWC, Q/A 4.

[1545] Ex.SCE-9, Vol. 3, p. 110.

[1546] Ex. DRA-11, p. 43.

[1547] Ex. SCE-9, Vol. 2, p. 70.

[1548] Ex. DRA-11, p. 24.

[1549] Ex. SCE-9, Vol. 2, p. 70.

[1550] Ex. SCE-9, Vol. 2, p. 73.

- Corporate Commitment to improve business resiliency and emergency preparedness through program enhancement and capital investment.

DRA disputes SCE's argument that it needs incremental funding to comply with the North American Electric Reliability Corporation's (NERC) Critical Infrastructure Protection (CIP) standards that SCE anticipates will take effect in 2012.[1551] DRA agrees that FERC adopted a set of cyber security standards for Critical Infrastructure Protection (CIP) in 2007.[1552] FERC has adopted Versions 1 to 3 of NERC CIP standards. Version 3 of the CIP Standards was approved by FERC in an order dated March 31, 2010 and became effective October 1, 2010.[1553] SCE says that revisions to CIP standards – Version 4 are imminent, and new mandates will broaden the impact of such reliability standards on SCE's operations.[1554] SCE says about 40% of the Corporate Security expenses are to meet the NERC CIP regulations.[1555]

As of the time of the evidentiary hearings, FERC had not yet adopted Version 4 of the CIP standards, and SCE is in compliance with the current CIP standards. SCE is speculating as to when CIP Standards – Version 4 will be approved by FERC and the effective date of the standards. SCE is also speculating as to what type of standards will be adopted.

Moreover, SCE already has embedded 2005 to 2009 recorded costs for NERC-CIP driven expenses because SCE has planned, designed, and implemented NERC-CIP driven requirements as far back as 2005.[1556] SCE has incurred costs associated with compliance activities to comply with NERC CIP Versions 1 to 3.[1557] SCE has also incurred capital expenditures of $6.070 million during 2007 to 2009 to meet NERC CIP requirements.[1558]

In any event, it is not clear why SCE is seeking to charge its ratepayer for NERC CIP costs in this GRC when NERC/CIP costs are FERC jurisdictional.

[1551] Ex. SCE-9, Volume 2, p. 75.

[1552] Ex. DRA-11, p. 25.

[1553] Ex. DRA-11, p. 25.

[1554] Ex. SCE-9, Vol. 2, p. 75.

[1555] Ex. SCE-9, Vol. 2, p. 75.

[1556] Ex. DRA-11, p. 26.

[1557] Id.

[1558] Id.

Finally, DRA notes that the number of SCE employees rose from 15,850 in 2007 to 17,010 in 2009.[1559] Even with this increase in the number of employees, SCE's 2007 to 2009 recorded expenses for Corporate Security have remained consistent at approximately $11 million.

SCE has well-established security plans and programs in place as shown by the consistent expense level recorded during 2007 to 2009. Therefore, DRA continues to recommend that the Commission use SCE's 2009 recorded expenses of $11.970 million to forecast TY 2012.
In Rebuttal, SCE criticizes DRA for failing to accept SCE's "correlation between Corporate Security's Operating costs and the total number of SCE employees."[1560] DRA, in fact, does understand the correlation between SCE's inflated forecasts for Corporate Security costs to and SCE's inflated forecast of total number of employees for TY 2012. DRA's proposal for Corporate Security O&M costs is intended to be consistent with DRA's recommended revenue requirement which, in turn, is intended to remove expenses associated with SCE's unnecessarily inflated forecasts.

11.3.2. Critical Infrastructure Protection Physical Security Project – Capital Expenditures

SCE is requesting $24.200 million of capital expenditures in 2012 for the Critical Infrastructure Protection Physical Security Project. DRA is recommending $1.5 million of capital expenditures. DRA used the average of 2007 to 2010 recorded NERC CIP-driven capital expenditures of $1.5 million to forecast 2012 capital expenditures for the Critical Infrastructure Protection Physical Security Project.

As discussed above, Version 3 of the CIP Standards was approved by FERC in an order dated March 31, 2010 and became effective October 1, 2010.[1561] At the time of the evidentiary hearings, Version 4 of the CIP Standards still had not been adopted. Nor has SCE explained clearly why ratepayers should be ordered to fund NERC/ CIP capital costs in this GRC when these costs are FERC jurisdictional.

For all these reasons, DRA continues to recommends the Commission use the average of 2007 to 2010 recorded capital expenditures of $1.5 million to forecast 2012 capital expenditures.

[1559] Ex. DRA-11, p. 26.

[1560] Ex. SCE-24, Vol. 1, p. 31.

[1561] Ex. DRA-11, p. 25, citing SCE's response to DRA-Verbal-052, Q/A 1.

11.4. Transportation Services

11.4.1. Transportation Services Department -- Operations and Maintenance Expenses

SCE forecasts Transportation Services Department (TSD) Operation and Maintenance (O&M) chargeback costs of $137.5 million in 2012 which is 19% percent above SCE's 2009 recorded chargeback costs.[1562] SCE claims that the increase is primarily due to increases in fleet ownership cost ($10.7 million), fleet maintenance costs ($2 million), fuel costs ($7.4 million), and Aircraft Operations costs ($1.8 million).[1563] DRA recommends the Commission adopt a forecast of $127.7 million, the 2010 level of chargeback costs, for the Test Year.[1564]

SCE operates a vehicle and equipment fleet consisting of passenger cars, vans, pick-up trucks, forklifts, heavy-duty trucks with aerial equipment (buckets and cranes), loaders, tractors, stringing equipment, trailers, helicopters, and other vehicles. SCE's Transportation Services Department (TSD) provides fleet management/operational services (acquisition, maintenance, repairs and disposal), aircraft support of utility operations, crane operations, and other related transportation services.

TSD's costs are recorded to both the O&M FERC accounts and capital work orders for SCE's business units.[1565] TSD's costs are charged back to, and embedded within, the forecasts and testimony of the individual Business Units.[1566]

SCE says that the increase in fleet ownership is primarily associated with the leasing costs for vehicle replacements, vehicle additions and reductions, rental costs, licensing and other fees, and administrative costs.[1567] SCE says that its forecast of vehicle additions is primarily driven by workload changes due to infrastructure replacement and growth. SCE says it expects to add 163 vehicles in 2010, 280 in 2011, 139 in 2012.[1568] SCE also expects new costs in 2012

[1562] Ex. DRA-11, p. 31.

[1563] Ex. SCE-9, Vol. 2, pp. 150 and 151.

[1564] Ex. DRA-11, p. 32.

[1565] Ex. SCE-9, Vol. 2, p. 142.

[1566] Ex. SCE-9, Vol. 2, p. 150.

[1567] Ex. SCE-9, Vol. 2, p. 153.

[1568] Ex. SCE-9, Vol.2, p. 155.

of $900,000 for annual maintenance and reporting fees for its proposed vehicle onboard technology capital project.[1569]

DRA recommends using 2010 recorded expenses to forecast 2012 expenses. DRA recommends reductions to SCE's funding requests in the Transmission and Distribution Business Unit (TDBU) as discussed above in Section 5 of this Brief. If DRA's recommended reductions to TDBU are adopted, there will be a reduced need for vehicle additions and associated maintenance and fuel expenses in 2012.

DRA also disputes SCE's proposed vehicle onboard technology capital project as discussed below. If the Commission rejects funding for SCE's proposed vehicle Onboard Technology capital project, there will be no need for O&M expense for the associated maintenance and reporting fees in 2012.

11.4.2. Transportation Services Department – Capital Expenditures

SCE is requesting $10.600 million of capital expenditures in 2012 for an Onboard Technology project. DRA recommends zero ratepayer funding for this project.[1570]

SCE says that the technology is used by companies to improve their vehicle fleet management operations and asset utilization with Global Positioning System, and to obtain key vehicle-specific performance monitoring capabilities such as fuel consumed, miles driven, engine idle hours, over-speeding, hard-braking, etc.[1571]

DRA disputes the need for this $10.600 million of capital expenditures for the Onboard Technology project. In SCE's last GRC, SCE requested ratepayer funding for an Onboard Technology project using similar, if not identical arguments. In the last GRC, SCE asked for $3 million for the two projects. In this GRC, SCE is asking for $10.6 million.

The Commission authorized SCE the funding for the Onboard Technology project in the last GRC. SCE chose to spend the money elsewhere. Ratepayers should not be asked again to fund a project SCE itself decided it could do without. DRA, therefore, continues to recommend $0 ratepayer funding.

[1569] Ex. SCE-9, Vol. 2, p. 158.

[1570] Ex. DRA-11, p. 44.

[1571] Ex.SCE-9, Vol. 3, pp. 160 and 161.

11.5. Supplier Diversity

SCE's Supplier Diversity and Development department manages the procurement of materials/services and the warehousing/logistics organizations within the Supply Management division in the Operations Support Business Unit.

SCE must comply with the California Public Utilities Commission's General Order 156 ("GO 156") which was adopted in April 1988. GO 156 requires the California utilities to have programs in place to meet a minimum goal of 21.5%procurement with woman, minority and disabled veterans business enterprises (DBE).[1572]

11.5.1. FERC Accounts 920/ 921

For Supplier Diversity and Development FERC Accounts 920/ 921,[1573] SCE is requesting $3.3 million, a 123% increase over 2009 recorded expenses. DRA recommends a TY 2012 forecast of $1.955 million.

SCE used 2009 recorded expenses as the starting point to forecast TY 2012 expenses. SCE is requesting funding for ten additional staff to support Supplier Diversity and Development efforts at $1.073 million of labor.[1574] SCE is requesting an increase of $747,000 to support its SCE Supplier University program, Supplier Training Program, and Outreach programs.[1575]

DRA recommends using a five-year average, or $1.955 million, to forecast TY 2012 expenses for Supplier Diversity and Development.[1576] Over the five year period, the recorded expenses of SCE's Supplier Diversity and Development department have decreased from a high of $2.292 million in 2006, to a low of $1.480 million in 2009. From 2005 to 2010, SCE had a staff of six FTEs.[1577] SCE now seeks to augment that staff to a total of 18 FTEs in 2012. DRA disagrees with SCE's forecast for the following reasons.

First, SCE has been able to comply with G.O. 156 during the 2005 to 2009 period with the recorded expenses and staffing levels described above. Second, SCE was able to earn supplier diversity awards while operating at the 2005 to 2009 level of expenses. SCE states that

---

[1572] Ex. SCE-9, Vol. 2, p.129

[1573] Ex. DRA-11, p. 30.

[1574] Ex. SCE-9, Vol. 2, p. 136.

[1575] Ex. SCE-9, Vol. 2, p. 139.

[1576] Ex. DRA-11, p. 30.

[1577] Ex. DRA-11, p. 31.

it received the prestigious national award, Edison Electric Institute (EEI) Supplier Diversity Excellence Award, at the 27th Annual Supplier Diversity Conference, which was given in recognition of "SCE's over 20-year commitment to identify, mentor, and contract with DBEs."[1578] SCE also received several honors and awards recognizing the organization-wide commitment to supporting and developing diverse suppliers in 2009.[1579]

SCE has been able to meet or exceed Supplier Diversity requirements with a staff of six FTEs for the entire record period. SCE has not justified increasing the staff 225% at ratepayer expense.[1580]

11.6. Operations Support Services

Operations Support Services provides centralized support to the Organization's Senior Vice President, and the senior leadership of the six Operations Support Departments.[1581] For Operations Support Services, SCE is requesting $11.918 million for TY 2012 for FERC Accounts 920 and 921.[1582] DRA recommends $4.466 million in TY 2012.[1583]

The recorded expenses were at a low of $1.807 million in 2006 and increased significantly to $11.918 million in 2009. The recorded expenses then decreased to $8.458 million in 2010.[1584]

SCE says its recorded expenses increased approximately $10.1 million, or 560%,[1585] between 2006 and 2009 as a result of several actions:

- Further centralization of Operations Support's planning activities-specifically the transfer of personnel from other areas of the Business Unit to Operations Support Services;
- A change in accounting practice that resulted in Operations Support Services costs, previously charged back to other areas of Operations Support, being recorded as A&G; and

---

[1578] Ex. SCE-9, Vol. 2, p. 131.

[1579] Ex.SCE-9, Vol. 2, p. 131.

[1580] Ex. DRA-1, p. 31.

[1581] Ex. SCE-9, Vol. 2, p. 113.

[1582] Ex. SCE-9, Vol. 2, p. 114.

[1583] Ex. DRA-11, p. 27.

[1584] Ex. DRA-11, p. 27.

[1585] Ex. DRA-11, pp. 27-28.

- Additional hiring to allow Operations Support Services to keep pace with the growing Business Unit population.[1586]

DRA recommends using SCE's 2008 recorded expenses to forecast TY 2012 expenses. SCE says that the expense increases from 2006 to 2009 were the results of SCE centralization of Operations Support's planning activities, making a change in accounting practices, and additional hiring. SCE says that, in 2009, accounting changes were made, affecting 54 employees in Operations Support Services, for the purpose of consolidating the recorded labor for these individuals. SCE claims that consolidating recorded labor served to simplify monitoring and managing the budgets for these personnel.

While SCE may consider that its "centralization," and "changes in accounting practices," and the re-naming of various of its organizations served to simplify monitoring and managing the budgets for those personnel, these changes have only made tracking SCE's expenses more difficult. DRA was unable to find evidence in SCE's testimony that SCE had actually decreased the expenses for the other Business Unit FERC accounts in recorded costs, or in the TY 2012 forecast.[1587] If the other SCE Business Units did not remove costs that SCE has transferred to Operations Support Services, then the other SCE Business Units still have the expenses embedded in their recorded expenses. Since SCE used these 2005 to 2009 recorded expenses to forecast TY 2012 expenses, these other SCE Business Units will be overstating their expenses for the TY 2012 forecast.[1588]

DRA, therefore, asked SCE to provide documentation that would enable DRA to determine that SCE had, in fact, removed expenses from other Business Units when it increased the expenses to the Operations Support Services. SCE's response included an explanation of how the changes were supposedly made, and pages of tables, but nothing that would allow DRA to verify that reductions actually *had* been made. Obscuring matters still further, SCE also changed the names of the various departments[1589] since its last GRC, making tracking what was spent by which group even more difficult.

[1586] Ex. SCE-9, Vol. 2, p. 117.

[1587] Ex. DRA-11, p. 29.

[1588] Ex. DRA-11, p.29.

[1589] 19 RT 3130-3134, Hampton/ SCE.

In Rebuttal, SCE cited to the data request response it had provided DRA on the subject as proof that SCE had, in fact, shown that embedded costs were removed. Since the data request response is an exhibit in the record, the Commission can make its own determination of how useful that response is.[1590]

DRA, however, has not been able to verify that the increases in costs SCE added to Operations Support Services have actually been removed from other Business Units. DRA, therefore, recommends against using 2009 recorded expenses to forecast TY 2012 expenses for the FERC Accounts 920 and 921 of Operations Support Services. DRA continues to recommend that the Commission use 2008 recorded expenses to forecast TY 2012 expenses.[1591]

12. Ratemaking

Revenue Requirements are calculated by a computer model developed by SCE which is referred to as the Results of Operations (R/O) Model.[1592]

SCE added minor modifications to the R/O model SCE used in the 2009 General Rate Case (GRC). DRA performed limited testing of the R/O model SCE provided with its application on November 19, 2010, and found it to reflect the appropriate method of determining the Summary of Earnings. On April 20, 2011, SCE updated its R/O model to account for SCE's proposals for Bonus Depreciation resulting from the tax legislation enacted on December 17, 2010. DRA did not have the time to test this updated version before its testimony was due, but hopes to do so before the Update phase of the proceeding.

DRA used SCE's April 20, 2011 version of the R/O model to calculate the results of operation contained in its showing. The various DRA witnesses provided the input data for the R/O model, and discussions of the input data are contained in various DRA exhibits as described in this Brief. DRA made some minor modifications to the R/O model to accommodate some witnesses' requests so that the model can properly reflect their recommendations.

DRA also corrected an error SCE incorporated in its R/O model relating to the proper formula for calculating lead/ lag for Working Cash. This is discussed in more detail below in Section 20, Rate Base.

[1590] Ex. SCE-24, Vol. 3, p. A-55.

[1591] Ex. DRA-11, p.29.

[1592] Ex. DRA-2, p. 1.

13. Sales and Customers

13.1. Overview

SCE and DRA relied upon econometric models to forecast electric sales to the residential, commercial, industrial, other public authority, agricultural and street lighting classes of service. The econometric models rely upon historical monthly data to establish a statistical relationship between electric energy consumption and weather, average constant dollar electric rates, and economic conditions in SCE's service area.[1593] Under SCE's approach, historic electric consumption is defined to include electric sales plus electric conservation and economic bypass. To arrive at forecasted sales, forecasts of electric conservation and economic bypass are subtracted from forecasted electric consumption.[1594]

13.2. Economic / Demographic Conditions

An important factor explaining forecasted electric consumption is the growth in economic activity in SCE's service area. SCE relies upon ISI Global Insight (Global Insight) for its projections of economic conditions in its service area. SCE explains that: "Global Insight is forecasting a very slow recovery…The recession is projected to officially end in 2010, but economic activity is expected to be very modest in the next few years."[1595]

The UCLA Anderson Forecast for the Nation and California (UCLA) is similarly pessimistic. UCLA's December 2010 forecast concludes that: "In the last California Report we characterized the recovery in the near term as…indicating a period of almost imperceptible growth. The current forecast is for similar slow growth until the end of next year. With only the first indication of changes in consumer and business expectations revealing themselves in the contemporaneous data, and in the absence of an external driver to induce growth, this is the most likely scenario for this phase of the recovery."[1596]

The key macroeconomic drivers of SCE's residential, commercial, industrial, other public authority, and agricultural econometric models are real per capita personal income and

---

[1593] Constant dollar electric rates are defined as average nominal electric rates deflated by a price deflator.

[1594] Ex. DRA-3, p. 6.

[1595] Ex. SCE-10, Vol. I, p. 47.

[1596] Ex. DRA-12, p. 7 citng "The UCLA Anderson Forecast For The Nation and California," December 2010, p. 79.

employment.[1597] While SCE's personal income growth forecasts are slightly below UCLA's forecasts for the state, they are generally consistent with UCLA's projections. Since SCE's forecasts are generally consistent with UCLA's projections, DRA adopted SCE's real per capita income forecasts.[1598]

For the commercial sector, SCE's employment forecast is slightly more optimistic than UCLA's. In 2011 and 201, for example, SCE forecasts that commercial employment will rise by 3.79 and 3.14 percent, respectively. For the trade sector, UCLA forecasts statewide employment growth of 2.26 percent in 2011 and 3.96 percent in 2012.[1599]

SCE's industrial employment forecast is also slightly more optimistic than UCLA's statewide manufacturing employment forecast. UCLA projects that between 2010 and 2011 manufacturing employment will increase by less than one percent. Between 2011 and 2012 UCLA forecasts manufacturing employment growth of about two percent. In contrast, SCE forecasts industrial employment growth of 1.36 percent between 2010 and 2011 with a further increase of 2.57 percent between 2011 and 2012. The December UCLA is for slow employment growth through 2012. UCLA concludes that: "Our expectation for 2011 is a growth in employment of 1.6 %...Employment growth is expected to speed up in 2012..[With] …the unemployment rate…stuck between 12 % and 13 %...Employment growth will only push unemployment down marginally and we do not expect it to reach 9.9 % until the 4th quarter of 2012."[1600]

Forecasted electric sales are also impacted by electric rate assumptions. SCE says that: "[t]he average electric price in 2010 is expected to remain approximately equal to the 2009 level, but increase in 2011 due to higher fuel prices and expenditures associated with the 2012 GRC application…All other things equal, the impact of higher electric rates is a reduction in average electricity use per customer."[1601] In developing its forecasted electric sales, DRA relied upon SCE forecasted electric rate assumptions.[1602]

[1597] Ex. DRA-3, pp. 6-7.

[1598] Ex. DRA-3, p. 7.

[1599] Ex. DRA-3, p. 8.

[1600] Ex. DRA-3, p. 8, footnote 6.

[1601] Ex. SCE-10, Vol. 1, p. 47.

[1602] Ex. DRA-3, p. 9.

13.3. Sales

13.3.1. Residential Sales

SCE estimates residential econometric models for Los Angeles County, Orange County, Riverside County, San Bernardino County, Ventura/Santa Barbara Counties and Rural Counties. For each county area model, electric consumption per customer (electric sales plus conservation plus economic bypass) is modeled as a function of heating and cooling degree days, billing days, a linear time trend, constant dollar per capita personal income, constant dollar average electric rates, along with various monthly dummy variables. Heating and cooling degree days are multiplied by winter and summer season dummy variables and scaled by heating and cooling efficiency indexes.[1603] The linear time trend captures "the systematic long term trend growth that is not explained by other explicit variables in the econometric models."[1604] The real average price terms in the models are adjusted to reflect the impact of electric restructuring on residential electric consumption. This is accomplished by multiplying the average real residential price terms by dummy variables reflecting the historic periods when the Commission was restructuring the California electric energy industry.[1605] An average use functional form is used (electric consumption divided by electric customers) and the models are estimated with monthly observations over the period January 2001 through February 2002.[1606]

DRA evaluated SCE's residential econometric models by first replicating their results.[1607] This is standard practice in empirical economics. DRA then estimated alternative versions of SCE's residential models. Specifically, DRA regressed the log of residential energy consumption (electric sales plus conservation and economic bypass) on cooling and heating degree days, the

---

[1603] SCE defines the summer season to include the months of April through October. For these months the summer season dummy takes on the value one and zero in the remaining months. The winter season includes the months of November through March. For these months the winter dummy variable takes on the value one and zero in the remaining months.

[1604] Ex. DRA-3, p. 10, citing SCE response to DRA data request DRA_006_TMR, Q/A 1.

[1605] As a result, there are two price terms in the residential models. The two price terms are derived by multiplying the real average electric rates by dummy variables representing the restructuring and non-restructuring periods. The electric restructuring period includes the months of February 2001 through January 2002 and the non-restructuring period includes the remaining months.

[1606] Specifically, the models for Los Angeles County, Orange County, and Riverside County were estimated from January 2001 through February 2002. The remaining models were estimated over the period from June 2001 through February 2002.

[1607] DRA relied upon the Time Series Processor (TSP) econometric software package while SCE relied upon the E-Views econometric software package.

log of billing days, the log of real personal per capita income, the log of real average electric rates, a linear time trend, along with a set of monthly binary variables. Following SCE, DRA adjusted the real average price terms in its alternative models to capture the impact of electric restructuring on residential electric consumption. For each county, DRA's residential forecasts are within one percent of SCE's forecasts.

DRA and SCE are forecasting declines in residential sales over the 2010-2012 forecast period. SCE projects that total residential sales will decline from 30,063 GWH in 2009 to 28,666 GWH in 2012. This is an annual average decline of 1.35 percent per year from 2009 recorded levels. DRA's forecasted decline in residential sales is similar, with DRA forecasting that residential sales will decline to 28,843 GWH in 2012. DRA's and SCE's residential demand forecast is consistent with the recent decline in residential sales.

DRA's and SCE's residential forecast is slightly below the long term trend growth in residential sales. Over the period 2000 through 2009 residential sales grew, on average, by 1.51 percent. It should be noted, however, that historic residential sales are characterized by large year to year fluctuations. Between 2000 and 2001, for example, residential sales decline by 6.74 percent. Between 2005 and 2006, residential sales rose by 4.52 percent. More recently, residential sales declined sharply. Between 2008 and 2009 residential sales declined by 2.22 percent.[1608]

13.3.2. Commercial Sales

SCE models commercial electric consumption as a function of efficiency adjusted cooling degree days, commercial employment, real average commercial gas rates, billing days, a linear time trend along with a series of monthly dummy variables. Similar to the residential models the real average price terms in the model are adjusted to reflect the impact of electric restructuring on commercial employment construction. An average use functional form is used and the model is estimated with monthly observations over the period March 2003 through February 2010.

DRA's commercial model is similar to SCE's. In contrast to SCE, however, DRA regressed the log of commercial consumption on efficiency adjusted cooling degree days, the log of commercial employment, the log of real average electric rates, a linear time trend and a series

[1608] Ex. DRA-3, p. 13.

of monthly binary variables. As did SCE, DRA adjusted the real average price terms in its model to reflect the impact of electric restructuring on historic commercial electric consumption. DRA estimated its model with monthly observations over the period March 1993 through February 2010.

DRA and SCE arrive at very similar forecast results. For 2010, 2011, and test year 2012, DRA's commercial forecast differs from SCE's by less than one percent. DRA and SCE are projecting increases in commercial sales over the 2010-2012 forecast horizon. SCE forecasts commercial sales to rise from its 2009 recorded level of 41,819 GWH to 41,819 GWH in 2012. This is an annual average increase of 2.70 percent. DRA forecasts that commercial sales will increase to 42,224 GWH. This is a slightly higher annual average growth rate of 3.30 percent.

The DRA and SCE commercial forecasts are consistent with the long-run growth in commercial sales. Over the period 1993 through 2008, commercial sales grew, on average, by 2.59 percent per year.[1609] Over the period 2000 – 2009 commercial sales grew, on average, by two percent per year. As a result of the recent recession, commercial sales declined by 4.53 percent between 2008 and 2009.

13.3.3. Industrial Sales

SCE models industrial sales as a function of efficiency adjusted cooling degree days, real average electric rates, manufacturing employment, billing days, a linear time trend, and a series of monthly dummy variables. Following the approach used in the residential, and commercial models, the price terms in the model are adjusted to reflect the impact of electric restructuring on historic industrial electric consumption. SCE relies upon an average use functional form and the model is estimated with monthly observations over the period January 1995 through February 2010.

DRA's industrial econometric model is similar to SCE's. DRA regressed the log of industrial electric consumption on efficiency adjusted cooling degree days, the log of billing days, the log of manufacturing employment, the log of real average industrial electric rates, a linear time trend, and a series of monthly dummy variables. Following SCE, DRA adjusted the real average electric rates to capture the impact of electric restructuring on historic electric

[1609] The SCE and DRA commercial econometric models were estimated over this time period.

industrial consumption. DRA estimated its industrial econometric model with monthly observations over the period January 1995 through February 2010.

DRA forecasts slightly lower industrial sales than does SCE. For the 2010 – 2012 forecast period DRA's industrial forecasts are approximately between one and two percent below SCE's forecast. DRA and SCE are projecting declines in industrial sales into the forecast period. SCE projects that industrial sales will decline, on average, by 1.18 percent. DRA's forecasted decline is similar, projecting that industrial sales will decline, on average, by 1.56 percent over the forecast period. Both the DRA and SCE forecasts are consistent with the historic decline in industrial sales. For example, over the period 1995 through 2009 industrial sales declined, on average, by 3 percent per year. Over the more recent period, the decline was even sharper. Between 2007 and 2008 industrial sales declined by 4.84 percent. This was followed by a 2.73 percent decline between 2008 and 2007. The largest historic decline in industrial sales occurred between 2008 and 2009 when industrial sales declined by nearly 12 percent.

13.3.4. Other Public Authority Sales

SCE models Other Public Authority electric consumption as a function of energy efficiency adjusted cooling degree days, real average electric rates lagged one month, government employment, billing days, a dummy variable capturing military base closings, a linear time trend along with a series of monthly binary variables. An average use functional form is used and the model is estimated with monthly observations over the period January 1993 through February 2010.

DRA's model is similar. DRA regressed the log of Other Public Authority electric consumption on efficiency adjusted cooling degree days, the log of real average electric rate lagged one month, the log of government employment, the log of billing days, a linear time trend, a dummy variable representing military base closings, along with additional monthly binary variables.

As in the case of the other classes of service, DRA and SCE arrive at virtually identical Other Public Authority forecasts. For the entire 2010 – 2012 forecast period the DRA and SCE Other Public Authority sales forecasts differ by less than one percent.

Both DRA and SCE are projecting declines in Other Public Authority sales. SCE forecasts that Other Public Authority sales will decline from 5,209 MWH in 2009 to 5,180 GWH in test year 2012. This is an annual average decline of 0.15 percent over the forecast period.

DRA forecasts an annual average percent decline in Other Public Authority sales of a similar magnitude, 0.21 percent. The DRA and SCE forecasts are consistent with long-run decline in Other Public Authority sales. Over the period 1993 through 2009, Other Public Authority sales declined, on average, by 0.45 percent per year. Over the more recent 2000-2009 period, Other Public Authority sales declined on average by 1.41 percent per year.[1610]

13.3.5. Agricultural Sales

For the agricultural sector, SCE models agricultural consumption per customer as a function of real average agricultural electric rates, agricultural employment per capita, a variable capturing water runoff from the San Joaquin River, billing days, a linear time trend, along with several monthly binary variables. The model is estimated with monthly observations over the period January 1995 through February 2010.

Similar to its other econometric forecasting models, DRA's agricultural model is based on a log-log functional form. DRA regressed the log of agricultural electric consumption on the log of billing days, the log of agricultural employment, the log of real average electric rates, logged values of the San Joaquin river runoff, a linear time trend, along with a series of monthly dummy variables. DRA estimated its model over the period February 1995 through February 2010.

For the forecast period the DRA and SCE agricultural sales forecasts are virtually identical. For 2011 and 2012, the DRA and SCE forecasts differ by less than one percent. SCE and DRA are both forecasting declines in agricultural sales. SCE forecasts that agricultural sales will decline from 1,432 GWH in 2009 to 1,368 GWH in 2012. This is an annual average decline of 1.39 percent. DRA's test year forecast of 1,376 GWH is an annual average decline of 1.21 percent from 2009 recorded levels. The DRA and SCE forecasts are consistent with the recent trend in agricultural sales growth. Over the period 2007 through 2009, agricultural sales grew, on average, by less than one percent per year.[1611]

[1610] Ex. DRA-3, p. 15.

[1611] Ex. DRA-3, p. 16.

13.4. Customer Growth Rates

13.4.1. Residential Customers

SCE forecasts residential customers as a function of new building permits and vacancy rates. As SCE explains: "The forecast of residential customer additions in multiple steps for each county within the SCE service area. The primary steps are: (1) forecasting residential building permits, (2) lagging the building permits for construction time to calculate new residential units, (3) converting residential units to active residential customers based on assumptions about future residential vacancy rates."[1612] Following the approach used to forecast residential sales, SCE presents forecasts of residential customers for Los Angeles county, Orange county, San Bernadino county, Ventura/Santa Barbara counties, and the rural counties, (Inyo, Kern, Kings, and Mono counties.) Total residential customers are the sum of the county level forecasts. Over the 2010 – 2012 forecast period SCE is projecting that total residential customers will grow by less than one percent per year.

DRA relied upon SCE's residential customer forecasting methodology but updated SCE's building permit forecast with information taken from the December 2010 UCLA forecast. To arrive at an alternative building permit forecast based on the December UCLA report DRA applied SCE's county percent distribution of building permits to the UCLA forecast of total building permits for the state of California. For example, in 2010 SCE's percentage of building permits for Los Angeles County equaled 49 percent of their forecast of total building permits. To arrive at a forecast of building permits for Los Angeles County in 2010, DRA applied this percentage to the 2010 UCLA forecast of statewide building permits. A similar procedure was used to arrive at forecasted building permits for 2011 and 2012 for each of the counties in SCE's service area.

DRA's use of the December 2010 UCLA forecast results in slightly higher residential customer growth rates. For example, for 2011 and 2012 DRA forecasts total residential customer growth rates of 0.68 and 0.96 percent, respectively. SCE, on the other hand, forecasts total residential customer growth rates of 0.57 percent for 2011 and 0.69 percent for test year 2012. Both the DRA and SCE residential customer forecasts are slightly below the long run growth in residential customers. Over the period 1998 through 2009 total residential customers grew, on average, by one percent. However, since 1997 there has been a marked decline in

[1612] Ex. DRA-3, p. 17, footnote 14..

residential customer growth. Between 2007 and 2009 total residential customers grew by less than one percent in each year.

When DRA submitted its testimony in May 2011, the UCLA forecast of total statewide building permits was 82,500 for 2011, and 148,500 for 2012.[1613] In June 2011, UCLA issued a revised forecast of building permits. According to this most recent report, UCLA forecasts 46,400 building permits statewide in 2011, and 59,200 in 2012.[1614] According to the June 2011 UCLA report, the reason for the forecast decline is that:

> ...the economy is still slowing and we haven't come out of the recession yet. And it is being reflected, the load growth is being reflected in the building permit numbers. And, more specifically, the housing market hasn't fully recovered.[1615]

If DRA had had the June 2011 forecast when it prepared its testimony, DRA's residential customer forecast probably would have been lower.[1616]

13.4.2. Commercial Customers

SCE models commercial customers as a function of lagged values of commercial customers, lagged values of residential customers, a linear time trend and series of monthly dummy variables. Specifically, the first difference of commercial customers is regressed on lagged values of the first difference of commercial customers and lagged values of the first difference of residential customers.[1617] The model is estimated over the period March 1991 through January 2010.[1618]

DRA's commercial customer model is also based on first differences. DRA regressed the first difference of commercial customers on the first difference of commercial employment, the

---

[1613] 21 RT 3571, Renaghan/ DRA.

[1614] 21 RT 3574, Renaghan/ DRA.

[1615] 21 RT 3575, Renaghan/ DRA.

[1616] 21 RT 3576, Renaghan/ DRA.

[1617] The first difference is defined as the difference between the current value of a series less the value of the series in the previous period. SCE also imposes a polynomial distributed lag (PDL) on past values of residential customers. A PDL is an econometric technique which forces the coefficients of the variable to lay along a polynomial of a certain degree and a pre-imposed lag structure. For the commercial customer model SCE uses a lag length of 10 months and a polynomial of degree one for the first difference of residential customers. (Ex. DRA-3, p. 18, footnote 15.)

[1618] The period January 1998 through December 2000 is excluded from the estimation period.

first difference of residential customers, a linear time trend, and a series of monthly dummy variables. DRA's model is estimated over the period February 1993 through January 2010.[1619]

The DRA and SCE commercial customer models yield virtually identical forecast results. Over the 2010 – 2012 forecast period the SCE and DRA commercial forecasts differ by less than one percent. Both the DRA and SCE forecasts are consistent with the recent growth in commercial customers. Over the forecast period SCE is projecting that commercial customers will grow, on average, by 0.94 percent per year. DRA forecasts that commercial customers will grow, on average, by one percent per year. While over the period 2000 – 2009 commercial customer growth has averaged 2.54 percent per year, recently the rate of growth of commercial customers has declined sharply. Between 2007 and 2009 commercial customers grew, on average, by less than one percent. The DRA and SCE forecasts represent a continuation of this recent slow growth in commercial customers.

13.4.3. Industrial Customers

SCE models the first difference of industrial customers as a function of lagged values of the first difference of industrial customers, lagged values of the first differences of manufacturing employment and a series of monthly binary variables.[1620] The model is estimated with monthly observations over the period January 1994 through February 2010.

DRA's industrial customer model is very similar to SCE's. SCE regressed the first difference of industrial customers on lagged values of the first difference of manufacturing employment along with a series of monthly dummy variables.[1621]

DRA and SCE arrive at virtually identical industrial customer forecasts. Over the forecast period, DRA's and SCE's industrial customer forecasts differ by less than one percent. Both DRA and SCE project declines in industrial customer growth. Over the forecast period SCE estimate that, on average, industrial customers will decline by 2.35 percent while DRA estimates that industrial customers will decline by approximately the same amount. Over the period 1994 through 2009 SCE's industrial customers have declined, on average, by 5.63 percent

---

[1619] Following SCE, DRA also excluded the period January 1998 through December 2000 from the estimation period.

[1620] The first difference of manufacturing employment is modeled as a six month PDL of degree one. (Ex. DRA-3, p. 19, footnote 18.)

[1621] While SCE used a six month PDL on the first difference of manufacturing employment, DRA's PDL on the first difference of manufacturing employment was only four quarters.

per year. In fact in every year of the 2001 – 2009 period, industrial customers declined. This decline in industrial customer growth is consistent with the long run migration of industrial manufacturing away from California.

13.4.4. Other Public Authority

SCE also relies on a first difference model to forecast OPA customers. Specifically, the first difference of Other Public Authority customers is regressed on lagged values of Other Public Authority customers, monthly dummy variables, and lagged values of the first difference of Other Public Authority floorspace.[1622] The model is estimated over the period March of 2001 through February 2010.

DRA's model is similar. DRA regressed the first difference of OPA customers on lagged values of the first difference of OPA customers, lagged values of the first difference of Other Public Utility floorspace, and a series of monthly dummy variables.[1623] DRA's model was also estimated over the period March 2001 through February 2010.

For the forecast period DRA's and SCE's forecasts are virtually identical. Both DRA and SCE are projecting Other Public Authority customers to decline throughout the forecast period. SCE projects that Other Public Authority customers will decline, on average, by 1.46 percent. This decline is consistent with the historic long run decline in Other Public Authority customers. Over the period 1993 through 2009 Other Public Authority customers declined, on average, by 1.31 percent per year. Similar, to the trend in industrial customers, Other Public Authority customers declined in every year of the historic period.

13.4.5. Agricultural Customers

A first difference model is also used to forecast agricultural customers. Specifically, SCE regresses the first difference of agricultural customers on the first difference of agricultural customers lagged one month, the first difference of agricultural employment, a linear time trend, along with a series of monthly dummy variables. The model is estimated from June 1993 through February 2010.

SCE forecasts virtually no growth in agricultural customers into the forecast period. This is consistent with the historic pattern of agricultural customer growth. Over the period 1993

[1622] A six month lag is imposed on the PDL for the first difference of OPA floorspace.

[1623] DRA imposed a four month lag on the PDL for the first difference of OPA floorspace.

through 2009 agricultural customers declined, on average, by .80 percent per year. Similarly, over the shorter 2000 – 2009 period, the pattern of growth was the same, with agricultural customers declining by less than one percent per year.[1624]

13.5. New Meter Connections

13.5.1. Residential

SCE forecasts residential meter connections as a function of building permits and a series of monthly dummy variables. Building permits are modeled as a second degree 12 month PDL. The model is estimated with monthly observations over the period January 1998 through December 2009.

DRA's model is similar. DRA utilized a log-log model to forecast residential new meter connections. DRA regressed the log of new residential meters on the log of residential building permits along with a series of monthly dummy variables. DRA modeled building permits as a 16 month second degree polynomial. This model was estimated over the period February 1988 through December 2009.

DRA's model produced a forecast similar to SCE's. For example, in 2010, 2011, and test year 2012, SCE forecasts new gross residential meter connections of 22,324, 28,215, and 38,591, respectively. DRA forecast gross new residential meter connections of 21,082 in 2010, 27,560 in 2011, and 38,757 in test year 2012.[1625] Based on the information available to DRA at the time it submitted its testimony, DRA projected sharp increases in new residential meter connections into the forecast period.

13.5.2. Non-Residential

SCE models non-residential customers as a function of residential meters lagged three months and commercial meters lagged one month. The model is estimated over the period from the first quarter of 1998 through the fourth quarter of 2009. DRA reviewed the model results and considers them reasonable.

SCE forecasts declines in non-residential meter connections in 2010 and 2011 and an increase in non-residential meters in test year 2012. Specifically, non-residential meter connections are forecast to decline from 8,078 in 2009 to 7,115 in 2010, with a further decline to

---

[1624] Ex. DRA-3, p. 21.

[1625] Ex. DRA-3, p. 21.

6,953 into 2011. In test year 2012 SCE is forecasting an increase in non-residential meter connections to 7,443. This is still below the level achieved in 2009.[1626] Based on the information available to DRA at the time it submitted its testimony, DRA considered SCE's non-residential meter forecast to be reasonable.

14. Cost Escalation

For this GRC, SCE and DRA historic and forecast escalation on information taken directly from Global Insight's Power Planner. In recent GRCs, DRA and other major energy utilities in California, SCE, Pacific Gas and Electric (PG&E), and the Sempra Utilities, San Diego Gas & Electric (SDG&E), and the Southern California Gas Company (SoCalGas), have based their labor and non-labor cost escalation estimates on information taken from the Global Insight Power Planner. DRA recommends that the labor and non-labor escalation rates be revised, as needed, during the Update phase in accordance with the General Rate Case plan.[1627]

14.1. SCE Methodology

For the historic period 2005 through 2009, SCE proxies labor cost increases by developing estimates of average hourly earnings (AHE) by functional category, i.e., Steam Production, Nuclear Production, Hydro Production, Other Production, Transmission, Distribution, Customer Accounts, Customer Service & Information, and Administrative & General. Average hourly earnings are defined as total wages and salaries (straight time, overtime, and double time) divided by effective hours worked. "[E]ffective hours worked are calculated as the sum of: (i) straight time hours, (ii) overtime hours multiplied by one and one-half and double time hours multiplied by two."[1628]

For the forecast period 2010-2012 overall labor escalation is a weighted average of wage increases to the clerical/physical, executive/manager/supervisory, and professional/technical employee classifications. SCE says that: "The weighting was based on the shares of represented and non-represented employee wages and wages paid (for 2003-2006)."[1629]

[1626] Ex. DRA-3, p. 22.

[1627] Ex. DRA-4, p. 3.

[1628] Ex. SCE-10, Vol. I, p. 64.

[1629] Ex. SCE-10, Vol. 1, p. 64.

For part of the forecast period wage increases are known with certainty. For example, in 2010 and 2011 represented (union employees) are scheduled to wage increases of 4 percent in each year. In 2010, non-represented employees will receive, on average, a 3 percent wage increase. For 2010 this results in a weighted wage increase of 3.30 percent. Or, a labor escalation rate of 3.30 percent.

For 2011 and test year 2012, SCE proxies wage increases with indexes taken from the Global Insight Power Planner. Wage increases for Clerical and Physical workers are proxied by the index CEU442211008, Electric Generation, Transmission, and Distribution workers to these classifications. Executive, Manager and Supervisor wage increases are proxied with ECIWSPWMGRNS, Employment Cost Index-Managers and Administrators. Wage increases for Professional and Technical workers are linked to ECIWSPWP&TNS- Employment Cost Index Professional and Technical workers. These wage increases are then weighted by the relative shares of wages and salaries paid per labor proxy indexes and the relative weights associated with each index.

For 2011 and 2012, SCE's method results in weighted average labor escalation rates of 2.76 percent and 2.27 percent, respectively. SCE then applies these labor escalation rates for the entire 2010-2012 forecast to each functional category.

14.2. DRA's Methodology

DRA concurs with, or does not contest, SCE's labor and non-labor cost escalation methodologies in all but one area. For 2010 and 2011 DRA does **not** rely upon the 4 percent union wage increase. Rather, DRA relied upon the most recent (fourth quarter 2010) Global Insight Power Planner forecasts for the index CEU442211008 for clerical and physical wage increases.

SCE's negotiated 4 percent union wage increase for 2010 and 2011 is considerably higher than Global Insight's forecasted wage increases for similarly situated workers. For Electric Power, Generation, Transmission, and Distribution workers Global Insight forecasts wage increases of 2.30 percent in 2010 and 3.10 percent in 2011. Global Insight also projects moderate wage increases for All Utility Service workers. For this category of utility workers, Global Insight forecasts wage increases of 2.50 percent in 2010 and 1.70 percent in 2011.[1630]

[1630] Global Insight, Power Planner, Fourth Quarter 2010, Table A-30, Utility Price and Wage Indicators, p. 54

March 2011 data from the Bureau of Labor Statistics (BLS) also shows that California is experiencing relatively modest wage growth. For the third quarter of 2010 the BLS reports that the counties of Los Angeles, Riverside, Santa Barbara and Ventura are experiencing modest increases in average weekly wages. Los Angeles County, for example, had an increase of 3.1 percent in average weekly wages, for Riverside County the increase was 1.3 percent, San Bernardino County experienced an average weekly wage increase of 1.3 percent, in Ventura County the increase was 2.7 percent, while Santa Barbara County experienced an average weekly wage increase of 4 percent. For Los Angeles County, the Trade, Transportation, and Utilities sector experienced an average weekly wage increase of 2.9 percent.[1631]

In Rebuttal, SCE argues that "DRA did concede that this is the first time it has contested a collective bargaining agreement in a utility [rate] case."[1632] In support of this statement, SCE provides part of an answer DRA gave to a data request. In fact, DRA does *not* contest the validity of SCE's collective bargaining agreements. As DRA noted in the data request response which SCE paraphrased:

> This is the first time that DRA has critically evaluated the negotiated wage increases between the utilities and their unions. DRA is not challenging SCE's right to establish what it deems to be appropriate compensation for its employees. DRA is, however, arguing that ratepayers should not be responsible for wage increases which are substantially above the Global Insight forecasts for similarly situated workers.[1633]

In its cross examination of DRA witness, Dr. Thomas Renaghan, SCE attempts to justify the 4.0 percent wage increases granted its unionized workers for 2010 and 2011 on the grounds that the demand for labor inputs is increasing. SCE's own evidence shows that this is not the case. SCE's own cross-examination documents,[1634] contained a reference to a spreadsheet constructed by the Bureau of Labor Statistics which showed that the demand for electric power generation, transmission, and distribution workers was expected to decline by 9.8 percent over

---

[1631] Bureau of Labor Statistics, United States Department of Labor, County Employment and Wages, Third Quarter 2010, Technical Notes, Table 2, News Release, March 29, 2011.

[1632] Ex. SCE-25, Vol. 1, p. 23.

[1633] See Ex. SCE-25, Vol. 1, Appendix p. C-4, DRA Response to SCE-DRA-TMR-031Q/A 2.

[1634] Ex. SCE-72 and 73.

the 2008 – 2018 period.[1635] While this is national data, SCE provided little or no evidence that its demand for labor should be so large as to offset this national trend. SCE could only argue that if all its requests for increased capital spending were granted by this Commission it would result in some increase in the demand for labor. DRA witness Dr. Thomas Renaghan pointed out, however, that if all SCE's capital project requests were approved it would also result in an increase in the demand for capital and O&M inputs as well.[1636] SCE's weak evidence for an increase in the demand for labor coupled with the high unemployment rates in SCE's service area, documented by DRA in its testimony, call into question the validity of SCE's argument that its ratepayers should fund inflated wage increases for SCE's unionized workforce.

DRA continues to recommend that the Commission replace the union negotiated wage increase with the Global Insight Power Planner forecast for union wage increases and use the more recent Power Planner forecast. This results in lower labor escalation rates. For 2010, 2011, and 2012, DRA recommends the Commission adopt forecast labor escalation rates of 2.80 percent, 2.49 percent, and 2.22 percent.[1637]

15. Other Operating Revenue

DRA's specific recommendations relating to Other Operating Revenue are set forth in the sections where those revenues are expected to occur.

16. Post Test Year Ratemaking

16.1. Overview

The post test year 2013 and 2014 figures identified and discussed below are those appearing in DRA's testimony served on May 11, 2011, and do not reflect any of SCE's or DRA's changes or errata.

SCE seeks Commission authorization for an attrition mechanism which would yield estimated General Rate Case (GRC) revenue increases totaling $598 million[1638] (or 9.5%) in 2013 and $612 million (or 8.9%) in 2014, or revenue requirement levels of $6.884 billion in

---

[1635] 21 RT 3579, Renaghan/DRA

[1636] 21 RT 3566, Renaghan/DRA

[1637] Ex. DRA-4, p. 7.

[1638] The $598 million comprises $251 million in revenues for SmartConnect and $347 million for revenues associated with SCE's forecasted increases in expenses and/or capital additions. (Ex. DRA-21, p. 1, footnote 1.)

2013 and $7.496 billion in 2014. In contrast, DRA proposes net increases of $219 million (or 4.0%) in 2013 and $119 million (or 2.1%) in 2014.

Before 1982, the base revenue requirement was generally adjusted only during General Rate Case proceedings. In the period between GRC proceedings, base rates would not change, but the utilities received additional income from customer growth.

Post Test Year, or attrition, rate adjustments were implemented in the early 1980's primarily because of the unprecedented high inflation and lower rates of customer growth and sales in the late 1970's and early 1980's. Since the mid-1980's, inflation has generally declined to more modest historical levels. The utilities have also had various forms of revenue balancing account protection from sales fluctuation. Additionally, utility fuel-related costs that had high volatility, and over which utilities have limited control, were removed from base rates and are now recovered through separate mechanisms with balancing accounts.

The GRC proceeding is used to periodically review and set reasonable rates for utilities for a specific test year, in this case, 2012. For the period between GRC proceedings, the Commission has, in some cases, granted attrition-type increases and, in other cases, has not provided such increases. In the past, the Commission has stated:

> The attrition mechanism is not an entitlement. Nor is it a method of insulating the company from the economic pressures which all business experience…Neither the Constitution nor case law has ever required automatic rate increases between general rate case applications.[1639]

It is clear that utilities are not automatically entitled to attrition rate increases between rate cases, even though the Commission has included provisions for Post Test Year rate relief in some GRC decisions.

16.2. SCE's Post Test Year Ratemaking Proposals

Given SCE's PTYR proposals, SCE estimates attrition revenue increases totaling $598 million in 2013 and $612 million in 2014. The estimated $598 million revenue increase in 2013 represents a 9.5% increase relative to SCE's 2012 revenue requirement request, and the $612 million revenue increase in 2014 represents an 8.9% increase relative to SCE's forecasted 2013 revenue requirement.

[1639] 52 CPUC 2d 471, D.93-12-043

SCE's proposals yield post test year revenue requirement levels of $6.884 billion in 2013 and $7.496 billion in 2014.

16.2.1. SCE's Proposed Revenue Increases for Expenses, Capital Expenditures and Nuclear Refueling

16.2.1.1. Annual Advice Letters

SCE proposes to file attrition adjustment requests for 2013 and 2014 by advice letter. According to SCE, it will "…file an annual PTYR mechanism advice letter by November 1 of 2012 and 2013 for the following year, consistent with current procedure. This advice letter will specify the revenue requirement adjustment for O&M escalation, changes in capital-related costs, and the expected number of nuclear refueling outages and related costs."[1640]

16.2.1.2. O&M Expense Escalation

For the 2013 and 2014 post test years, SCE wants the Commission to adopt a methodology that is essentially similar to the one SCE requests for determining Test Year 2012 escalation rates for labor and non-labor O&M expense. SCE proposes the following:[1641]

- Using the latest Global Insight "Control" projections of escalation rates available on October 1 of the year in which the PTYR advice letters filings are made.
- Using the latest available escalation rates, but previous forecast errors would not be recovered or refunded.[1642]
- Incorporating actual union wage increases and target wage increases for nonrepresented employees into the 2013 and 2014 PTYR advice letters should such increases be granted[1643] prior to the adoption of a Phase 1 decision of the GRC.
- Using a 10.0% escalation rate in 2013 and 2014 for SCE's medical program costs and Post Retirement Benefits Other than Pensions (PBOPs), and using

[1640] Ex. SCE-10, Vol. 1, p. 98, lines 18-21.

[1641] Ex. SCE-10, Vol. 1, pp. 98-100.

[1642] This means using actual escalation factors for 2012 when they are known, and using the most current forecasted escalation rates available for 2013 and 2014. If the actual escalation rate for 2012 is lower than forecast, SCE would not refund the difference to ratepayers. If the actual escalation rate for 2012 is higher than forecast, SCE would not recover the difference from ratepayers. This is consistent with the approach generally used for post test year ratemaking.

[1643] The word "granted" means wage increases agreed to or authorized by SCE during the course of negotiating union contracts or determining compensation for nonrepresented employees. According to SCE, this proposal is consistent with the PTYR mechanisms adopted in the utility's 2006 and 2009 GRCs. (SCE email to DRA on January 13, 2011, at 4:33pm. See Ex. DRA-21, p. 8, footnote 9.)

A&G labor and non-labor escalation rates for other benefit costs (e.g., dental and vision plans, disability programs, group life insurance, etc.).

16.2.1.3. Capital-Related Cost Increases

SCE's proposed attrition mechanism includes capital additions associated with a budget-based forecast of capital expenditures, totaling approximately $4.7 billion in 2013 and $4.1 billion in 2014.[1644]

SCE also proposes that "…the associated revenue requirements be subject to refund if our capital spending budgets are not fully implemented."[1645] Specifically, SCE proposes to create a one-way balancing account that refunds any over-estimate of the revenue requirement associated with its forecasted 2013 and 2014 capital additions, including the cost of removal; the balancing account calculations would be cumulative over the combined 2-year period. This is similar to the method adopted in D.04-07-022 for SCE's 2003 GRC.[1646]

16.2.1.4. SmartConnect

SCE anticipates that full deployment of the Edison SmartConnect Program will be achieved by the end of 2012. SCE forecasts that the revenue requirement associated with full deployment of SmartConnect will be $251.3 million beginning in 2013.[1647]

However, should a delay occur and deployment continue into 2013, SCE proposes filing advice letters to modify the 2013 revenue requirement as needed, to more accurately reflect the Customer Service Business Unit (CSBU) revenues associated with "business as usual" versus full deployment.[1648]

16.2.1.5. Nuclear Refueling Outages

SCE anticipates two refueling outages at SONGS during the post test year period—one in 2013 and one in 2014—at a cost of approximately $46 million per refueling (in 2009 dollars), with SCE's share being about $36 million each.[1649]

[1644] Ex. DRA-21, p. 8, Table 21-3.

[1645] Ex. SCE-10, Vol. 1, p. 101, lines 1-2.

[1646] Ex. SCE-10, Vol. 1, p. 101, footnote 66.

[1647] Ex. SCE-10, Vol. 1, p. 11, Table III-5, line 3, "2013" column.

[1648] Ex. SCE-10, Vol. 1, pp. 28-29.

[1649] Ex. SCE-10, Vol. 1, p. 101, lines 14-15.

In SCE's 2012 and 2013 PTYR advice letters (filed by November 1 to establish the revenue requirement for 2013 and 2014), SCE will project the number of nuclear refueling outages for the following year. According to SCE, its Base Revenue Requirement Balancing Account (BRRBA) includes a flexible outage schedule mechanism to recover refueling outage costs. SCE proposes that this be continued to match refueling outage costs with revenue recovery.[1650]

16.2.1.6. Treatment of Major Exogenous Cost Changes

SCE's current PTYR mechanism allows the utility to seek recovery of costs associated with exogenous events (Z-Factors) that result in a major cost impact for SCE. SCE indicates that it is "…at risk for events which do not have a financial impact of more than $10 million. In addition, there is a $10 million 'deductible amount' applied on a one-time basis to the first year's revenue requirement associated with any approved Z-Factors. Costs associated with two named contingencies, new municipal utility formation and P.U. Code Section 463 projects, are treated as Z-Factors but without the $10 million threshold or the $10 million deductible."[1651] SCE also says that although neither SCE or DRA "…have identified any proposed Z-Factors since SCE's 2003 GRC was decided, the Z-Factor mechanism has nonetheless provided the assurance that a clear process is in place to deal with unanticipated major variations in SCE's costs."[1652]

SCE proposes that the existing Z-Factor mechanism be continued in this rate case.

16.2.2. SCE's Other Post-Test Year Ratemaking Requests

16.2.2.1. Application Requirement for Post-Test Year Ratemaking

In D.04-07-022, the Commission concluded that if SCE's attrition revenue requirement increase exceeded $150 million in either year, SCE would be required to submit an application, rather than an advice letter, for that year.[1653]

SCE requests that the Commission not require SCE to submit another application in 2012 or 2013 to reapprove its proposed PTYR mechanism.

[1650] Ex. SCE-10, Vol. 1, p. 101, lines 17-20 through p. 102, lines 1-3.

[1651] Ex. SCE-10, Vol. 1, p. 102, lines 8-13.

[1652] Ex. SCE-10, Vol. 1, p. 102, lines 15-17.

[1653] Ex. SCE-10, Vol. 1, p. 102, lines 20-24.

16.2.2.2. SCE's Claim of Error Regarding Construction Work in Progress in the TY 2009 Decision

SCE asserts that "…[t]he Commission's final decision in SCE's 2009 GRC contained a methodological error that forced SCE to temporarily restrain capital investment in late 2008 and 2009 to levels below the authorized amounts, in order to ensure that recorded costs did not exceed authorized revenues in 2010 and 2011. This methodological error by the Commission, in which it overlooked SCE's year-end 2008 balance of Construction Work in Progress (CWIP), meant that SCE could not spend at the levels ostensibly authorized for 2009, but we were able to do so over the cumulative three-year cycle (2009-2011)."[1654]

SCE devotes another four-and-a-half pages of testimony criticizing the Commission's decision in the 2009 GRC until it finally proposes that, in this GRC, the Commission should adopt the same capital-related PTYR mechanism that was adopted in the 2003 GRC. That is, SCE proposes a one-way balancing account that refunds any over-estimate of the revenue requirement (cumulative over the 2-year period) associated with its forecasted 2013 and 2014 capital additions, including the cost of removal.[1655]

16.2.2.3. SCE's Claim of Error Regarding Other Operating Revenues in the TY 2009 Decision

SCE states that "…[a]nother flaw in the 2009 adopted post-test year ratemaking mechanism was its treatment of Other Operating Revenues (OOR). OOR arises from various services such as late fees, in which individual customers provide revenues to offset SCE's revenue requirement…"[1656]

SCE goes on to assert that D.09-03-025 "…did not authorize SCE to increase any of those fees to provide for additional revenues. In other words, the decision's post-test year mechanism implicitly assumed SCE would be able to increase tariffed OOR by 4.25 percent in 2010 and 4.35 percent in 2011 but did not authorize any increase in the fees that generate that OOR. In 2010 this disconnect created a $5 million shortfall between the adopted post-test year method and the revenues from fees for tariffed services, an amount that grew to $10 million in

---

[1654] Ex. SCE-10, Vol. 1, p. 105, lines 6-12.

[1655] Ex. DRA-21, p. 11.

[1656] Ex. SCE-10, Vol. 1, p. 111, lines 20-22.

2011."[1657] SCE recommends that "…the post-test year ratemaking mechanism the Commission adopts in this 2012 GRC should avoid this kind of methodological inconsistency.

16.3. DRA's Recommendations

DRA does not oppose a PTYR mechanism in 2013 and 2014 that provides SCE with some reasonable level of attrition increases in its revenue requirement. However, SCE's proposed Post Test Year revenue increases of $598 million (or 9.5%) in 2013 and $612 million (or 8.9%) in 2014 are excessive.

DRA estimates post test year net revenue increases of $218.8 million (or 4.0%) in 2013 and $119.4 million (or 2.1%) in 2014. These increases reflect DRA's forecasts of $5.658 billion in revenue requirement for 2013 and $5.777 billion for 2014.[1658] Adopting DRA's recommendations will allow SCE sufficient funds to operate efficiently and productively between rate cases, and encourage SCE to manage costs.

16.3.1. Components of DRA's Primary Recommendation for a PTYR Mechanism

DRA's primary recommendation for an attrition mechanism consists of four components. These are as follows:

- Increasing the 2012 base revenue requirement by the Urban Consumer Price Index (CPI); however, the starting point has to be adjusted to remove the 2012 revenue requirement associated with the Four Corners Generating Station, since SCE plans to sell its share of the plant.[1659]
- Incorporating the SmartConnect revenue requirement beginning in 2013, which does not require any escalation in the attrition years.
- Incorporating the difference between DRA's 2012 and 2013 forecast for customer service-related expenses, as discussed above in Section 6 of this Brief, into the development of 2013 and 2014 attrition revenue requirement.
- Finally, the revenue requirement associated with amortizing SCE's undepreciated legacy meters, as discussed in Section 20.6 of this Brief, is developed separate from base margin revenues, and is already included in DRA's 2012 revenue requirement. Since the amortization amount is

[1657] Ex. SCE-10, Vol. 1, p. 112, lines 5-10.

[1658] See Ex. DRA-21, p. 12, footnote 25. DRA refers to its attrition increases as "net" increases because they are net of any revenues associated with the Four Corners power plant.

[1659] By A.10-11-010, SCE presents a "Purchase and Sale Agreement" between SCE and Arizona Public Service, the operator of the Four Corners plant. Under the terms of the agreement, the forecast closing of the sale is October 1, 2012.

embedded in 2013 and 2014 rates at the 2012 level, it does not require any escalation in the attrition years.[1660]

16.3.1.1. DRA's PTYR Mechanism Increases Base Revenues by the Consumer Price Index

DRA recommends that the Commission set Post Test Year base margin revenue increases for SCE at 2.0% for 2013 (i.e., a 2.0% increase over the 2012 base margin revenue requirement) and 2.2% for 2014 (i.e., a 2.2% increase over the 2013 base margin revenue requirement), net of any revenue requirement associated with the Four Corners Generating Station since SCE has requested authority to sell its share of the plant. The percentage factors are obtained from a recent forecast of the Urban Consumer Price Index (CPI) for those two years.[1661]

In the past, DRA has supported and recommended using the CPI as a basis for determining Post Test Year revenue increases. The CPI indexing method is simple and would avoid the use of multiple indices that SCE's proposal entails. For example, in D.06-05-016, the Commission acknowledged that the CPI methodology had "...been recently adopted by the Commission in determining attrition for PG&E and SDG&E…" and that "...in those cases, the CPI methodology would provide reasonable results."[1662]

The revenue increases proposed by DRA are reasonable and consistent with recent attrition increases granted by the Commission to other California energy utilities, with one exception. In contrast, the Post Test Year increases of 9.5% and 8.9% proposed by SCE significantly exceed the attrition increases granted to any California energy utilities during the past several years. For example:

- In D.07-03-044, the Commission adopted a settlement agreement in PG&E's 2007 general rate case, which increased PG&E's revenue requirement for Electric Distribution, Gas Distribution, and Electric Generation by set amounts of $125 million per year from 2008 through 2010, which amounted to increases of about 2.5% per year.[1663]

[1660] Ex/.DRA-21. p. 14.

[1661] IHS Global Insight Cost Planner Fourth-Quarter 2010, page 11, Purchasing Environment, Table A1, Aggregate Price and Wage Forecasts, Consumer Price Index, CPI, All Items, Urban (CPI %). (See Ex. DRA-21 p. 14., footnote 27.)

[1662] D.06-05-016, mimeo., at pp. 301 and 303.

[1663] Decision Authorizing Pacific Gas & Electric Company's General Rate Case Revenue Requirement for 2007 – 2011 (2007) D.07-03-044, mimeo., at pp. 2, 10 and 11.

- In D.08-07-046, the Commission adopted a settlement agreement pertaining to SDG&E's and SoCalGas' 2008 general rate cases, which authorized attrition increases of approximately 3.1% per year from 2009 through 2011 for each of the two utilities.[1664]

- In D.08-11-048, the Commission adopted a settlement agreement pertaining to Southwest Gas Corporation's 2009 general rate case, which authorized annual attrition increases of 2.95% for the utility's Southern California and Northern California Divisions.[1665]

- In D.09-03-025, which addressed SCE's 2009 general rate case, the Commission authorized Post Test Year increases of 4.25% in 2010 and 4.35% in 2011.[1666]

- In D.09-10-041, the Commission adopted a settlement agreement pertaining to Sierra Pacific Power Company's 2009 general rate case, which authorized a Post Test Year Adjustment Mechanism (PTAM). The PTAM for 2010 and 2011 was based on the September Global Insight "U.S. Economic Outlook" forecast of CPI less a 0.5% productivity factor.[1667]

- In D.10-09-010, the Commission adopted a settlement agreement pertaining to PacifiCorp's 2011 general rate case, which authorized a Post Test Year Adjustment Mechanism (PTAM). The adopted PTAM was a continuation of the mechanism previously authorized for PacifiCorp in its 2007 GRC (D.06-12-011), which was based on the Global Insight "U.S. Economic Outlook" forecast of CPI with an off-setting productivity factor of 0.5% (CPI - 0.5%) or zero.[1668]

- In D.11-05-018, the Commission adopted a settlement agreement in PG&E's 2011 GRC, which increased PG&E's post test year revenue requirement by set amounts of $180 million in 2012 and $185 million in 2013, which amounted to increases of about 3.0% per year.[1669]

[1664] Decision on the Test Year 2008 General Rate Cases for SDG&E and SoCalGas (2008) D.08-07-046, mimeo., Appendix 3 (for SDG&E) and Appendix 4 (for SoCalGas).

[1665] Decision Adopting Test Year 2009 General Rate Increases (and Decrease) for Southwest Gas Corporation (2008) D.08-11-048, mimeo., Settlement Attachment 7, Sheets 1 and 2.

[1666] D.09-03-025, mimeo., at pp. 305-306.

[1667] Decision Adopting Settlement Agreement in General Rate Case of Sierra Pacific Power Company (2009) D.09-10-041, mimeo., at p. 9.

[1668] Decision Adopting Settlement Agreement (Pacificorp) (2010) D.10-09-010, mimeo., pp. 9-10.

[1669] D.11-05-018, mimeo., at p.15 and pp. 18-19.

Adopting a CPI-based mechanism for Post-Test Year Ratemaking has proved sufficient to provide other large energy utilities with the funding necessary to operate efficiently and productively between rate cases. The Commission should adopt such a mechanism for SCE in this GRC.

16.3.1.2. A PTYR Mechanism Based on CPI Gives SCE a Needed Incentive to Manage Costs

SCE's wage escalation rates during 2008-2012 are over 30% higher compared to the average hourly earnings for utilities.[1670] The PTYR mechanism which DRA recommends relies on the CPI to determine revenue increases, and implicitly provides for wage increases of 2.0% in 2013 and 2.2% in 2014. A CPI-based attrition mechanism would provide SCE with a much-needed incentive to better manage its labor expenses going forward, beyond 2012.

SCE is currently forecasting labor escalation rates of 2.86% in 2013 and 2.90% in 2014,[1671] based on recent Global Insight projections. As discussed earlier, SCE proposes to incorporate actual union wage increases and target wage increases for non-represented employees into the 2013 and 2014 PTYR advice letters should such increases be granted prior to the adoption of a Phase 1 decision of the GRC.

In other words, SCE does not have negotiated wage escalation rates in place for the 2013-2014 attrition years. Given that wage increases have not yet been determined for those two years, SCE now has the opportunity to control its labor costs for 2013 and 2014. The Commission should not give SCE a "blank check" to obtain guaranteed recovery from ratepayers any increase it negotiates, as that gives SCE management no incentive to control its labor costs. If the costs associated with wage increases are automatically passed-through to ratepayers, SCE has no reason, and has shown no inclination, to aggressively negotiate in order to minimize ratepayer impacts.[1672]

16.3.2. DRA Recommendations on Other SCE Proposals

In Section 6, above, DRA addresses SCE's CSBU costs, and forecasts certain expense levels for 2012 and 2013. The $48.1 million difference in DRA's forecasts[1673] reflects how

---

[1670] Ex. DRA-21, p. 16, Table 21-4.

[1671] Ex. SCE-10, Vol. 1, p. 64, line 8.

[1672] Ex. DRA-21, p. 17.

[1673] Ex. DRA-10 illustrates the difference between DRA's recommended CSBU expenses for 2012 in

SCE's CSBU expenses are expected to decrease in 2013 relative to 2012. Therefore, the lower expenses should be reflected in the development of post test year revenues.[1674]

16.3.2.1. Annual Advice Letters

DRA has reviewed SCE's request and does not disgree with SCE's proposed procedure for requesting attrition adjustments for 2013 and 2014, i.e., that SCE be allowed to file advice letters by November 1 of 2012 and 2013, respectively. However, DRA wishes to clarify that the advice letters are to be filed no earlier than October 2 because SCE intends to rely on escalation rates available from Global Insight on October 1 of the year in which the PTYR advice letters are filed.

In addition, the advice letters should demonstrate that all revenue requirements[1675] associated with the Four Corners Generating Station (e.g., operation and maintenance expenses, net plant, rate base items, pensions and benefits associated with SCE labor) are removed, since SCE plans to sell its share of that power plant in 2012.[1676]

16.3.2.2. SmartConnect

SCE anticipates that full deployment of the Edison SmartConnect Program will be achieved by the end of 2012, and forecasts that the revenue requirement associated with full deployment will be $251.3 million beginning in 2013.

SCE states that, "…[a]lthough not anticipated, if a delay should occur and deployment continues into 2013, SCE proposes to continue to recover the CSBU "business as usual" portion of the authorized 2012 revenue requirement in 2013 and through the end of deployment."[1677] Once that delayed (beyond December 31, 2012) deployment end date is known, SCE proposes to file an advice letter to adjust the 2013 revenue requirement to reflect the appropriate ratemaking.[1678] DRA does not disagree with this proposal if full deployment is delayed.

Table 10-1a and expenses for 2013 in Table 10-1b. I.e., $274.2 million - $226.1 million = $48.1 million.

[1674] Ex. DRA-21, p. 18.

[1675] Including, but not limited to, operation & maintenance expenses, net plant, materials and supplies inventory, coal fuel costs as part of working cash, ad valorem taxes, and deferred taxes.

[1676] By A.10-11-010, SCE presents a "Purchase and Sale Agreement" between SCE and Arizona Public Service, the operator of the Four Corners plant. Under the terms of the agreement, the forecast closing of the sale is October 1, 2012.

[1677] Ex. SCE-10, Vol. 1, p. 28, lines 23-25.

[1678] Ex. SCE-10, Vol. 1, p. 28, line 25 through p. 29, line 3.

DRA does not dispute the general concept of incorporating SmartConnect revenues into the 2013 revenue requirement. However, SCE's forecast does not take into account the impacts of the Tax Relief Act of 2010 which, for example, allows for 100% bonus depreciation beginning September 8, 2010 through the end of 2011, and 50% bonus depreciation in 2012. In response to a data request, SCE updated its forecast and arrived at a figure of $227.7 million.[1679] DRA recommends that no more than $227.7 million of SCE's requested $251.3 million in SmartConnect revenue requirement be rolled into the 2013 revenue requirement.

16.3.2.3. Nuclear Refueling Outages

DRA does not dispute SCE's proposal regarding nuclear refueling outages at SONGs during the post Test Year period.[1680]

16.3.2.4. Treatment of Major Exogenous Cost Changes

DRA has reviewed SCE's request and generally does not dispute SCE's proposal that the existing Z-Factor mechanism be continued in this rate case. The Z-Factor mechanisms adopted by the Commission have established a way to protect both the utilities and ratepayers by allowing for Post Test Year adjustments for unexpected and uncontrollable events.

D.04-07-022 indicates that SCE's existing Z-Factor mechanism allows the utility to:

> "…submit a letter of notification to the Commission's Executive Director to identify any potential Z-Factor event. SCE is at risk for events that do not have a revenue requirement impact of more than $10 million, and there is a $10 million 'deductible' applied on a one-time basis to the first year's revenue requirement associated with any approved Z-Factors."[1681]

That same decision also states:

> "As SCE points out, if a major change in tax law were to reduce its tax liabilities…, we might seek to reduce SCE's rates so that these benefits flow to customers prior to SCE's next GRC test year... Not

[1679] Ex. DRA-21, p. 19, footnote 45 citing SCE's **May 5, 2011** supplemental response to data request DRA-231-CKT, Question 1c. In that supplemental response, SCE estimates that the impact of bonus depreciation will decrease the 2013 SmartConnect revenue requirement from $251.303 million to $227.731 million. However, it is interesting to note that the **April 20, 2011** version of the Results of Operations model (updated to include the impacts of the Tax Relief Act of 2010) shows a figure of about $209 million as the SmartConnect revenue requirement for 2013.

[1680] Ex. DRA-21, p. 20.

[1681] D.04-07-022, mimeo, at pp. 278-279.

> unreasonably, SCE expects similar treatment in the event of a major exogenous increase in its costs."[1682]

The Z-Factor mechanism adopted for SCE should encompass exogenous changes that can decrease utility costs (such as tax rate changes or tax law changes), i.e., that it is not limited to changes that only increase the utility's costs.

SCE should also be reminded of the Z-Factor criteria outlined by the Commission in D.05-03-023[1683] and that there is no presumption of recovery of an identified Z-Factor event until the incurred costs have been found to be reasonable.

In Rebuttal, SCE says that "DRA's testimony neglects to mention that D.05-03-023 approved a settlement involving post-Test Year ratemaking mechanisms for San Diego Gas & Electric Company and Southern California Gas Company." SCE goes on to say that, "[t]he decision clearly states that the settlement is not precedent for any future proceeding" and "[as] such, it does not apply to SCE…."[1684]

The citation to D.05-03-023 in DRA's testimony[1685] refers to the page which sets forth the nine criteria the Commission has adopted for Z-factor treatment, independent of any settlement. That same decision states that the burden of proof is on the utility seeking Z-factor recovery, "….to show that they completely responded to the event in a reasonable and efficient manner before they can recover any costs in a Z-factor Memorandum Account."[1686]

If SCE is suggesting by its Rebuttal that it considers itself excused from meeting this burden of proof, then DRA believes it all the more imperative that the Commission remind SCE otherwise.

16.3.2.5. Application Should Not Be Required to Implement PTYR

DRA agrees that SCE should not be required to submit an application to approve the PTYR mechanism which is ultimately adopted by this Commission in this proceeding.[1687]

[1682] D.04-07-022, mimeo., at p. 279.

[1683] D.05-03-023, mimeo., at p. 30.

[1684] Ex. SCE-25, Vol. 1, p. 49.

[1685] See D.05-03-023, mimeo, p. 30.

[1686] Id., at p.31.

[1687] Ex. DRA-21, p. 21.

16.3.2.6. SCE's Claim of Error for "Stranded Construction Work In Progress"

SCE argues that the Commission's decision in the 2009 GRC forced SCE to temporarily restrain capital investment which resulted in "stranded" CWIP. Meanwhile, SCE indicates that even though it "…could not spend at the levels ostensibly authorized for 2009…we were able to do so over the cumulative three-year cycle (2009-2011)."[1688]

SCE's arguments are not persuasive. SCE could have filed an application for hearing or a petition for modification if it had factual evidence that the adopted decision was in error. SCE did not do so.[1689]

16.3.2.7. Budget Based Capital Additions

SCE also proposes that, in this GRC, the Commission adopt the same capital-related PTYR mechanism which was adopted in the 2003 GRC, i.e., creating a one-way balancing account that refunds any over-estimate of the revenue requirement (cumulative over the 2-year period) associated with its forecasted 2013 and 2014 capital additions, including the cost of removal.

DRA opposes a PTYR mechanism that relies upon SCE's budget-based estimate of 2013 and 2014 capital expenditures for reasons discussed in Section 16.3.3.1, below. If, however, the Commission were to adopt a PTYR mechanism which relies on budget-based capital expenditures for 2013 and 2014, then DRA does not oppose the establishment of a one-way balancing account.[1690]

16.3.2.8. Separate Escalation of Other Operating Revenues

SCE argues that the post test year mechanism adopted in D.09-03-025 implicitly assumed that the utility would be able to increased tariffed OOR by certain percentages in 2010 and 2011, but did not authorize any increase in the fees that generate that OOR. SCE requests that the PTYR mechanism adopted in this GRC avoid this type of methodological inconsistency.

This argument was appropriately addressed and disposed of when, on October 30, 2009, SCE filed Advice Letter 2396-E seeking an OOR adjustment and, by letter dated December 2,

---

[1688] Ex. SCE-10, Vol. 1, p. 105, lines 11-12.

[1689] Ex. DRA-21, p. 22.

[1690] Ex. DRA-21, p. 22.

2009, the Commission's Energy Division advised SCE to supplement AL 2396-E to remove the OOR adjustment.[1691]

In D.09-03-025, the Commission authorized specific pre-set post test year revenue requirement levels for SCE in 2010 and 2011 which implicitly incorporated all issues including the impact of Other Operating Revenues. The Commission may elect to do the same in the final decision which addresses SCE's 2012 rate case.[1692]

16.3.3. DRA's Alternate Recommendation for a PTYR Mechanism

If the Commission does not adopt DRA's primary recommendation on SCE's Post Test Year revenue increases as discussed above, and instead relies on a mechanism similar to SCE's proposal, then DRA proposes a mechanism whereby attrition increases are based on: (1) increasing the adopted 2012 level of plant additions for general inflation; and (2) increasing the adopted 2012 level of operational expenses for general inflation, as proposed by DRA, except for medical benefits costs, which are escalated separately.[1693]

16.3.3.1. PTYR Capital-Related Adjustments

SCE proposes a PTYR mechanism using budget-based plant (capital) addition forecasts for 2013 and 2014. DRA, instead, recommends a mechanism which escalates the adopted 2012 plant additions by 2.5% per year to develop the 2013 and 2014 figures.[1694]

DRA believes that using the adopted test year levels of plant additions is more reasonable, and consistent with past Commission precedent, in contrast to relying solely on budget-based attrition-year forecasts. This is because the farther out in time project-based plans are projected, the greater the likelihood that the projects themselves, and/or the expenditure levels, will change or be eliminated. In addition, DRA and other parties normally do not possess the resources to conduct a detailed analysis of the utility's budget-based plant additions for years beyond the test year.

[1691] The letter from Energy Division to SCE also advised the utility that it could file a petition to modify D.09-03-025 if SCE believed that the Commission intended to allow it to make an OOR adjustment. To DRA's knowledge, SCE did not do so. (Ex. DRA-21, p. 23, footnote 50.)

[1692] Ex. DRA-21, pp. 22-23.

[1693] Ex. DRA-21, p. 23.

[1694] This methodology for determining capital additions in the attrition years is consistent with the methodology that was adopted for SCE in D.06-15-016, *mimeo.*, at pp. 305-306. DRA's recommended 2.5% per year capital escalation rate is consistent with the one adopted in D.06-15-016, *mimeo*., at p. 308.

In SCE's 2009 GRC, the utility described its PTYR mechanism as budget-based. The Commission's decision on that case stated:

> As we repeatedly observed in prior decisions, there is a fundamental problem with budget-based ratemaking that boils down to the fact that budgets are not always implemented as planned. In addition, no other party other than SCE provided or analyzed detailed post-TY plant addition budget forecasts in determining increases. We cannot fault other parties for not recommending detailed PTYR capital budgets. As we have noted in past GRCs, analyzing such budgets for two additional years imposes a significant burden on resources. For these reasons, we reject SCE's proposal for budget-based cost increases.[1695]

This approach to determining attrition-year plant additions estimates is reasonable because it does not rely solely on SCE's forecasts of 2013 and 2014 capital additions that DRA and other parties could not review and analyze in detail. Instead it relies on the adopted 2012 level of capital expenditures (and, hence, plant additions) that DRA and other parties *were* able to review and analyze in detail, and which the Commission has been able to review after a thorough evaluation of a complete record.

16.3.3.2. PTYR Expense-Related Adjustments

DRA does not disagree with the general concept of determining attrition expense increases by escalating the adopted 2012 expense levels. However, DRA does dispute SCE's proposed escalation rates for medical benefits costs and labor costs in 2013 and 2014. These are discussed below.

Medical Benefits Costs

The forecasts for medical benefits costs should not be increased by 10.5% per year in 2013 and 2014, as SCE proposes. Instead, DRA recommends that the medical benefits costs should be escalated by 5.0% in 2013 and 6.0% in 2014,[1696] pursuant to the forecasted group health insurance escalation rates appearing in the IHS Global Insight Cost Planner Fourth-Quarter 2010. This is the same source which DRA relies on for the medical benefits escalation

---

[1695] D.09-03-025, mimeo., at p. 305.

[1696] Ex. DRA-21, p. 25, footnote 53 citing IHS Global Insight Cost Planner Fourth-Quarter 2010, p. 149, Additional Forecast Tables, Table A1, Corporate Expenses, Health Care Benefits, ECI, Group Health Insurance (ECIHI %).

rates recommended above in Section 8 of this Brief. It is also the same source relied upon for non-labor escalation rates.

Wage Escalation Rates

SCE should not be allowed to rely on wage increases that may be negotiated prior to the time the utility files for attrition relief. Rather than automatically passing through to SCE ratepayers the future union wage increases or the target wage increases for non-represented employees, the Commission should consider a less costly alternative.

In its testimony, DRA proposes one such alternative. Instead of using SCE's negotiated wage increases in place at the time the utility seeks attrition relief, the adopted PTYR mechanism should incorporate recently forecasted CPI escalation rates of 2.0% for 2013 and 2.2% for 2014.[1697] Given that SCE's wage escalation rates during the 2008-2012 time period have been high compared to the Global Insight figures, DRA has presented what it considers a reasonable and fair alternative to SCE's approach.[1698]

DRA's approach uses the annual wage escalation rates that DRA recommends for 2010, 2011, and 2012, 2.80%, 2.49%, and 2.22% respectively,[1699] and rates equal to 2.0% for 2013 and 2.2% for 2014. When compounded, the wage escalation rates over the 5-year period from 2010-2014 and the 7-year period from 2008-2014 would still be higher than those based on data from IHS Global Insight. Thus, if the Commission were to set SCE's wage escalation rates for 2013 and 2014 as DRA recommends, the ratepayers would be funding generous wage increases to SCE employees in those specific years and over a multi-year time period.

In fact, if one were to take the SCE percentages for 2008-2012, but set the wage escalation rates for 2013 and 2014 at 1.29% per year, SCE's compounded increases over the 5-year period from 2010-2014 would equal those as measured by the IHS Global Insight index, and, over the 7-year period, from 2008-2014, would still exceed those as measured by the IHS Global Insight.[1700] DRA provides this information in the event that the Commission believes DRA's recommended wage escalation rates of 2.0% for 2013 and 2.2% for 2014 are too high.[1701]

[1697] See Ex. DRA-21, p. 14, footnote 27.

[1698] Ex. DRA-21, p. 26, Table 21-5.

[1699] See Ex. DRA-4.

[1700] Ex. DRA-21, p. 26, Table 21-5.

[1701] Ex. DRA-21, p. 27, footnote 56.

The Commission should also keep in mind that SCE proposes to incorporate actual union wage increases and target wage increases for non-represented employees into its 2013 and 2014 PTYR advice letters. Hence, the SCE figures for 2013 and 2014 could be even higher than currently presented, in which case, the compounded increases would be even more pronounced.

SCE's proposal is essentially a blank check. If adopted, SCE's ratepayers have no protection from excessive wage increases that SCE may negotiate.

In Rebuttal, SCE says, "[a]s a first matter, SCE is not requesting unlimited ratification of future union wage increases or target wage increases for non-represented employees as DRA implies in its testimony."[1702] SCE goes on to say that "[w]hat SCE proposed in its direct testimony on post-Test Year ratemaking was that '[f]or the annual advice letters, union wage increases and target wage increases for nonrepresented employees *granted prior to the adoption of a Phase 1 decision in this application* will be incorporated in the labor escalation rates used in the 2013 and 2014 PTYR advices letters."[1703]

This is exactly DRA's point. The collective bargaining agreements SCE has with its represented employees expire at the end of 2011.[1704] Thus, if SCE reaches an agreement with its represented employees to give them 5%, 10% or 15% per year increases for 2013 and 2014, there is nothing to stop SCE from incorporating these labor escalation rates in its TY 2013 and 2014 PTYR advice letters.

In Rebuttal, SCE also says that "[t]he larger implication of DRA's proposal is that DRA does not believe that utility employees should enjoy increases in their standard of living."[1705] SCE is mistaken. DRA would hope that everyone could enjoy increases in their standard of living. What DRA opposes is SCE's attempt to make its already struggling ratepayers pay even more for increases in the standard of living for SCE's employees. DRA can only assume that, in making this argument, SCE is completely out of touch with the desperate circumstances of many of its customers as expressed at Public Participation Hearings, and as shown in reports of the unemployment, underemployment rates in SCE's service territory.

[1702] Ex. SCE-25, Vol. 1, p. 47.

[1703] Id.

[1704] Ex. SCE-10, Vol. 1, p. 63, lines 29-32.

[1705] Ex. SCE-25, Vol. 1, p. 47.

Nothing in SCE's testimony causes DRA to change its recommendation. The Consumer Price Index "...is often used to adjust consumers' income payments (for example, Social Security) to adjust income eligibility levels for government asisstance and to automatically provide cost-of-living wage increses to millions of American workders."[1706] If SCE believes that improving the standard of living of its employees beyond that of "...Social Security beneficiaries, and military and Federal Civil Service retirees..."[1707], perhaps SCE's shareholders would like to make up the difference.

In the past five years, SCE has shown no propensity to negotiate wage increases commensurate to other comparable utility wage increases. The Commission should not just automatically pass through to ratepayers the utility's future wage increases for union and non-represented employees. DRA proposes that the Commission adopt a less costly alternative for SCE's ratepayers.

Non-Labor Escalation Rates

DRA does not oppose SCE's request to incorporate updated non-labor escalation rates based on the lates HIS Global Insight escalation rates available on October 1 of the year in which SCE files for attrition relief.[1708]

17. Productivity

SCE gauges its productivity performance over the historic and forecast period by constructing several measures of total and partial productivity.[1709]

SCE presents two measures of total factor productivity growth. The first, based on output measured as revenue weighted sales, and an alternative with output defined as peak demand. These output measures were also used in SCE's partial productivity analysis. DRA first replicated SCE's total and partial productivity results. DRA then developed total and partial productivity measures based on a third output measure, the total number of electric customers.[1710]

[1706] Ex. DRA-81, Response to DRA to SCE-CKT-032, p. 4 of 4.

[1707] Ex. DRA-81.

[1708] Ex. DRA-21, p. 27.

[1709] Ex. DRA-20, p. 1.

[1710] In its test year 2003 General Rate Case, A.02-005-004, SCE reported productivity results based on output defined as the number of electric customers.

Based on DRA's replication of SCE's productivity findings and DRA's total and partial productivity results with its customer based output measure, DRA concludes that SCE's productivity results are reasonable. Furthermore, DRA recommends no additional adjustments to SCE's Results of Operations (RO) beyond those recommended by DRA's RO witnesses.

Finally, DRA agrees with SCE's conclusion that: "Because they are conducted at such a high level, the total factor productivity studies that are typically provided in a General Rate Case proceeding do not generally yield useful data for utility operational and investment decisions. They can be useful in the context of certain types of performance-based ratemaking, but…they have not proven useful in General Rate Cases. The Commission should remove the requirement that SCE submit a corporate productivity study in the General Rate Case."[1711]

18. Electric Plant

DRA's recommendations relating to Gains/ Losses on Sale of Property are discussed above in Section 6.5, Customer Service, Other Operating Revenue.[1712]

19. Taxes

For Test Year 2012, SCE is requesting recovery for $630.682 million in Taxes on Income, $96.213 million in Payroll and Other Taxes, and $202.454 million in Ad Valorem Taxes. Of this total $929.349 million in tax expense, DRA is recommending a decrease of $6.346 million.[1713] DRA's adjustments are in two areas: meals and entertainment deductions and research and development tax credits.

19.1. Meals and Entertainment Expenditures

Tax laws place a limit of 50% on the deduction for meals and entertainment expenditures. To reconcile this limit for regulatory taxes, SCE includes a negative deduction equal to 50% of its estimates of the amount of meals and entertainment that are embedded in its capital, operations and maintenance, and administrative and general expenses.

In SCE's 2009 GRC, SCE's estimate was a four-year average of the most recent recorded data. In that GRC, DRA asked SCE to allocate SCE's meals and travel expenses into business-related versus entertainment. SCE responded that:

[1711] Ex. DRA-20, p. 2 citing Ex. SCE-11, p. 4.

[1712] See also Ex. DRA-10, p. 93.

[1713] Ex. DRA-18, p. 2.

> The DPB 5558 Report is designed to capture the business costs which are subject to the limitations imposed by Internal Revenue Code section 274(n) and is used in calculating the company's income tax liability. As such, it does not contain a listing or sort of all of the company's business meals, meals, entertainment or travel that you have requested. It simply lists the individual incurring the cost and the amount incurred each month that is subject to the section 274(n) limitation. We do not maintain a listing with the sort and detail that you have requested.[1714]

To the extent that the applicant's workpapers and accounting system do not provide accounting records in a manner in accord with such precedent, DRA has a duty to recommend that the expenditures be removed from consideration for ratesetting. For example, if SCE's accounting records do not distinguish between entertaining and business, then SCE cannot remove entertainment-related activities from its applications. In this regard, DRA's adjustment is supported by prior Commission decisions, which have twice rejected entertainment-related expenses (e.g., Disneyland tickets, luncheons, retiree dinners) from ratesetting because they are an unfair economic burden[1715] and ratepayers should not be required to pay for them.[1716]

Furthermore, the Commission has rejected entertainment expenditures because they give the appearance of a "free lunch" at ratepayers' expense.[1717] SCE's entertainment expenses would fall under the same category of expenses that the Commission has rejected in the past.[1718]

In this GRC, as a result of new accounting software, SCE can now distinguish somewhat between business meals and entertainment, and SCE attempted to provide a more transparent breakout of costs.[1719] However, rather than using a four-year average as it done in the 2009 GRC, SCE used a two-year average that corresponds with the most recent data provided by SCE's new accounting software. SCE identifies 10.36% of total business meals and entertainment budget related to entertainment expense and says that it has reduced the non-deductible meals negative deduction accordingly.[1720]

[1714] Ex. DRA-18, p. 2 citing SCE TY 2009 Response to Data Request DRA-SCE-132-MRL Q/A2.

[1715] D.82-12-054; 10 CPUC 2d at 140-141.

[1716] D.93-12-043; 52 CPUC 2d at 513-514.

[1717] D.90-01-016; 35 CPUC 2d 80 at 135-136.

[1718] Ex. DRA-18, p. 4.

[1719] Ex. DRA-18, p. 4 citing Workpapers to Ex. SCE-10 Vol.2 , Ch. III, pp. 42-45

[1720] Ex. DRA-18, p. 4.

DRA continues to disagree with the manner in which SCE derives the negative deduction. The negative deduction is based on historic data from 2008 and 2009 recorded data (Tax Return Schedule M); however, it does not take into account the actual amounts forecasted in the 2012 GRC. As these costs are embedded in the various FERC accounts, and are not easily identified, DRA has no way of verifying that use of two year's of historic data is an accurate measure of what has actually been forecasted by SCE throughout the 2012 GRC for business meals and entertainment. SCE has now derived a factor, but still needs to clearly identify the amount of business meals and entertainment forecasted in the 2012 GRC to which that fact should be applied.[1721]

For example, if in aggregate, amounts forecasted in the 2012 GRC were much lower than then the averaged two years of historic data, this would result in a potentially lower deduction. It could also result in a higher deduction, but without some level of proof as to the actual amounts forecasted, DRA would be agreeing in the dark. Further, it is SCE's burden of proof to show the amounts embedded throughout the various FERC accounts for business meals and entertainment, in some way represent the historical data used.

Given SCE's inability to show the amounts embedded in the 2012 GRC forecasts for business meals and entertainment, DRA recommends full removal of $5,246,000 negative deduction for 2012, and related amounts for 2013, and 2014. In future rate cases, DRA recommends a break out of business meals and entertainment expenses by FERC Account. Then SCE can attempt to estimate and remove those amounts related to entertainment based on historic known data rather than a limited two-year estimate.[1722]

19.2. Research and Development Tax Credits

In attempting to determine whether SCE used all available tax credits for 2012 forecasting purposes, DRA inquired as to the status of R&D tax credits pursuant to IRS Code Section 41. In an initial response to DRA's data request regarding R&D tax credits,[1723] SCE said:

> The R&D credit is not reflected in the 2012 GRC income tax expense forecast. The R&D credit is currently the subject to a limitation and the

[1721] Ex. DRA-18, pp. 4-5.

[1722] Ex. DRA-18, p. 5.

[1723] Ex. DRA-18, p. 5, citing DRA-SCE-AUDIT-LMW-012-Supplemental 2-Group 4.2-Q/A.3.d

> unused credit is being carried forward to future periods beyond the 2012 GRC.

Based on this, DRA understood a R&D tax credit would be available; however, the tax credit is being carried forward to future periods beyond the 2012. A subsequent response from SCE, however, said that:

> Under current tax law, the R&D credit is scheduled to expire on December 31, 2011 and as such, no R&D credit will be available during the 2012 GRC period. At the filing of the GRC application, any carryforward credit is expected to be used prior to 2012.[1724]

The two responses appear to be inconsistent, but DRA believes both are correct. The R&D credit is scheduled to expire; however, R&D credits already available can be carried forward. The reason no R&D credit will be available during the 2012 GRC period is that SCE expecting to use this credit prior to 2012.

It should be noted SCE's response to use of the credit is an expectation, rather than a definitive. Regardless of the reason, it appears this credit can be carried forward to the 2012 GRC if SCE does not use the credit. In its testimony, therefore, DRA recommended that the Commission include the $1.1 million credit in SCE's forecasted income tax expense for 2012.[1725]

In Rebuttal, SCE says DRA's recommendation is "...not consistent with ratemaking principles."[1726] DRA disagrees. Ratepayers fund the R&D expenditures. It is clearly inequitable if the ratepayers who fund the R&D then receive no benefit for the R&D credit. In any case, Commission should also note the language of the IRC Code section itself which says that "[t]he *current* carry-back is one year and carry-forward is 20 years (section 39).[1727]" Thus, the entire tax forecast is subject to question given the manner in which income tax is forecast, and the sudden changeability of tax laws.

DRA continues to recommend the Commission include the $1.1 M credit in the TY 2012 forecast of income tax expense.

[1724] Ex. DRA-18, p. 7, citing DRA-SCE-222-LMW Q/A. 2.

[1725] Ex. DRA-18, p. 7.

[1726] Ex. SCE-25, Vol. 2, p. 6.

[1727] IRC Code 41 (section 39), emphasis added.

20. Rate Base

Rate Base is the depreciated asset value of SCE's net investments used to provide service to its customers. The major components of Rate Base are Fixed Capital, Adjustments, Working Cash, and Deductions for Reserves. SCE is allowed to earn a return on the sum of these Rate Base components. All Rate Base components are developed on a weighted average basis. DRA's Rate Base estimates reflect adjustments discussed in other areas of this Brief.

20.1. Customer Advances

Customer Advances for Construction (CAC) represent refundable amounts provided by applicants (usually developers) in advance of construction of new distribution facilities that will later be served by SCE. Developers are required to advance the construction costs that exceed the Commission's specified allowance formula pursuant to Distribution Line extension rules in the Tariff Rule 15. These funds are a liability to SCE until reimbursed to the developers. Consistent with the Commissions rules, SCE does not pay interest for holding these monies. Customer Advances for Construction are an interest free source of funds and are therefore an offset to rate base.[1728]

SCE forecasts ($75,386,000) in Customer Advances for Construction for 2012; DRA forecasts ($86,825,000).[1729] The differences between SCE's and DRA's forecasts are discussed below.

20.1.1. Electric Construction

The major component of Customer Advances is associated with Electric Construction. To forecast this component of Customer Advances, SCE relied on a methodology which takes the forecasted number of meter sets and multiplies them by an average advance per meter. DRA does not dispute SCE's forecast of meter sets but does dispute SCE's forecast of the average advance per meter.

SCE basically relied on data from 2007-2009 to develop a 3-year average cost of $374 (in 2009 dollars) per meter set, "…to properly reflect the recent economic downturn."[1730] DRA, however, recommends using a 5-year (2005-2009) average cost of $541 per meter to forecast

---

[1728] Ex. SCE-10, Vol. 2, Ch .IV, p. 47.

[1729] Ex. DRA-19, p. 4.

[1730] Ex. SCE-10, Vol. 2, Ch. IV, p. 48, lines 7-10.

Customer Advances for 2012. The 5-year average covers a longer time period which includes periods of some economic growth, smoothes the data, and takes into consideration that there is no certainty that the economic conditions in 2012 will be similar to those of 2007-2009, but are expected to slowly improve.[1731]

20.1.2. Temporary Services

Another component of Customer Advances is associated with Temporary Services. DRA disputes SCE's Temporary Services Advance Forecast methodology. SCE applied an annual -3.0% growth factor to its 2009 recorded amount of $7,552,525 to forecast its 2012 Temporary Services amount of $6,892,986. SCE's testimony fails to adequately explain why a -3.0% growth factor is necessary and appropriate. Therefore, DRA instead recommends using SCE's 2009 actual recorded amount of $7,552,525 as the 2012 Temporary Services Advance forecast.[1732]

20.2. Materials and Supplies

Materials and Supplies (M&S) inventory is maintained for new plant construction and O&M required to operate existing plant. The inventory is supposed to meet the demands of planned and unplanned projects. DRA disputes SCE's M&S forecasts associated with: (1) Transmission and Distribution; and (2) Other Generation (for the Peaker Project).

20.2.1. Transmission and Distribution

This inventory supports current transmission and distribution (T&D) project expenditures, such as infrastructure replacement and maintenance programs, and provides emergency inventory stock. SCE is requesting $144.747 million in its 2012 rate base for T&D M&S.[1733] SCE's request for 2012 is: (1) 39.2% higher than the recorded level of T&D M&S in 2009, which was $104.012 million;[1734] and (2) 24.7% higher than the recorded level of T&D

[1731] Ex. DRA -19, pp. 4-5.

[1732] Ex. DRA-19, p. 5.

[1733] Ex. SCE-10, Vol. 2, Ch. IV, p. 53, Table IV-15.

[1734] Id.

M&S in 2010.[1735] DRA recommends the Commission adopt SCE's recorded weighted-average 2010 level of $116.094 million.[1736]

SCE's forecast is based on a regression analysis of the three-year rolling average trend for the T&D capital expenditures and the T&D M&S inventory. Based on the results from a regression analysis, SCE concluded that for each $1 million in incremental T&D construction expenditures, there is a need for approximately $60,000 in additional T&D M&S inventory to support the project activity.[1737]

DRA disagrees with SCE's proposal,[1738] and, instead, recommends that the Commission authorize $116.094 million, SCE's recorded weighted-average 2010 level. This amount is consistent with recent historical data.[1739]

If, however, the Commission prefers SCE's methodology, DRA recommends that the T&D M&S be based on $40,000 in additional inventory for every $1 million of adopted T&D capital expenditures, instead of SCE's proposal for approximately $60,000 in additional T&D M&S inventory for every $1 million of adopted T&D capital expenditures. In D.09-03-025, the Commission adopted a factor of $40,000 of T&D M&S per $1 million of T&D capital expenditures.[1740] DRA recommends that the Commission adopt the same $40,000 factor in this rate case, as SCE has not justified why the factor needs to be increased to $60,000 of T&D M&S per $1 million of T&D capital expenditures.

The results from SCE's analysis in its 2009 GRC support the factor which the Commission adopted in the 2009 GRC. For both the R-square and Adjusted R-square coefficients from SCE's regression analysis, the results from the data used in the 2009 GRC have a better correlation than the data used in this GRC.[1741]

Using the same "$40,000 of additional T&D M&S inventory per $1 million of T&D capital expenditure" factor which was adopted in SCE's 2009 GRC, in conjunction with DRA's

---

[1735] Ex. DRA-19, p. 6, citing Attachment to SCE response to data request DRA-213-GSD, Q/A 1.

[1736] Ex. DRA-19, p. 6.

[1737] Ex. SCE-10, Vol. 2, Ch. IV, p. 52.

[1738] Ex. DRA0-19, p. 7, footnote 9.

[1739] Ex. DRA-19, p. 7.

[1740] D.09-03-025, mimeo, at p. 272.

[1741] Ex. DRA-19, p. 8, Table 19-3.

recommended level of T&D capital expenditures,[1742] yields an amount of $115.117 million for T&D M&S in 2012.[1743]

20.2.2. Other Generation – Peaker Project

SCE is requesting $837,000 in its 2012 rate base for M&S associated with its Peaker Project,[1744] which, according to SCE, "…is needed in order to support the peaker facilities currently built, and the fifth peaker expected to be online by the end of 2010."[1745]

SCE has indicated that the amount of M&S in 2012 associated with the fifth peaker is $42,000, or the difference between the forecasted $837,000 for 2012 and the 2009 recorded amount of $795,000. Consistent with DRA's recommendation in Section 4 of this Brief regarding the fifth peaker, DRA recommends a $42,000 adjustment to SCE's Other Generation M&S forecast.[1746]

20.3. Working Cash

SCE's total Working Cash request includes, among other things, Cash Balances, Prepayments, User Taxes and Other Fees and certain Lag Days. The areas where DRA disagrees with SCE's forecasts are discussed below.

20.3.1. Cash Balances

SCE includes $5.900 million for Cash Balances in its 2012 Working Cash Requirement.[1747] DRA recommends that this $5.900 million be removed from Rate Base and that no funding be included for Cash Balances. DRA's recommendation is consistent with D.09-03-025 and D.06-05-016, SCE's last two GRCs in which the Commission authorized no funding for Cash Balances.[1748]

The CPUC's Standard Practice U-16 states:

[1742] See Section 5 of this Brief, and references to Ex. DRA-6 and DRA-7.

[1743] Ex. DRA-19, p. 8.

[1744] Ex. SCE-10, Vol. 2, Ch. IV, p. 56, Table IV-17.

[1745] Ex. SCE-10, Vol. 2, Ch. IV, p. 56, lines 10-12.

[1746] Ex. DRA-19, p. 9.

[1747] Ex. SCE-10, Vol. 2, Ch. IV, Workpapers p. 62.

[1748] D.09-03-025, p. 266, and p. 388, Findings of Fact No. 193; and D.06-05-016, Appendix C, page C-23, line 1.

> In determining the cash requirement, *the only amounts which should be considered are the required minimum bank deposits that must be maintained* and reasonable amounts of working funds. The determination of the amount of money required to pay expenses in advance of receipt of revenues is made by the lag study. If funds were to be allowed in the cash requirement, over and above the minimum bank deposits for payment of certain operating expenses, it would have the effect of providing for payments of the same cost twice, once as determined in the lag study and once again in determining the operational requirement.[1749]

SCE itself acknowledges that it "... is not required by any of the [6] banks listed to maintain a cash balance greater the $0." Since the $5.900 million is not a "required bank deposit" as clearly set forth in Standard Practice U-16, DRA recommends that $5.900 million be excluded from the working capital requirement and rate base.

20.3.2. Prepayments

Prepayments include prepaid rents, software, license fees, insurance, gas options premiums, and other miscellaneous prepayments that have not been accrued to operating expenses. Because the utility is advanced these funds, the average balance is includable in working cash.[1750]

DRA recommends a total adjustment of $5.215 million (comprising $1.359 million for the Mountainview Hot Gas Path Fee and $3.856 million for T&D Prepaid Line Rents) to SCE's prepayments estimate, as discussed below.

Mountainview Hot Gas Path Fee

SCE includes $1.359 million in its Rate Base estimate[1751] for a Mountainview Hot Gas Path Fee prepayment for a contracted 2015 overhaul of the Mountainview Generating Station.

DRA recommends the entire $1.359 million for the Mountainview Hot Gas Path fee be removed from Rate Base. The Mountainview Generating Station is scheduled for an overhaul in early 2015, which is beyond the current 2012 GRC cycle. Even though SCE expects to incur a cost in 2014 for an early prepayment in October 2014 associated with the overhaul, SCE should

---

[1749] CPUC Standard Practice U-16, pp. 3-4, emphasis added.

[1750] Ex. SCE-10, Vol. 2, Ch. IV, p. 60, lines 21-24.

[1751] Ex. SCE-10, Vol. 2, Ch. IV Workpapers, p. 80.

not be allowed to charge ratepayers to normalize a 2014 prepayment backwards to the 2012 Test Year.[1752]

Transmission and Distribution Prepaid Line Rents

SCE forecasts $9.061 million in T&D Prepaid Line Rents by the end of 2012, and includes a weighted-average amount of $5.445 million in its 2012 rate base estimate.[1753]

To be consistent with the recommendations regarding T&D line rents discussed above in Section 5 of this Brief, DRA recommends using the 2009 weighted-average recorded level of T&D Prepaid Line Rents. Therefore, DRA's forecast is equal to $1.589 million, which results in a recommended adjustment of $3.856 million.[1754]

20.3.3. Lead-Lag Working Capital Requirement

SCE says that expense lag days "…represent the average time from recording the various operating costs to render service advanced by third party vendors and suppliers, investors, employees, and taxing agencies to the date of payment for those expenses…SCE's estimated expense lags…were developed using 2009 recorded payments incurred to serve customers."[1755]

DRA disagrees with SCE's estimate of lag days for Federal Income Tax, California Corporate Franchise Tax, and Funded Pension Provisions, as discussed below.

Federal Income Tax (FIT) Lag Days

SCE proposes 73.81 FIT lag days in this rate case.[1756] SCE's methodology was based on calculating a 5-year average (2005-2009) of previous FIT year tax lags days.

DRA used 4-year average of tax lag data from 2006 through 2009 to develop its estimate for FIT lag days. DRA chose a 4-year average because the data from 2005, which SCE uses, contains an anomaly that was uncharacteristic (due to tax refunds) compared to the other years during that 2005-2009 five-year time frame, and should not be expected to occur in 2012.

In Rebuttal, SCE says that "DRA's claim is unsupported. In fact, from 2002 – 2009, SCE experienced refunds in four of the eight years. Receiving refunds 50% of the time is hardly

---

[1752] Ex. DRA-19, p. 11.

[1753] Ex. SCE-10 Vol. 2, Ch. IV, Workpapers p. 81.

[1754] Ex. DRA-19, p. 11.

[1755] Ex. SCE-10, Vol. 2, Ch. IV, p. 68, lines 2-6.

[1756] Ex. SCE-10, Vol. 2, Ch. IV Workpapers p. 232.

anomalous."[1757] Reaching back eight years to find enough tax refunds to reach 50% is not, as far as DRA knows, a forecasting method widely used by this Commission. SCE is "cherry-picking" to make its argument here.

DRA continues to recommend that the Commission adopt an FIT of 88.71 lag days for 2012, based on a four-year average.[1758]

California Corporate Franchise Tax (CCFT) Lag Days

SCE proposes 52.96 days for CCFT lag days in this rate case.[1759] SCE's methodology was based on calculating a 5-year average (2005-2009) of previous CCFT year tax lags days.

DRA used 4-year average of tax lag data from 2006 through 2009 to develop its estimate for CCFT lag days. DRA chose a four -year average to develop its CCFT tax lag day estimate for the reasons described above. DRA recommends that the Commission adopt a CCFT of 68.95 lag days for 2012.[1760]

SCE's R/O Model Error

DRA also corrected an error SCE incorporated in its Results of Operations (R/O) model relating to the proper formula for calculating lead/ lag for Working Cash. DRA corrected the reference in one of the R/O model cells to acquire the value of the ratemaking Federal Tax.[1761] The way in which taxes are calculated for purposes of filing with taxing authorities is different from the way in which taxes are calculated for ratemaking purposes.[1762] DRA's correction is consistent with this Commission's long-standing practices and policies for calculating Working Cash.[1763]

20.4. Unfunded Pension Reserves

SCE proposes 17.00 lag days for Funded Pension Provisions in this rate case.[1764] SCE's methodology relies on averaging the actual total 2009 payment of $98,020,000 into four equal

---

[1757] Ex. SCE-25, p. 27.

[1758] Ex. DRA-19, p. 13.

[1759] Ex. SCE-10, Vol. 2, Ch. IV, Workpaper p. 233.

[1760] Ex. DRA-19, p. 13.

[1761] Ex. SCE-25, Vol. 2, Appendix, p. C-40.

[1762] See 22 RT 3652, Fielder/ SCE.

[1763] Ex. DRA-71, "Working Cash, A Training Seminar by Tom Pulsifer" July 1987.

[1764] Ex. SC-10, Vol. 2, Ch. IV, Workpaper p. 184.

quarterly payments of $24,505,000, and using those hypothetical averaged figures to develop its lag day estimate.

DRA used SCE's actual 2009 quarterly payments of $12,000,000, $12,000,000, $25,000,000, and $49,020,000 to develop DRA's estimate of 75.09 lag days. DRA recommends that the Commission use actual data as it provides a more accurate estimate than using hypothetical averaged figures DRA's forecast is 75.09 lag days for Funded Pension Provisions.[1765]

20.5. Customer Deposits

As in prior SCE GRCs, TURN has taken the lead in addressing the issue of customer deposits as an offset to rate base. DRA recommends the Commission adopt TURN's proposals here as well.

In prior SCE GRCs, the Commission has agreed with TURN that customer deposits should be treated as an offset (i.e., reduction) to rate base.[1766] DRA recommends that the Commission continue with this policy and that it be reflected in the Results of Operations (RO) model to develop the forecast of SCE's 2012 revenue requirement.

From information SCE provided in response to a data request, it appears that SCE has forecasted an annual weighted-average of $206.953 million in customer deposits for 2012.[1767] DRA has applied the $206.953 million as an offset to rate base (similar to how Customer Advances for Construction is reflected as an adjustment to rate base).

To be consistent with prior Commission decisions using customer deposits as a deduction to rate base, SCE should recover, as an expense, the estimated interest it would have to pay to refund the customer deposits. DRA recommends the Commission use a 3-month Commercial Paper rate of 1.76%[1768] and apply that rate to the weighted–average customer deposit estimate of $206.953 million to arrive at a figure of $3.642 million. This is the amount DRA recommends SCE be allowed to recover as an expense in 2012.[1769]

[1765] Ex. DRA-19, p. 14.

[1766] D.09-03-025, pp. 286-287; D.06-05-016, pp. 279-282, and Appendix C, p. C-21; D.04-07-022, pp. 248-249.

[1767] Ex. DRA-19, p. 15, citing DRA-SCE-183-GSD, Q/A 2.

[1768] Ex. DRA-19, p. 15, footnote 35 citing March 2011 IHS Global Insight, U.S. Economic Outlook Financial Markets, Table 1, Interest Rates, Money, and Financial Variables, p. 19.

[1769] Ex. DRA-19, p. 15.

20.6. Rate of Return on Legacy Meters and Mohave Generating Station

20.6.1. Background

SCE filed Application (A.) 07-07-026 seeking authorization of its Advanced Metering Infrastructure (AMI) deployment activities and associated cost recovery mechanism on July 31, 2007.[1770] As a result of A.07-07-026, Decision (D) 08-09-039 resolved that Application, and approved a settlement proposed by SCE and DRA to allow $1.63 billion in ratepayer funding for SCE's proposed Advanced Metering Infrastructure (AMI) Project from 2008 through 2012.[1771] The settlement adopted SCE's proposal by which SCE will recover the costs of deployment through a balancing account mechanism, with the revenue requirement allocated among customer classes according to the proposed distribution allocator SCE proposed in A.07-07-026.[1772]

SCE began deployment of its SmartConnect meter program in 2008 to all metered accounts in its service territory with demands less than 200 kW (approximately 5.3 million meters) and anticipates that its SmartConnect meter program will be fully deployed by the end of 2012.[1773] SCE established the Edison SmartConnect balancing account (ESCBA) to record SmartConnect-related costs and benefits.[1774]

As SCE deploys its SmartConnect meters through its service territory, SCE must retire the replaced legacy electromechanical (legacy) meters. If the legacy meters had not been replaced and retired by SCE's SmartConnect meters, then the legacy meters would continue to remain in service. Decision 08-09-039 does not specifically address the ratemaking for the retired legacy meters. SCE continues to deduct the original cost of the legacy meters from both plant in service balance and the depreciation reserve balance after the meters are retired and removed from useful service. Therefore, the undepreciated balance of the legacy meters is currently being amortized over the estimated remaining life of the legacy meters. The unamortized balance, however, is included as an element of rate base and earning the full authorized rate of return.

[1770] D.08-09-039, p. 5.

[1771] D.08-09-039, p. 2.

[1772] D.08-09-039, p. 13.

[1773] Ex. SCE-4, Vol. 1, p. 1.

[1774] Ex. SCE-4, Vol. 1, p. 1.

In PG&E's TY 2011GRC Application 09-12-020, the ratemaking treatment for legacy meters which are no longer used and useful remained in contention after most of the other GRC issues settled. In its decision resolving the ratemaking treatment of PG&E's legacy meters for the GRC, the Commission declined to "...speculate as to why parties did not choose to litigate this issue in either of PG&E's AMI proceedings." In the GRC decision, the Commission found the issue to be important and relevant, noting that "...the Commission likely did not fully understand and consider the ramifications..." in PG&E's AMI proceedings.[1775]

The circumstances surrounding SCE's retired legacy meters are similar to those surrounding PG&E's AMI proceedings: no party specifically addressed the future ratemaking treatment associated with the retirement of the legacy meters in SCE's AMI proceeding. At issue now is the ratemaking treatment of SCE's legacy meters which are no longer used and useful. DRA recommends that these legacy meters be excluded from rate base and excluded from earning a rate of return.

DRA's recommendation is consistent with prior Commission decisions, as described in D.11-05-018. For instance, in D.84-09-089, the Commission stated:

> Over the years, this Commission has closely adhered to the "used and useful" principle, which requires that utility property be actually in use and providing service in order to be included in the utility's ratebase. We have regularly applied this principle to exclude from ratebase any construction work in progress, and have removed from ratebase plant which has ceased to be used and useful.[1776]

In D.85-08-046, the Commission focused on who should bear the burden of unrecovered costs in the Humboldt Bay plant retirement. In that decision, the Commission stated:

> With respect to PG&E's equity argument, we observe that plants which have exceeded their estimated useful lives have been fully depreciated. Thus, the shareholder already has recovered his entire investment and a fair return on that investment from the ratepayer. The ratepayer who has paid for the entire plant is entitled to receive any additional benefit from the plant's continued operation. In the case of a premature retirement, the ratepayer typically still pays for all of the plant's direct cost even though the plant did not operate as long as was expected. The shareholder recovers his

[1775] D. 11-05-018, mimeo, p. 40.

[1776] D.11-05-018, mimeo, p. 49.

> investment but should not receive any return on the undepreciated plant. This is a fair division of risks and benefits.[1777]

In D.85-12-108, regarding SD&E's proposal to store power plants that could no longer be operated economically, the Commission determined that as to those plants likely to remain retired, there should be a sharing of the burden, stating:

> The specific ratemaking treatment for these plants will essentially follow the suggestion of UCAN. The UCAN position is that the undepreciated balance of the prematurely retired plants be amortized over five years with no return earned. The FEA recommended a longer period – nine years of three rate cases. We find that the UCAN has shown that the two rate case periods or about five years provides an appropriate sharing of the burden between the ratepayers and shareholders.[1778]

In D.92-12-057, the case of the Geysers Unit 15 premature retirement, the Commission relied on the Humboldt Bay plant retirement as a precedent in ruling that PG&E could not offset the shorter life of Unit 15 against other plants having a longer life, using rules of group accounting. The Commission did offer that PG&E could raise the group accounting argument later, if it could make a stronger showing. The Commission also stated, ". . . We once again endorse our longstanding regulatory principle that shareholders should earn a return only on used and useful plant …" PG&E was authorized a four-year amortization for the remaining net plant cost, with no return on the unamortized balance.[1779]

DRA recommends these principles be applied to SCE's legacy meters. SCE's recorded plant balance for the legacy meters as of December 31, 2010 was $321.814 million.[1780] The depreciation reserve for the legacy meters as of December 31, 2010 was $13.115 million.[1781] Therefore, the net plant balance (plant balance less depreciation reserve) on December 31, 2010, was $308.699 million.[1782]

[1777] D.11-05-018, mimeo, pp. 46 and 47.

[1778] D.11-05-018, mimeo, p. 46.

[1779] D.11-05-018, mimeo, p. 47.

[1780] Ex. DRA-10, p. 102 citing SCE's response to DRA-SCE-193-SWC, Q/A 1.

[1781] Ex. DRA-10, p. 102, citing SCE's response to DRA-SCE-193-SWC, Q/A 4.

[1782] Ex. DRA-10, p. 102.

20.6.2. DRA's Primary Recommendation

DRA recommends that the net plant balance of $308.699 million be amortized over six years with no rate of return, resulting in a rate recovery of the undepreciated portion of the legacy meters at six equal amounts of $52.041 million for each year from 2012 to 2017 after the gross up for franchise fees and uncollectibles.[1783]

DRA also recommends that the rate recovery of the undepreciated portion of the legacy meters over the six-year amortization should not receive escalation or attrition increases. This is because the amortization was developed separately from the base margin revenues.

20.6.3. DRA's Alternative Recommendation

If the Commission believes SCE should receive some rate of return on the undepreciated legacy meters, then DRA recommends using an annual interest rate of 4.5 percent over an amortization period of six years beginning in 2012 and ending in 2017. The rate of return of 4.5 percent is the five-year average forecasts (2012 to 2016) of the 5-Year U.S. Treasury Note Yield which closely corresponds to DRA's proposed six year amortization period.[1784] The following discussion highlights past Commission decisions that support a reduced rate of return on the unamortized balance:

- **D.92-08-036** – The Commission adopted a settlement between SCE, SDG&E and DRA which allowed a 48 month amortization of remaining investment in San Onofre Nuclear Generating Station Unit 1 (SONGS 1). After shutdown of SONGS 1, the remaining unamortized investment was allowed to earn a rate of return, which after taxes, was fixed at the then current authorized embedded cost of debt.[1785]
- **D.95-12-063** – Regarding electric industry restructuring, the Commission determined that transition cost recovery for remaining net investment should be at a reduced rate of return. The Commission noted that "Allowing recovery of remaining net investment associated with SONGS 1 plant at the embedded cost of debt was reasonable at the time, given the risks faced by the utilities under the then-current regulatory structure. However, today's decision decreases the risk associated with recovery of remaining net investment (now part of transition costs), due to imposition of a nonbypassable charge on distribution system customers (as described in greater detail below) which decreases utility business risk. We will adopt 90% of the embedded cost of debt as a reasonable rate of return on the equity portion of the net

[1783] Ex. DRA-10, p. 102.

[1784] Ex. DRA-10, p. 103, citing March 2011 IHS Global Insight, U.S. Economic Outlook Financial Markets, Table 1, Interest Rates, Money, and Financial Variables, p. 19.

[1785] D.11-05-018, mimeo, pp. 42 and 43.

book value to reflect the reduced risk. We will set the return on the debt portion of net book value at the embedded cost of debt."[1786]

- **D.97-11-074** – Regarding electric restructuring, the Commission stated, "In allowing the recovery of generation plant-related transition costs, we have, in effect, allowed the utilities to recover costs of plants that may no longer be used and useful in the new competitive marketplace."[1787]
- **D.96-01-011** – Consistent with D.95-12-063, the Commission adopted the same recovery of 90% of the embedded cost of debt as a reasonable rate of return on the equity portion of the net book value regarding Incremental Cost Incentive Pricing (ICIP) pricing for SONGS 2 and 3. The Commission noted, "In D.95-12-063, we propose a general policy for stranded cost recovery. There we decided that while use of debt-return is appropriate for the debt component of a stranded investment, a return of 90% of the debt return is appropriate for the non-debt (i.e., equity) share of the stranded investment...."[1788]

Under DRA's alternate proposal, the net plant balance of $308.699 million would be amortized over 72 months at an annual interest rate of 4.5 percent which yields equal amounts of $4.9 million per month for six years. This results in a rate recovery of the undepreciated portion of the legacy meters at equal amounts of $59.479 million for each year from 2012 to 2017 after the gross up for franchise fees and uncollectibles.[1789]

DRA also recommends that the rate recovery of the undepreciated portion of the legacy meters over the six-year amortization should not receive escalation or attrition increases. This is because the amortization was developed separately from the base margin revenues.

20.7. Rate Base Impact of Sale of Four Corners Generating Station

In developing its 2012 rate base estimate, SCE includes the following items associated with the Four Corners Generating Station:

- $4.174 million in Materials & Supplies (M&S) inventory;[1790]
- $305.798 million in coal fuel costs as part of the fuel lag days determination within working cash capital;[1791] and

[1786] D.11-05-018, mimeo, pp. 43.

[1787] D.11-05-018, mimeo, pp. 43.

[1788] D.11-05-018, mimeo, pp. 43 and 44.

[1789] Ex. DRA-10, pp. 104-105.

[1790] Ex. SCE-10, Vol. 2, Ch. IV, p. 55, Table IV-16.

[1791] Ex. DRA-19, p. 15 citing Workpapers to Ex. SCE-10, Vol. 2, Ch. IV, p. 147.

- $6.843 million in Ad Valorem Taxes (New Mexico) as part of its determination of lag days associated with taxes other than income within working cash capital.[1792]

SCE's forecasted 2012 revenue requirement assumes that Four Corners remains in rate base for the entire calendar year, and therefore earns a return on investment for the entire year.

However, given that SCE expects to sell its share in the Four Corners Generating Station by October 1, 2012,[1793] SCE should not be allowed to earn a return on that investment anytime after that date. Therefore, DRA recommends that all rate base items associated with Four Corners, e.g., the M&S inventory, coal fuel costs, and property (ad valorem) taxes, be removed from rate base beginning October 1, 2012.

DRA also recommends that all rate base items associated with Four Corners be removed from SCE's 2013 and 2014 rate base, and that, when SCE has done so, it should report that fact in its Post Test Year Ratemaking advice letters.

21. Non-Tariffed Products and Services

DRA has no comment on this issue at this time.

22. Depreciation

22.1. Overview

Depreciation is the recovery of the original cost of fixed capital assets less the estimated net salvage over the useful life of the property by means of equitable plan of charges through operating expenses. Depreciation expense is a legitimate cost of service. In ratemaking, recovery of depreciation expense is through a single depreciation rate with components that provides for capital recovery, the cost of removal and salvage. Determination of the level of expense is based on the function of the level of plant balance and of the parameters (net salvage value and service life) that are applied to the gross salvage amount received less the cost of removing the asset.

The Federal Energy Regulatory Commission's (FERC) definition of depreciation is as follows:

[1792] Ex. DRA-19, p. 16, citing Workpapers to Ex. SCE-10, Vol. 2, Ch. IV, p. 224. It is DRA's understanding that only a portion of the $6.843 million is associated with Four Corners.

[1793] Ex. SCE-10, Vol. 2, Ch. IV, p. 44, lines 20-25. By A.10-11-010, SCE presents a "Purchase and Sale Agreement" between SCE and Arizona Public Service, the operator of the Four Corners plant. Under the terms of the agreement, the forecast closing of the sale is October 2012.

> Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, and action of the element, inadequacy, obsolescence, changes in the art, changes in demand and requirements of the public authorities.[1794]

The current depreciation accrual rates for SCE were authorized by the Commission in the utility's TY 2006 GRC Decision. In SCE's last GRC, SCE used the straight-line remaining–life methodology to develop its 2009 TY depreciation accruals rates consistent with the guidelines described in the January 3, 1961 Commission Standard Practice (SP) U-4, Determination of Straight-Line Remaining Life Depreciation Accruals.

For this GRC, SCE requests an increase of approximately $516 million[1795] over the 2009 base year for depreciation and amortization expense in 2012. The proposed rate increase represents a 49% increase over the level authorized and recorded in 2009, and is comprised of the following elements:

Past Deficit in Accumulated Depreciation	$11
Going Forward Depreciation	48
Change in Depreciation Plant Balances	457
Total Annual Depreciation Increase	$516

The first two items, amounting to $59 million of the proposed annual increase, result directly from the updated depreciation study submitted by SCE in this proceeding. The $59 million is the amount of additional revenues SCE intends to recover in rates if the Commission adopts the new net salvage rates SCE proposes for 2012. A portion of the $59 million in additional revenues ($11 million) from increased net salvage rates will be for the recovery of $2.7 billion which SCE claims is the deficit that was the consequence of authorized net salvage rates lagging the calculated (proposed) net salvage over the past years.[1796] A second portion of the $59 million additional revenue ($48 million) relates to embedded revenues that

[1794] 18 Code of Federal Regulation (CFR) Part 101.

[1795] Ex. SCE-10, Vol. 2C, p. 19.

[1796] Ex. SCE-10, Vol. 2C, p. 19.

will be generated from the new rates to ensure a further deficit is avoided on a going forward basis. The last item of the rate increase is the $516 million which is for the recovery of normal depreciation expense resulting from the normal wear and tear of assets based on changes in plant balances between 2009 and 2012.

SCE provided an updated Depreciation Study which incorporates proposed depreciation parameters for net salvage rates and service lives as support for the depreciation and amortization expenses increases SCE proposes for the test year.[1797] The study used the Straight-Line Remaining Life method as prescribed in CPUC Standard Practice U-4.

DRA reviewed SCE's Updated Depreciation Study and the workpapers SCE submitted to support its proposed changes to the company's existing depreciation parameters authorized by the Commission in D.06-05-016. SCE proposes to change the service life depreciation parameters for five accounts from the service lives authorized by the Commission in Decision 09-03-025.[1798] DRA does not dispute SCE's proposals concerning service lives.

For depreciation parameters concerning net salvage rates, however, SCE proposes changes to several accounts which result in significant increases to the accounts from the levels authorized in Decision 09-03-025.[1799] DRA disagrees with all of the changes SCE proposes to net salvage rates. DRA did not conduct a similar analysis, but describes below the policy reasons for proposing that the current net salvage rates adopted in Decision 09-03-025 remain unchanged. Changes to the existing net salvage rates are unwarranted at this time

22.2. Recovery of Original Cost of Fixed Assets

Recovery of the original cost of fixed assets is the primary function of depreciation. The authorized single depreciation rate for an asset provides for the recovery of the elements of capital cost, cost of removal and salvage. Under the current straight line remaining life depreciation accruals method, SCE is allowed to fully recover all of its capital investments through depreciation rates. Although the portion of the depreciation rate responsible for recovery of capital investments is not the focus of the depreciation study SCE submitted in this

[1797] Ex. DRA-17, p. 4, citing SCE Work papers, SCE-10 Results of Operations, Vol.3, Chapter V, p.1-129.

[1798] Ex. SCE-10, Vol.3, p. 21.

[1799] Ex. SCE-10, Vol.3, Table V-25, p. 74.

proceeding, nevertheless, it is worth mentioning because it validates DRA's commitment to ensuring SCE fully recovers its cost of capital investment through depreciation rates.

Therefore, DRA does not object to SCE recovering the depreciation rate component for capital investments because recovery of capital investments is a legitimate cost of service. For 2012, SCE proposes a total increase of $516 million for depreciation expense of which $457 million is based on change in depreciable plant balances. DRA does not object to this aspect of SCE's request, although the DRA figure is based on its own forecast of plant balances.

22.3. Net Salvage Rates

For 2012, SCE proposes to increase negative salvage rates for certain accounts claiming the reserve accounts are currently deficient. In this proceeding, SCE has submitted an updated depreciation study as it did in its last three GRC filings. The updated study serves as the basis for the new parameters of net salvage rates that SCE is proposing for its depreciation rates during the Test Year. SCE's current net salvage rates were authorized in the decision in the company's last GRC, D.09-03-025. In SCE's previous general rate case, the Commission provided significant increases in rates and in accrual of negative salvage beginning in 2006.

Similar to its prior GRCs, the updated depreciation study SCE submitted in this proceeding focuses on the depreciation parameter of net salvage rate (Cost of Removal less Gross Salvage). From the total increase of $516 million SCE proposes for depreciation expense, approximately $59 million is for the recovery of net salvage costs through depreciation rates.[1800] According to SCE, $11 million of the $59 million relates to amortization cost of under-collection in prior years. SCE claims it has a deficit in accumulated depreciation because "recent analyses continue to demonstrate these authorized rates to be inadequate."[1801] In other words, SCE alleges the deficit exists because the past authorized net salvage rates lagged behind SCE's calculated (proposed) net salvage rates. The remaining $48 million SCE seeks is for recovery of net salvage costs on a going forward basis to ensure that under-collection is avoided in the future. The two amounts combined represent about 11.5% of the requested increase in depreciation expense for 2012.

[1800] Ex. SCE-10, Vol.2C, p.19.

[1801] Id., p. 20.

DRA objects to SCE's proposed changes to net salvage rates from those authorized by the Commission in D.09-03-025. Prior to the TY 2009 GRC, the net negative salvage rates[1802] had been in effect since the TY 2006 GRC. SCE's rates were increased in the TY 2006 GRC. In the TY 2003 GRC, the Commission did not modify the negative salvage rates, leaving in place the existing rates at the time. DRA's recommendation in this GRC is essentially consistent with the Commission's decision in the TY 2003 GRC. Changes to the net salvage rates are unwarranted at this time. Instead, for the reasons stated below, DRA recommends that the net salvage rates for all assets remain unchanged from the levels authorized by the Commission in D.06-05-016.[1803]

22.4. Calculated and Recorded Depreciation Parameters

SCE claims to have under-collected its depreciation expense by approximately $2.7 billion primarily because the authorized (recorded) depreciation expense for net salvage lagged the calculated (theoretical) costs in past years. SCE states:

> "At year-end 2009 accumulated depreciation was $2.7 billion below correct levels of accumulated depreciation."[1804]

The variance between the recorded (authorized) and the calculated (proposed) depreciation expense can be referred to as the "theoretical reserve imbalance." The assumptions underlying SCE's calculation of the reserve imbalance are based on certain assumptions about the distribution by ages of existing property, the service lives, and net salvage parameters which require judgment and subjectivity. Calculated (proposed) and recorded (authorized) depreciation parameters may differ and a theoretical imbalance is not an unusual phenomenon in depreciation for regulatory considerations. Sometimes assets are retired before the end of their original service lives, resulting, occasionally, in a positive imbalance. Sometimes, the imbalance is negative. When such situations arise, the Commission reviews them on a case by case basis, and subsequently adopts the appropriate recovery remedy as necessary.[1805]

[1802] Net negative salvage results when it costs more to remove and dispose of an asset than the asset is worth.

[1803] Ex. DRA-17, p. 7.

[1804] Ex. SCE-10, Vol. 3 –Depreciation Study, p. 12.

[1805] Ex. DRA-17, pp. 9-10.

Although theoretical reserves studies may be useful tools for evaluating the adequacy of depreciation accruals authorized in rates, the resulting calculated reserve imbalance neither increases SCE's risks nor endangers its ability to recover the company's capital investments, which is the primary function of depreciation. The existing depreciation rates provide for full recovery of capital investments plus adequate funding for net salvage. Recovery of the original cost of capital through depreciation expense is a legitimate cost of service and, as indicated earlier, DRA does not object to SCE recovering the costs in depreciation rates.

While it is important that the Commission provide utilities adequate funding in current rates for current and future cost of removal, caution must be exercised to ensure that current ratepayers are not overburdened or overtaxed for future costs that may or may not occur. Only when an asset has lived its useful life will the true depreciation parameters be known. Retaining the existing net salvage rates creates no adverse impact to shareholders or the utility since the utility is entitled to ultimately recover and accrue the ultimate net salvage costs.

In the end, SCE and its shareholders are never at risk for cost of removal and are always made whole whether or not the final cost of removal exceeds or is below the amount accrued in the reserve account. Regardless of the nature of the imbalance, the utility is not subjected to an increased risk of recovering either its capital investment or cost of removal through depreciation expense or amortization expense.

22.5. Future Cost of Removal

SCE has already collected $2.634 billion in rates that it has yet to spend for future cost of removal.[1806] SCE, however, seeks to focus the Commission's attention on the purported $2.7 billion deficit.

In 2001, the Financial Accounting Standard Board (FASB) issued Financial Accounting Standard Number (FAS) 143 which addresses Asset Retirement Obligations (AROs) associated with long-lived plant on which the company has legal obligations. The pronouncement also addresses the potential regulatory liability resulting from the cost of removal and dismantling factors (net salvage cost) in depreciation rates that public utilities have included in rates in the past. FERC identified these amounts as non-legal AROs. Unlike the legal AROs, utilities do not have actual legal obligations and liabilities to incur non-legal AROs in the future.

[1806] Ex. DRA-17, p. 10, citing DRA-SCE-MRK-246, Q/A. 1.

In the course of preparing its testimony, DRA asked SCE to provide the cumulative end of year balances for 2004 through 2010 of the amounts that SCE collected in rates to pre-fund future cost of removal, but had yet to spend, excluding legal ARO obligations. In a response to DRA's data request,[1807] SCE identified the non-legal AROs amount to be approximately $2.6 billion. This amount represents the non-legal AROs SCE has collected in rates for future cost of removal that the company has yet to spend and has no legal obligation to incur. Implicitly, SCE would have collected approximately $5.3 billion (the $2.6 billion amount already collected yet unspent plus the calculated imbalance of $2.7 billion) in rates for non-legal ARO assets had the Commission approved the net salvage rates requested in prior GRCs.

DRA also asked SCE to provide a comparison of SCE's depreciation expenses, as computed for ratemaking purposes and as computed for tax purposes applying FAS 143 treatment of certain asset retirement obligations. SCE refused to provide the information saying that it did not have the information requested and that, "SCE is not required to perform studies in response to data requests."[1808]

For the 3-year GRC cycle, SCE requests a cumulative increase in revenues of approximately $4.1 billion. Adopting this increase would result in a significant increase to existing rates which are currently quite high.[1809] SCE says its proposal follows the Commission's Standard Practice U-4, dated January 4, 1961.[1810]

In fact, SCE seems to have disregarded one significant directive in Standard Practice U-4. Standard Practice U-4 provides the following as a general guideline:

> **Analysis of Reasonableness of Results**
>
> In the final analysis, a determination of depreciation accruals is based on engineering judgment of anticipated future conditions. It is therefore well to apply some test of reasonableness to the final results..... As a [] test of reasonableness, it is well to compare the results determined for rate-fixing purposes with those reported for income tax purposes. In particular, the depreciation reserve carried

[1807] Ex. DRA-17, p. 11 citing DRA-SCE-MRK-246 Q/A. 1.

[1808] Ex. DRA-76.

[1809] Ex. DRA-17, p. 11.

[1810] Ex., SCE-10, Vol. 3, p. 8.

> on the books as compared with the depreciation reserve carried for income tax purposes should be noted.[1811]

It is unfortunate that SCE chose not to perform the test recommended in Standard Practice U-4. In the end, this leaves the Commission with no way to independently verify the reasonableness of SCE's proposal. SCE's failure to provide the comparison of depreciation accruals recommended in Standard Practice U- 4 may be further evidence of the ***un***reasonableness of SCE's request.

SCE's rateapayers are already being harmed by the current economic downturn which has resulted in the loss of jobs and homes in the areas SCE serves. Given the sizable TY 2012 rate increase requested by SCE, and the substantial amounts SCE has already collected in rates for negative salvage that have yet to be spent, the Commission should be receptive to those areas in which the rate increase can be mitigated. This is one such area where the requested rate increase may be mitigated with no risk or adverse impact to the utility and its shareholders.[1812]

22.6. SCE's Current Net Salvage Rates As Compared to Other Utilities

Compared to SDG&E and PG&E, the other major electric utilities in California, SCE already has some of the highest negative salvage rates.[1813] Increasing SCE's net salvage rates from their authorized levels will further increase the disparity between SCE and the other utilities. For example, it costs PG&E ratepayers eighty cents to retire one dollar of investments in distribution poles.[1814] For SDG&E ratepayers, it costs one dollar. But it costs SCE ratepayers $1.90 to retire the same $1 investment in poles. Under SCE's proposal in this GRC, it will cost SCE ratepayers $2.00 in negative salvage to retire $1 of investment in poles.

The utilities have each argued in the past that because of differences in accounting practices, maintenance practices, and on how they account for salvage costs, differences will always exist between their net salvage rates. Regardless of what various factors might be contributing to the disparity between the utilities, some level of consistency should be expected

---

[1811] Standard Practice U-4, Chapter 9, General Considerations and Staff Procedures, p. 45.

[1812] Ex. DRA-17, p. 11.

[1813] There are even greater disparities when the California utilities are compared to out of state utilities or to industry-wide averages. Even though it is difficult to compare California utilities and the out of state utilities, the authorized net salvage rates for California utilities are much higher than the negative salvage rates authorized for out of state utilities. (EEI-AGA Industry Averages) Ex. DRA-17, p. 11, footnote 12.

[1814] Ex. DRA-17, p. 12, Table 17-3, Account 364.

even if it involves implementing a special ratemaking mechanism to make negative salvage rates more comparable.

In past GRC proceedings, DRA has recommended, and the Commission has adopted, a capping mechanism.[1815] Capping the authorized net salvage rates for certain accounts may mitigate the impact of an increase to ratepayers. By retaining SCE's negative salvage rates at the 2009 adopted levels, there is at least a chance that the disparity between SCE and the other California energy utilities will not increase further.

22.7. SCE Already Collects Sufficient Revenues

Under the currently authorized negative salvage rates for SCE, the company collects sufficient amounts in rates to fund the current cost of removal plus additional amounts that go into reserve to fund future cost of removal. SCE claims that the additional amounts that go into the reserve are insufficient; however there is no need to change the salvage rates now, as long as the contributions to the reserve remain sufficiently positive.

Between 2005 and 2010, SCE collected approximately $1.5 billon in rates from customers for cost of removal and incurred actual expenditures of approximately $0.95 billion during the six year period.[1816] This means that about two- thirds of the amount collected in rates for cost of removal was actually spent by SCE for removal activities, with the remaining one-third going towards ratepayer's contribution (accrual) to pre-fund future cost of removal. The 33% margin embedded in the current net salvage rates for the purpose of funding future cost of removal is adequate and should be retained during this rate case cycle.

Although cost of removal is an appropriate cost of doing business, the Commission should ensure that today's ratepayers are not paying more than their equitable share of the costs. SCE currently accrues negative net salvage at a level sufficiently higher than the annual recorded cost of removal that SCE will not be short of funds to cover its removal or net salvage costs in the foreseeable future even without the requested increase. Therefore, DRA is recommending that a conservative approach be adopted in addressing this issue, which in this case is to retain the negative salvage rates adopted in D.06-05-016. In that decision, the Commission expressed concerns over the increasing future cost of removal, stating:

[1815] D. 06-05-016, mimeo, p. 209; D. 07-03-044, p. 209, adopting settlement.

[1816] Ex. DRA-17, p. 14, Table 17-4.

> [W]hen the projected net salvage becomes substantial, in some cases substantially exceeding the original cost of the associated plant, we also have a responsibility to determine whether past practices are consistent with producing the most reliable net salvage projections.[1817]

Given these concerns, therefore, it is not surprising the Commission adopted a conservative approach in determining what the appropriate net salvage rates should be for SCE. Specifically the Commission stated as follows:

> We do note that despite the distribution pole situation described above, by nature of the established methodology where SCE is paying off current removal costs, while rates are being collected to fund future costs that are much higher than current costs, the non-ARO balance, which is already over $2 billion, will continue to grow. At no time in the foreseeable future will SCE be short of funds to cover its removal or net salvage costs. In that regard it is not urgent that this issue be definitively decided at this time. Due to the large dollars at stake, and the wide range of possibilities, we prefer to be conservative in adjusting net salvage ratios, rates or accruals.[1818]

A conservative approach that freezes the net salvage rates at the 2009 adopted levels is the most appropriate for SCE in this case. SCE's next rate case filing will be in three years. At that time, SCE's net salvage rates can be reviewed for a determination as to whether the rates should be adjusted. Recovery for net salvage is not a critical requirement that impacts the utility's ability to provide safe and reliable services to its customers. This is one area where the requested rate increase may be mitigated with no risk or adverse impact to the utility and its shareholders.

22.8. SCE Supposed "Reserve Imbalance"

As part of its review of SCE's proposal, DRA asked SCE on numerous occasions for documentation regarding its calculations of its supposed reserve imbalance.[1819] Since SCE complained that DRA's earlier data requests for working spreadsheets were burdensome, DRA asked SCE to provide working spread sheets for just one account, Account 364, Poles. SCE replied that would still be burdensome. SCE's justification was that the information DRA was

---

[1817] D.06-05-016, mimeo, p. 206.

[1818] D.06-05-016, Pg. 209.

[1819] Ex. DRA-17, p. 15, footnote 19 citing DRA-SCE-227-MRK, DRA-SCE-235-MRK, DRA-SCE-250-MRK, DRA-SCE-251-MRK, DRA-SCE-258-MRK.

asking for came from the accounting system. When DRA requested written documentation[1820] as to how SCE calculated its reserve imbalance, SCE did not provide the requested specific information.

SCE attempts to justify its proposal to change net salvage rates partly on the basis of a purportedly large calculated depreciation imbalance of $2.7 billion, but refuses to provide documentation to show how its accounting system is used in the calculation of this supposed imbalance. The utility collects ratepayer money to provide rate case materials, including documentation as required by the Commission. To allow the Commission to understand how the utility calculates its recorded numbers *in practice*, not just in theory, the utility ought to be able to provide the documentation. If SCE truly maintains that providing a working spreadsheet for just one account is too burdensome, then it should be prepared to offer a constructive alternative.[1821] Since SCE has not done so, SCE's lack of documentation to substantiate its argument is reason enough to deny this request to change salvage rates.[1822]

22.9. Third Party Reimbursements

22.9.1. DRA's Proposals for Third Party Reimbursements Accounting

Third Party Reimbursements fall into four categories: (1) insurance reimbursements which are paid to compensate SCE for loss or destruction of property, (2) relocation reimbursements which are paid to compensate SCE when it is paid to relocate facilities, (3) added facility reimbursements paid by customers for special facilities, and (4) interconnection facility reimbursements to deliver or receive power from a reseller or producer of energy. When SCE receives a Third Party Reimbursement, a portion is credited to the depreciation reserve, but the majority is credited to the gross plant account. However the FERC Uniform System of Accounts (USofA) provides that the entire Third Party Reimbursement should be credited to the depreciation reserve,[1823] explicitly stating, in fact, that gross salvage and Third Party Reimbursements be credited to depreciation reserve.

NARUC[1824] defines gross salvage as follows,

[1820] Ex. DRA-17, p. 15, footnote 20.

[1821] D.09-03-025, mimeo., at p. 315

[1822] Ex. DRA-17, p. 16.

[1823] Ex. DRA-17, p. 16, footnote 22.

[1824] Ex. DRA-17, p. 17, citing NARUC "Public Utility Practice", August 1996, page 320, Glossary.

> "**Gross salvage:** The amount recorded for the property retired due to the sale, **reimbursement**, or reuse of the property."

It seems clear from the above statements that FERC and NARUC consider that Third Party Reimbursements should be credited to depreciation reserve. SCE's own Depreciation Study[1825] contains language that would seem to confirm that:

> **Gross Salvage:** The salvage value of used equipment (e.g. power operated equipment, meters, etc.) and the scrap value of used equipment (e.g. copper conductor) are the most readily recognizable forms of salvage. Other salvage values **include third-party reimbursements** and the value of reusable equipment placed back into utility inventory under the location-life accounting technique.

SCE's Depreciation Study also includes the following.[1826]

> The majority of the gross salvage recorded to transmission and distribution line accounts (e.g., poles, conduit, and conductor) has come from reimbursed retirement activity, as opposed to scrap value. Joint Pole Credits recorded to accumulated depreciation are proceeds from joint owners for their share in the removal costs for poles being replaced. These credit amounts are also included as gross salvage in the salvage analysis.

Yet, in actual practice, SCE credits only a small fraction of Third Party Reimbursements to depreciation reserve. For example, in 2010 SCE received about $58 million in Third Party Reimbursement funds, and allocated only about $8.8 million to accumulated depreciation reserve.[1827]

In Rebuttal, SCE argues that DRA's citations to FERC USofA, and NARUC statements are "...pinpointed to single sources, ignore other provisions in the same sources, and taken out of context."[1828] SCE goes on to say that, "[c]ontrary to DRA's assertion, the FERC USofA clearly provides that contributions for construction related costs should be recorded as an offset to Plant-In-Service."[1829]

The FERC USofA reference DRA includes in its testimony and to which SCE objects, is the following.

[1825] Ex.SCE-10, Vol. 3, Chapter 5, p. 64.

[1826] Ex. SCE-10, Vol. 3, Chapter 5, p. 71-72.

[1827] Ex. DRA-17, p. 18.

[1828] Ex. SCE-25, Vol. 3, p. 12.

[1829] Ex. SCE-25, vol. 3, p. 12.

> At the time of retirement of depreciable electric utility plant, this account shall be charged with the book cost o f the property retired and the cost of removal and shall be credited with the salvage value and any other amounts recovered, such as insurance.[1830]

DRA's reference to the FERC USofA is taken from "Section 108: Accumulated Provision for Depreciation of Electric Utility Plant (Major only)."

SCE, on the other hand, would have the Commission rely instead on a quotation taken from " 2: *Electric Plant To Be Recorded At Cost*" that appears in a general category devoted to construction of new plant. Section 3 is entitled "*Components of construction cost*," and Section 4 is titled *"Overhead Construction Costs."* It, thus, seems highly unlikely that the term "contributions" in the paragraph SCE quotes refers to Third Party Reimbursements for replacement of assets. Rather, the term contributions must refer to "Contributions in Aid of Construction," which are received in contexts other than Third Party Reimbursements.

DRA's citation, on the other hand, is in exactly the section, Accumulated Provision for Depreciation, that is relevant for the treatment of Third Party Reimbursements. DRA's citation, though short, omits no relevant material. SCE's complaint that DRA's citations regarding Third Party Reimbursements are "pinpointed to single sources, ignore other provisions in the same source, and taken out of context" is applicable to SCE, not to DRA.

SCE's current accounting treatment of Third Party Reimbursements has followed a decidedly murky path. In 2003, SCE introduced an accounting change regarding Third Party Reimbursements, which it described as follows in its 2006 GRC testimony:[1831]

> In 2003, SCE revised its accounting procedures for reimbursements to better comport with the FERC USOA. SCE now records third-party reimbursements for construction costs as Contributions In Aid of Construction (CIAC) offsets to plant; and reimbursements for removal cost and gross salvage as offsets to net salvage in accumulated depreciation. The revision to SCE's reimbursement accounting procedure, however, does not affect the total rate base or depreciation expense. Whether or not a reimbursement is accounted for as a credit to plant (*i.e.*, a decrease to plant balance) or as a credit to accumulated depreciation (*i.e.*, an increase to accumulated depreciation balance), has no impact on the net plant balance included in rate base or recovered through depreciation.

[1830] 18 CFR, Ch. 1, Pt. 101 – 108, Paragraph B.

[1831] Ex. DRA-17, p. 18, citing SCE TY 2006 GRC, SCE Testimony SCE-08 Vol. 3.

SCE's description of its revision of accounting procedures for third-party reimbursements is opaque. However, SCE's change in accounting regarding Third Party Reimbursements was characterized as follows by William M. Stout, who wrote Rebuttal testimony for SCE in that same rate case:[1832]

> The change made by SCE was to assign as gross salvage the portion of the monies received that reimbursed the Company for its net cost of retiring the old asset and to assign as a contribution in aid of construction the portion of the monies received that reimbursed the Company for the construction of the replacement asset. Previously, SCE also assigned monies to gross salvage for the net book value of the asset being retired. Such amounts would now effectively be considered a reimbursement for the amount expended on the new plant.

Mr. Stout, at least, is clear, if one understands that all Third Party Reimbursement moneys assigned to gross salvage in Mr. Stout's discussion are **in addition** to the original gross salvage amount. According to Mr. Stout, SCE's final recorded gross salvage for Third Party Reimbursement retirements was an amount equal to the cost of removal (net cost of retiring the asset plus the original gross salvage for the asset) after 2003, whereas previously SCE had recorded for Third Party Reimbursement retirements an amount equal to the cost of removal plus the net book value of the asset being retired.

DRA's 2006 GRC testimony on this subject was as follows:[1833]

> The recorded net salvage dollars that SCE used in its net salvage analysis do not appear to include all of the salvage dollars that the company actually received from third-party reimbursed retirements. According to SCE's representation in its last GRC, revenues from reimbursed retirements were treated like salvage with the full amount being assigned to gross salvage, thereby reducing net salvage. Booking the full amount to gross salvage would be the proper accounting for reimbursed retirement except that TURN's witness in SCE's last GRC disagreed with SCE's claim by alleging incorrect accounting for cost of removal. Based on its analysis of net salvage in this proceeding, ORA questions SCE's assertion that the full amount received from reimbursed retirement was actually booked to gross salvage. It is possible that

---

[1832] Ex. DRA-17, p. 19 citing Rebuttal Testimony of William M. Stout, P.E." On Depreciation Issues In Southern California Edison, 2006 General Rate Case", California Public Utilities Commission, A.04-12-014, May 2005.

[1833] Ex. DRA -17, p. 20, citing A.04-12-014, Report on the Results of Operations for Southern California Edison Company General Rate Case Test Year 2006, Volume 2, p. 14-20.

> SCE's claim of an accounting change for third-party reimbursed retirement in 2003 is tactically designed to deflect concerns related to accounting for such transactions in the past. Trying to justify why the accounting change was necessary, SCE argues that the new accounting treatment for third-party reimbursed retirement does not affect total rate base. ORA agrees that the change does not affect total rate base, however, the change does affect the accrual rate for net salvage because gross salvage becomes understated since only a portion, and not all of reimbursement is now accounted for as gross salvage. SCE also states that the change was more in-line with the guidelines provided in the Uniform System of Accounts (USoA) and NARUC. With the change, only some of the revenues from reimbursement retirements are now assigned to gross salvage, with the remainder being allocated as a reduction to the replacement costs of the new asset. ORA does not agree with SCE's interpretation of NARUC's guideline on how reimbursed retirement should be treated.

In June 2008, SCE introduced yet another accounting change regarding Third Party Reimbursements. SCE did not mention this 2008 accounting change in its TY 2009 GRC testimony, however.[1834]

DRA's previous comments on SCE's *2003* change in accounting for Third Party Reimbursements are, thus, all the more cogent given SCE's *2008* change in accounting, and support a skeptical attitude towards SCE's motivation for its latest accounting change. Whatever the motivation, SCE's constant accounting changes make it difficult, if not impossible, for the Commission to determine if there is any merit to SCE's claim that these its actions have no "cost of service impact."[1835]

Apparently, SCE plans to change its Third Party Reimbursement accounting yet again, this time "... to revert back to the pre-2008 treatment of Third Party Reimbursements which will be consistent for all years."[1836] DRA recommends that the Commission make this accounting change part of its formal Orders in its final decision in this GRC. Specifically, SCE should be required to change its accounting so that all Third Party Reimbursements are assigned to gross salvage, consistent with NARUC's definition of gross salvage, consistent with FERC's definition

---

[1834] Ex. DRA-17, p. 19; 23 RT 3936, Bennett / SCE.

[1835] 23 RT 3936, lines 18-28, Bennett/ SCE.

[1836] 23 RT 3937, lines15-21, Bennett/ SCE.

of Accumulated Provision for Depreciation of Electric Utility Plant, and consistent with SCE's own treatment of gross salvage in computing net salvage rates.

22.9.2. Accounting for Third Party Reimbursements In Other Jurisdictions

In its Rebuttal testimony, SCE agues that "[o]ther state commissions have rejected proposals similar to TURN's and DRA's to include reimbursed construction costs in net salvage."[1837]

One of SCE's two citations is a 1986 case of the Maryland Public Service Commission. More recently, however, the Public Service Commission (PSC) of Maryland instituted two proceedings: cases 9103 and 9096. For case 9103, the Maryland PSC issued Order No. 83139 on February 5, 2010, in which Washington Gas Light Company was required to credit all Third Party Reimbursements to gross salvage.[1838] For case 9096, Maryland PSC issued Order No. 83310 on May 4, 2010, in which Baltimore Gas and Electric Company was required to credit all Third Party Reimbursements to gross salvage. The Maryland PSC concluded that "...the inclusion of TPRs in salvage would result in more accurate depreciation rates."[1839]

22.9.3. SCE's "Proper" Reimbursement Accounting Error

In SCE's Rebuttal, SCE includes a scenario, apparently intended to illustrate "Proper Reimbursement Accounting." According to SCE, "[t]his scenario assumes that the utility perpetually replaces two assets with an installation cost (labor and material) of $10,000 each and a retirement cost (net salvage) of $5,000 each. Also assume that one of the two assets is fully reimbursed with third-party funds (at total of $15,000 tor installation and retirement costs.)"[1840]

A footnote explains that, "[t]his is similar to examining SCE's property on a mass scale in which a certain portion of retirements can reasonable be expected to experience third-party reimbursement s for replacement activity."[1841]

[1837] Ex. SCE-25, Vol. 3, p. 13.

[1838] In the Matter of the Application of Washington Gas Light Company for Approval of Changes in Depreciation Rates (February 5, 2010) Order No. 83139, Case No. 9103 (http://www.psc.state.md.us/Intranet/info/applications_new.cfm).

[1839] In the Matter of the Application of Baltimore Gas and Electric Company for Approval of Changes in Depreciation Rates (May 4, 2010) Order No. 83310, mimeo, p. 13, Case No. 9096.

[1840] Ex. SCE-25, Vol. 3, p. 27.

[1841] Id.

SCE presents two tables illustrating its reimbursement accounting -Table III-9 on page 28 and a full detailed table on page C-5 of Appendix C. Table III-9 unaccountably assigns a value of $10,000 to retirements to the first line. This is in contradiction of the scenario it presented with two assets valued $10,000 being retired. This leads to a miscalculation of SCE's salvage rate which is further magnified in the corresponding detailed table on C-5 of Appendix C. The table on C-5 of Appendix C also suffers from miscalculating column L, the ending balance for accumulated depreciation. The given formula, L=I+K-D+F does not agree with the numbers involved. This is seen, for instance, in year 5, when L=0, I=12,000, K=3,000, D=10,000, and F=-10,000. Presumably, the formula is missing the reimbursement amount of 5,000.

DRA recommends that the Commission place no reliance on this Rebuttal testimony.

23. Jurisdictional Cost Separation

DRA has no comment on this issue at this time, beyond what DRA has set forth in Section 5.18 of this Brief, above, and in the other affected areas.

24. Other Results of Operations Issues

DRA has no comment on this issue at this time, beyond what DRA has noted in other ares of this Brief.

25. Audit

As part of its review of SCE's GRC Application, DRA conducted an examination of SCE's financial records in accordance with the authority and mandates set forth in the Public Utilities Code Sections 314, 314.5, and 309.5. This examination does not mirror an audit conducted in accordance with generally accepted auditing standards and accounting principles. Instead, the general objective of DRA's examination is to ensure that the interests of ratepayers are reasonably protected, and that the Applicant's financial records, on which the GRC is based, were reasonable and proper for ratemaking purposes under established Commission rules and regulations.

Requested revenue requirements in general rate cases typically are based on test year forecasts that stem from recorded financial statement data (referred to as the 2009 base year in this filing). DRA's examination addressed SCE's recorded historical data, used in connection with forecasting SCE's revenue requirement.

Based on DRA's examination, DRA recommends the removal of the Operations and Maintenance (O&M) and Administrative and General (A&G) amounts for costs associated with

SCE's WISER[1842] Program, GIS Pilot Project, Catalina Fire, Navajo Litigation, Tax Services and ACE Awards.[1843]

25.1. WISER Program

DRA recommends the removal of $6.156 million in 2009 costs related to SCE's WISER Program. SCE described its WISER program as a "collection of initiatives focused on the review and improvement of our core business processes."[1844] SCE says its WISER program is being managed by the Transmission and Distribution Business Unit (TDBU) Business Process and Technology Integration group.

DRA asked SCE to provide information about the total cost of the WISER program, whether the services were of a one-time nature, whether any costs were removed for forecasting purposes, and why SCE considered this an item that should be included for ratemaking purposes. SCE's response, in part, was that it "...developed its 2010 – 2014 forecasts on a project-by-project, year-by-year basis... and did not utilize recorded costs in its development of the WISER forecast."[1845] According to SCE, "[t]he services that Bain consultants are providing in support of WISER are not expected to continue beyond 2011."[1846]

DRA recommends removing the WISER costs from the base year for purposes of forecasting O&M costs. Despite SCE's assertion that it *may* engage consultants and/or other contractors for support services, SCE has provided no evidence as to the type of future needs. SCE's own uncertainty – it may engage consultants, but then again, it may not – is reason enough to conclude this is not a recurring cost and remove it from the 2009 base year.

25.2. GIS Pilot Project

DRA recommends removal of $1.367 million in 2009 costs related to a Geographical Information System (GIS) that SCE describes as a "pilot project" recorded in FERC Account 588.270.[1847] DRA inquired as to the types of services performed, the total cost of the program,

---

[1842] Wires Investment Strategy Efficiency Review.

[1843] The total dollar amount that DRA recommends be removed is set out in Ex. DRA-22-C, as corrected during the evidentiary hearings on August 24, 2011. *See* 22 RT 3720-3721, Waterworth/ DRA.

[1844] Ex. SCE-3, Vol. 5, p. 39.

[1845] Ex.DRA-22, page 11 citing DRA-SCE-AUDIT-LMW-15, Supplemental 02-Group 2.1, Q. 1b.

[1846] Ex.DRA-22, page 11 citing DRA-SCE-AUDIT-LMW-15, Supplemental 02-Group 2.1, Q. 1d.

[1847] Ex. DRA-22, p. 12.

whether the services were of a one-time nature, whether any costs were removed for forecasting purposes, and why SCE considered this an item that should be included for ratemaking purposes. In one response to DRA's questions, SCE said that the "pilot" was a "proof of concept" to test what was possible in regards to data conversion, filed verification and software tools." None of SCE's responses showed this to be a recurring cost. In fact, in another response, SCE described the project as "unique."[1848]

SCE failed to provide sufficient proof this project is of a recurring nature or identify a similar project as its replacement. These costs should be removed for forecasting purposes.

25.3. Catalina Fire

For 2009, DRA recommends that the uncollectible portion of Catalina fire damage costs recorded in FERC Acct. 583.281[1849] be removed for ratemaking purposes, and any associated claims reserve impact (FERC Acct. 925) be removed as well.

According to data request responses SCE provided:

> The large increase in write-offs was the result of the $5.0 million uncollectible portion of the Catalina fire claim. In the 2012 GRC forecast, write-off expenses are captured under FERC Account 583.281 and the five-year average method was selected for the forecast analysis. This method was chosen due to the fluctuation of costs from 2005 to 2009...
>
> For Claims Reserves (FERC Account 925), the budget-based method was selected for the forecast. Although costs in this activity have shown fluctuation from year to year, it was necessary to review the potential liability exposure for the large fires which occurred during the recorded 2005-2009 years, and to apply the recently implemented insurance coverage structure to them, creating a "back-cast." The four-year average method was then applied to the adjusted historical "back-cast" data of 2005-2009 to estimate the test year 2012 forecast."[1850]
>
> Of the $5 million associated with the uncollectible portion of the Catalina fire, $2.2977 million was included in the 2012 GRC. The

[1848] Ex. DRA-22, p. 12 citing DRA-SCE-AUDIT-LMW-15 Supplemental 02-Group 2.1, Q.2b.

[1849] In Rebuttal, SCE says, "[t]he updated amount for the Catalina Island fire is $3.298 million. $2.298 million was provided in response to Data Request DRA-SCE-AUDIT-LMW-015, Supplemental 01, Q. 2a plus $1.000 million as provided in the response to TURN-SCE-33, Q. 4a. Ex. SCE-27, p. 13, footnote 14.

[1850] DRA-SCE-AUDIT-LMW-15, Q.8.

> remainder of the $5 million was assigned to the water and gas parts of Catalina.[1851]

DRA recommends removing these costs from the 2009 base year. There is no reason to assume that another equally devastating fire is likely to damage Catalina or SCE's property on Catalina in this GRC period. Including extraordinarily large historic fire costs in a forecast, without considering other factors, such as the likelihood of recurrence, forecasted drought conditions, new tree trimming rules, or the fire's cause does not reflect normal expected test year conditions. DRA recommends that the Catalina fire costs be removed.

25.4. Navajo Nation Royalty Litigation

DRA recommends the removal of all costs related to the Navajo Nation royalty litigation that arose when the Mohave Generating Station, a plant in which SCE owned a 56% share, was in operation. These costs include legal fees from Account 923 and any associated claims reserve impact from Claims Reserve Account 925.[1852]

SCE describes the background to this litigation in its Rebuttal testimony.[1853] The Mohave Generating Station was a coal-fired power plant located in Nevada, which ceased operations in December 2005. As SCE describes the background, before the plant was shut down, Mohave received all of its coal supply from a mine operated by Peabody Western Coal Company located on reservation lands of the Navajo Nation and the Hopi Tribe. In 1999, the Navajo Nation (joined later by the Hopi Tribe) sued Peabody and SCE along with SCE's co-owner, Salt River Project Agricultural Improvement and Power District. The original complaint asserted claims against SCE and the other defendants for, among other things, violations of the federal Racketeer Influenced and Corrupt Organizations (RICO) statutes, interference with fiduciary duties and contractual relations, fraudulent misrepresentation by non-disclosure, and various contract-related claims. After a delay of several years, the Navajo Nation filed an amended complain that omits the RICO claim. Parties are engaged in mediation.

[1851] DRA-SCE-AUDIT-LMW-15 Supplemental 01, Q.2a.

[1852] Ex. DRA-22C contains the 56% share of the litigation costs that is SCE's share pursuant to its 56% ownership share in the Mohave Generating Station. Ex. DRA-12C included a different amount based on a data request response received from SCE. DRA agrees that the figure for Navajo Litigation costs in DRA-22C is the figure that should be used. (23 RT 3877-3879, Bower/ DRA.).

[1853] Ex. SCE-27, p. 17.

Given the totality of these circumstances, DRA considers this case and these costs to be unique.[1854] In its Rebuttal, SCE describes DRA's recommended removal of the Navajo Nation litigation costs as a "formulation" that, "...for a particular litigation matter to be properly included in a forecast, there must be a strong likelihood that SCE will face additional litigation with the same subject matter, parties and allegations."[1855] SCE then goes on to refer to the Commission's decision in SCE's 2003 GRC in which the Commission held that the proper inquiry is whether the costs are "...nonetheless representative of future litigation costs."[1856]

SCE mischaracterizes DRA's testimony. In fact, DRA's testimony does just what the Commission's decision says it should do. DRA asked SCE to show how the Navajo Nation litigation costs are indeed representative of future litigation costs, and all SCE has offered is that, "[o]ver the course of a successive period of years, various existing matters can be expected to terminate, only to be replaced by an assortment of new, and often even more challenging matters...."[1857]

As to SCE forecast claims reserves amount, DRA recommended in its testimony that any impact on that reserve associated with the Navajo Litigation and the Happy Camp fire be removed.[1858] DRA noted in its testimony that SCE refused to provide DRA information under attorney-client privilege.

While that is certainly SCE's right to claim the attorney client privilege, it is also DRA's right, and, in fact, responsibility, to inquire into the reasonableness of SCE's cost forecasts. As in the last GRC, where a similar issue arose, DRA does not challenge SCE's assertion of attorney-client privilege; the issue is whether SCE met its burden of proof. "Since SCE chose to assert its claim of attorney-client privilege, it must meet its burden of proof in some other way."[1859]

[1854] Ex. DRA-22, p. 14.

[1855] Ex. SCE-27, p. 17.

[1856] D.04-07-022, p. 168.

[1857] Ex. DRA-17, p. 15 citing DRA-SCE-AUDIT-LMW-16, Q. 7b.

[1858] In its prepared testimony, DRA also recommended that costs associated with the SONGS Security Guard litigation be removed, but DRA has since withdrawn that testimony as to that litigation. (22 RT 3721, Waterworth/ DRA.).

[1859] D.09-03-0258.

SCE has not done so. Although SCE describes in detail its reasons for not providing DRA, or the Commission, with the information DRA asked for, it provides nothing at all that would allow DRA, or the Commission to evaluate the reasonableness of SCE's forecast. DRA's recommendation should be adopted.

25.5. Happy Camp Fire

DRA proposes audit adjustments to remove any historic claims reserve or settlement impact related to the Happy Camp fire. As discussed above, DRA considers fires unpredictable and extraordinary.

In Rebuttal, SCE says, "DRA's assertion that fires are unusual, non-recurring and infrequent is incorrect." In support of this, SCE cites to data from the US. Forest Service's National Fire and Aviation Management web site that large fires burned between 118,535 and 337,890 acres per year from 2006 through 2009.[1860]

Again, SCE mischaracterizes DRA's testimony. DRA is not saying that fires are unusual or infrequent. DRA is saying that fires are unpredictable, and whether and to what extent litigation will ensue after a fire is also unpredictable. The data SCE includes from the U.S. Forest Service bears this out. The data lists "Wildfires of 1000 Acres or Larger in SCE Service Territory: 2006 – 2009."[1861] The disparity between the years underscores the unpredictable nature of fires. Between 2006 and 2007, the number of wildfires dropped dramatically, dropped again between 2007 and 2008, and then rose between 2008 and 2009. There is simply no basis too assume, without more, that the costs of a fire in the base year will necessarily be replaced by similar costs going forward.

DRA recommends that the Commission exclude historic claims reserve amounts or settlement cost impacts associated with the Happy Camp fire because SCE has offered no specific proof why the costs associated with this fire should be considered a routine, recurring cost for forecasting purposes.

25.6. Tax Services

DRA recommends the removal of tax services costs from the record period. DRA's recommendation is based on the methodology used in calculating GRC related income tax

---

[1860] Ex. SCE-27, p. 33.

[1861] Ex. SCE-22, Appendix B, p. 6.

expense. The forecasted income tax expense is mostly comprised of operating revenues, operating expenses, deferred taxes, known tax rates, expected changed in income tax law, and Schedule M deductions. Many of these forecasted line items require no specialized assistance, are determined as part of input from various DRA analysts during the rate case, and/or can be handled by SCE's tax staff.[1862]

DRA asked SCE to explain why "millions in tax consulting work should be funded by ratepayers."[1863] DRA reviewed SCE's responses and agrees that some value exists, but sees no correlation between SCE's claimed benefits and actual benefits to ratepayers.[1864]

In Rebuttal, SCE argues the following:

> To cite just one example of how the use of such consultants directly affected this GRC, consider the recently enacted Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act). The Tax Relief Act provides for a 100% accelerated depreciation deduction for 2010 and 2011. The significance of this tax change and the Act's benefit to ratepayers has been acknowledged by the Commission. To comply with that legislation and *obtain the full benefit of the bonus depreciation provisions for ratepayers*, SCE worked closely with outside consultants. Those consultants were critical to the company's ability to quickly and accurately assess how the law would be applied and to assist in quantifying the impact of the law on SCE's operations and rates. Those efforts enabled us to submit an update to this 2012 GRC to reflect the Tax Relief Act and that significantly reduced SCE's revenue requirement.[1865]

SCE's claim that its work with its tax consultants obtains *for ratepayers* the "full benefit of the bonus depreciation provisions" is an open question. SCE certainly claims it has, but the Update phase of this proceeding, where "known changes due to governmental action such as changes in tax rates" is still to come. From DRA's review so far of SCE's Update to Reflect the Tax Relief Act, and DRA's review of SCE's modeling of the Tax Relief Act, DRA has serious questions about whether SCE's proposed methodology does in fact obtain for ratepayers the full benefits of the legislation.

[1862] Ex. DRA-22, p. 19.

[1863] Ex. DRA-22, p. 21

[1864] Ex. DRA-22, p. 22.

[1865] Ex. SCE-27, p. 39-40 (emphasis added).

In fact, it seems that SCE's Update methodology is modeled in such a way as to maximize benefits to its shareholders at ratepayer expense. If in fact, this is the sort of work that SCE's consultants perform, then this is additional reason to let shareholders fund it.

DRA continues to recommend the removal of tax related costs (FERC Account 923) not already removed for the period 2005 to 2009 as set forth in DRA's Confidential Audit report.[1866]

25.7. ACE Awards

DRA recommends removal of all ACE Awards for the period 2005-2009 from the various FERC Accounts that impact the GRC forecast. In order for DRA to remove the awards from both historic detail and forecasted detail, however, segregation by FERC Account is required as these awards are spread throughout SCE's business units. DRA requested this information be provided, and received the following from SCE:

> Per D.09-03-025, ACE awards were removed from SCE's authorized Test Year 2009 revenue requirement. For Test Year 2012, ACE awards are included in the 5 years of historical labor expense for each business unit. Each business unit prepares its own labor forecast by using unique forecast methodologies (*i.e.* averaging, trending, last year recorded, budget based). Since ACE awards are recorded in each business unit and each unit forecast is based on different forecast methodologies, the total request for ACE awards cannot be easily determined. The total dollar amount for ACE awards included in the historical period (2005-2009) is listed below:[1867]

As a follow-up response,[1868] SCE provided additional information identifying historic ACE Awards from 2005-2009 by FERC Account. DRA noted, this listing was all-inclusive containing ACE Awards recorded to FERC Accounts that are not part of the rate case.

DRA's recommendations for the ACE Awards in the Audit Report are guidelines for other DRA analysts to use according to their judgment. DRA's recommendations for ACE awards in the various business units are described in the sections of this brief relating to those business units.

[1866] Ex. DRA-22C, p. 19, Table.

[1867] DRA-SCE-AUDIT-LMW-14, Q.17b

[1868] Ex. DRA-22, p. 25, Response to DRA-SCE-AUDIT-LMW-20, Q.1.

25.8. Allowance for Funds Used During Construction

As part of its audit, DRA reviewed SCE's Utility Plant, including SCE's proposals for the Allowance for Funds Used During Construction (AFUDC) rate used to determine SCE's return on Construction Work In Progress. AFUDC represents the estimated cost of debt and equity funds used to finance utility plant construction. AFUDC is capitalized during plant construction. SCE recovers AFUDC in rates through depreciation expense over the useful life of the asset.

In SCE's last GRC, the Commission adopted an AFUDC rate of 7.7204% for 2007 through 2011.[1869] In the current GRC, SCE forecasts AFUDC rates of 8.1360% and 7.9578% for 2010 and 2011, respectively.

After reviewing SCE's proposal, DRA concludes that SCE's AFUDC estimates for 2010 through 2014 are based on unrealistically low forecasts of short-term debt that could be available for financing CWIP.[1870] DRA recommends that the Commission impute $1 billion, less Commission authorized "net exemptions"[1871] of short-term debt in the calculation of SCE's AFUDC rate.[1872]

DRA also disagrees with SCE's forecast of short-term debt rates as unrealistically high, and contradicted by an outside third party, Global Insight U.S. Economic Outlook. Taking these factors together, DRA recommends the Commission adopt AFUDC rates of 3.6694% for 2010, and 2.8291% for 2011 and 4.2936% for 2012.[1873]

25.8.1. Short-Term Debt Balances

The FERC formula for calculating AFUDC rates includes short-term debt balances.[1874] As SCE notes in its Rebuttal, FERC's rationale for including short-term debt balances in the AFUDC calculation is the following:

> Typically, short-term debt has not been included in rate of return computations for cost of service purposes on the grounds that such debt is temporary *and is used essentially for construction*

[1869] D.09-03-025, mimeo, p. 320.

[1870] Ex. DRA-22, p. 30, lines 5-7.

[1871] With Commission authorization, "net exemptions" include short- term debt used to finance balancing account under-collections and fuel inventory.

[1872] Ex. DRA-22, p. 30, lines 5-7.

[1873] Ex. DRA-22, p. 32, Table 22-9.

[1874] See Ex. SCE-27, p. 46, line7.

> *purposes;* however the cost of such debt represents a valid and necessary expenditure for conducting utility operations which ultimately must be recovered through rates. By adopting the approach of permitting the capitalization of short-term debt cost through AFUDC, we provide such a mechanism.[1875]

FERC's rationale shows that short-term debt is temporary and is used essentially for construction purposes. CWIP is typically financed with short-term debt. DRA's recommendation is consistent with FERC policies and methodology.

In June 2008, SCE submitted two applications to the Commission seeking permanent authority to borrow a total of $2 billion for short-term purposes. In Decision 08-10-015, the Commission granted SCE's request to have the authority to borrow up to $2 billion in short-term debt to finance its various short-term borrowing needs.[1876] The Commission decision did not impose any expiration date on the authority.

For January through May 2009, SCE had short-term debt balances as high as $1.893 billion, and averaging $1.596 billion for the five months. SCE did not obtain and had no short-term debt during June 2009 through December 2009 and, therefore, the short-term debt for 2009 averaged $664.9 million. During 2009, SCE demonstrated it was capable of obtaining short-term debt of at least $1.893 billion.[1877]

For January through July 2010, SCE had short-term debt balances as high as $446 million, and averaging $259.256 million for the seven-month period. For August through December 2010, SCE had no short-term debt at all.[1878]

DRA asked SCE why SCE had no short-term debt borrowing for the second half of the years 2009 and 2010. SCE explained that its cash flow was sufficient during those periods (June 2009-December 2009, and August 2010-December 2010) to enable SCE "...to meet its liquidity requirements without external short-term borrowing."[1879]

In its Rebuttal, SCE says, "DRA description of SCE's June 2008 Short-Term Financing Application is misleading, suggesting that SCE planned to borrow large quantities of short-term

---

[1875] Ex. SCE-27, p. 47, lines 3-9, emphasis added.

[1876] Commission Decision 08-10-015, dated October 2, 2008.

[1877] SCE response to DRA data request GCN-006, question 6.

[1878] SCE response to DRA data request GCN-006, question 7.

[1879] Ex. DRA-22, citing SCE Responses to DRA-SCE-AUDIT-GCN Q/A 1 and 2.

debt to finance construction."[1880] It is not clear what SCE is considers "misleading" about DRA's testimony or why.

DRA's testimony quotes directly from the Commission decision that granted the relief sought in SCE's Financing Application. According to that Decision:

> Edison requests an increase in its short-term borrowing authorization *primarily because of its large capital spending* program that is anticipated over the next several years. Edison states that it intends to invest approximately $19 billion over the next five years in replacing and improving aging infrastructure and other capital investments. Edison also states that it will need to issue debt and equity securities to partially fund the capital expenditures.[1881]

As DRA noted in its testimony, when SCE uses only cash flow to finance CWIP, except for opportunity cost, SCE has no direct cost for financing CWIP. Therefore, SCE's ratepayers should not be obliged to pay more than the short-term debt rate to CWIP financed by cash flow.[1882]

SCE should not benefit from its financing inefficiency and ratepayers should not be required to fund SCE's financing inefficiency. Long-term debt has a substantially higher interest rate than short-term debt. Whenever feasible, SCE should take the opportunity to finance CWIP with short-term debt and use cash flow from operations to pay down the other higher-cost forms of financing.

In Rebuttal, SCE says that:

> DRA's testimony shows a lack of understanding of the actual sources of the cash flow reinvested in new utility construction. These funds, which are also termed 'internally generated funds' stem from two main sources: (1) depreciation expense, which returns to investors the funds used to finance existing utility assets as these assets' values decline over time, and (2) utility earnings, the returns common shareholders received for the use of their money.[1883]

SCE obtained cash flows because of cancelled or delayed capital projects. Such cash flows used by SCE to finance CWIP do not cause SCE to incur debt and, therefore, no valid and

---

[1880] Ex. SCE-27, p. 48, lines 2-4.

[1881] D.08-10-015, mimeo, p. 4.

[1882] Ex. DRA-22, p. 29.

[1883] Ex. SCE-27, pp. 50-51.

necessary expenditure for interest occurs. DRA recommends that cash flow occurring because of cancelled or delayed capital projects should not earn more than the interest rate for short-term debt.

The actual sources of SCE's cash flow are SCE's ratepayers. Ratepayers pay depreciation expense. Depreciation is a non-cash expense that reduces the value of an asset. As noted above in the Policy, when SCE's actual capital expenditures fall short of forecasted capital expenditures, SCE's cash flows and profits increase at the expense of SCE ratepayers. DRA's position is that, in fairness to ratepayers, whenever SCE's CWIP is funded indirectly through canceling or delaying other forecasted capital projects, SCE's funding of CWIP should not earn more than the interest rate for short-term debt.

In cross examination of DRA's witness on the subject, SCE appeared to be suggesting that the $1 billion, less Commission-authorized net exemptions, DRA recommends be imputed for purposes of the Commission's calculation of AFUDC is not actually available to SCE because of certain additional "Cash Exemptions" SCE had referenced in a data request response.[1884] SCE asked DRA's witness:

> Q: So we could infer from that table that of the 1.688 labeled as general purpose borrowing in January 2009, 1.371 billion was held as cash, not to finance AFUDC, correct?
>
> A: That's what SCE stated.
>
> Q: And if you look across this table to other months of that year of 2009, you see the amounts of short-term debt and the other line items, they vary during the year, correct?
>
> A: Yes. The cash exemption to me is something that SCE decided to do. It's not a FERC exemption. And the formula for calculating AFUDC is based on the FERC requirement, not what SCE deems is exempt.[1885]

SCE's attempt to create "cash exemptions" where none are required serve only to enrich its shareholders at its ratepayers' expense. The Commission should give this argument no weight. The exhibit that SCE used to try to make this argument lists a "Cash Exemption" of $418 million.[1886] SCE seems to have created this "Cash Exemption" itself and provides no

---

[1884] Ex. SCE-64, p. 12; 21 RT 3600, Novack/ DRA.

[1885] 21 RT 3601-3602, Novack/ DRA.

[1886] Ex. SCE-64, p. 12.

authority for it from either this Commission or FERC. When that $418 million is replaced, the corrected amount shows an average of $617 million to finance CWIP in 2009.

In Rebuttal, SCE argues that DRA's recommendation to impute $1 billion, less Commission authorized "net exemptions" for purposes of the calculation of the AFUDC rate "would have negative consequences for credit quality."[1887] SCE offers no substantive evidence to support this argument. In 2009, SCE obtained short-term debt of $1.893 billion and there is no evidence that this level of short-term borrowing adversely affected SCE's financial metrics or credit ratings.

Finally, in Rebuttal, SCE argues that DRA should "not be allowed to use the AFUDC rate to reset the cost of capital."[1888] As should be clear from DRA's testimony, DRA is not attempting to do so. DRA's testimony notes that SCE's decision to use higher cost financing including common equity at a rate of 11.60% rather than lower cost short-term debt to fund CWIP results in higher costs to ratepayers than is necessary or equitable. If DRA has recommendations to make to SCE's cost of capital, it will do so in the Cost of Capital proceedings.

25.8.2. Short-Term Debt Rates

For the test year 2012, SCE forecasted a short-term debt rate of 4.40%, and a long-term debt rate of 6.06%.[1889] Both SCE's short-term and long-term debt rates are unrealistic: the former is contradicted by an outside source, the latter is contradicted in SCE's own Rebuttal. DRA recommends the Commission use the Global Insight U.S. Economic Outlook March 2011 forecasts for 3-month commercial paper. For the years 2010 through 2014, those rates are 0.23%, 0.34%, 1.76%, 3.83% and 4.02%.[1890] For the long-term debt rate, according to SCE's own Rebuttal, in May 2011, SCE issued 10-year fixed-rate first mortgage bonds with a coupon of 3.875%.[1891]

[1887] Ex. SCE-27, p. 51.

[1888] Ex. SCE-27, p. 53.

[1889] Ex. DRA-22, p. 29, lines 16-17.

[1890] Ex. DRA-22, p. 32, Table 22-8.

[1891] Ex. SCE-27, p. 44, footnote 76.

If SCE were not a public utility, surely its management would do more to bring down the AFUDC rate. Since SCE has made no effort to lower, or even contain, costs to its ratepayers, DRA recommends that the Commission do so.

DRA recommends that the Commission impute $1 billion as the amount of short-term debt used to calculate SCE's AFUDC rates for 2010 through 2014. This amount is reasonable, as it is 50% of the $2 billion short-term debt authorization SCE requested, and the Commission approved. In the AFUDC calculation for each year, the forecasted "net exemptions" would be subtracted from the $1 billion short-term debt amount imputed.

DRA recommends the Commission impute $1 billion, less Commission authorized "net exemptions" of short-term debt to that calculation and adopt AFUDC rates of 3.6694% for 2010, 2.2891% for 2011 and 4.2936% for 2012.

26. Conclusion

For all the foregoing reasons, and the reasons set forth in its testimony, DRA asks that its recommendations be adopted.

Respectfully submitted,

LAURA TUDISCO
NOEL OBIORA
NICHOLAS SHER
TRACI BONE

/s/ LAURA TUDISCO

Laura Tudisco
Staff Counsel

Attorney for the Division of Ratepayer Advocates

California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Email: ljt@cpuc.ca.gov
Phone: (415) 703-2164

September 26, 2011