Decision No. R12-0261

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

DOCKET NO. 11A-418E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2012 RENEWABLE ENERGY STANDARD COMPLIANCE PLAN.

RECOMMENDED DECISION OF
ADMINISTRATIVE LAW JUDGE
PAUL C. GOMEZ
APPROVING APPLICATION WITH MODIFICATIONS

Mailed Date: March 8, 2012

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I. STATEMENT

1. Public Service Company of Colorado (Public Service or Company) filed an application for approval of its 2012 Renewable Energy Standard Compliance Plan (Compliance Plan) on May 13, 2011. Along with its Application, Public Service filed the direct testimony and exhibits of Ms. Robin L. Kittel, Ms. Jannell Marks, Ms. Kari Chilcott Clark, Ms. Pamela J. Newell, Mr. Kurtis J. Haeger, and Mr. Scott B. Brockett. The three volumes of the Compliance Plan were attached as an exhibit to the direct testimony of Ms. Kittel. Despite the title of the Application, the Compliance Plan addresses both the 2012 and 2013 compliance years.

2. On May 16, 2011, the Commission issued Notice of the Application to all interested persons, firms, or corporations. The Notice advised that any person desiring to intervene in or participate as a party in this proceeding was required to file a petition for leave to intervene within 30 days after the date of the Notice, or no later than June 15, 2011.

3. At the Commissioners' Weekly Meeting on June 22, 2011, the Application was deemed complete and referred to an Administrative Law Judge (ALJ) for disposition.

4. Intervenors as of right in this proceeding included: Staff of the Colorado Public Utilities Commission (Staff); the Colorado Office of Consumer Counsel (OCC); and, the Colorado Governor's Energy Office (GEO).

5. Permissive intervenors in this proceeding included: Blanca Ranch Holdings, LLC and Trinchera Ranch Holdings, LLC, jointly (Trinchera Ranch); Climax Molybdenum Company and CF&I Steel, L.P. (jointly, Climax and CF&I); Interstate Renewable Energy Council (IREC); City of Boulder (Boulder); Colorado Renewable Energy Society; The Solar Alliance (SA); Colorado Solar Energy Industries Association (COSEIA); Western Resource Advocates (WRA); Colorado Independent Energy Association; Ratepayers United of Colorado, LLC (Ratepayers United); the Vote Solar Initiative (VSI); Mr. Sol Shapiro; and, Ms. Leslie Glustrom.

6. Based on a procedural schedule agreed to by the parties and adopted by Interim Order No. R11-0807-I issued July 26, 2001 and modified by Interim Order No. R11-1188-I issued November 4, 2011, an evidentiary hearing was scheduled for November 9 and 10, 2011. At the scheduled time and place, the hearing was conducted. All parties entered appearances at the evidentiary hearing with the exception of Mr. Shapiro and Ratepayers United.

7. Company witnesses Kittel, Marks, Chilcott Clark, Newell, and Brockett testified on behalf of Public Service at the evidentiary hearing, in addition to Mr. Steve Mudd, and

Mr. Kevin Schwain who filed rebuttal testimony on behalf of the Company. Mr. R. Thomas Beach testified on behalf of VSI and IREC. Mr. Benjamin Higgins testified on behalf of SA. Mr. Robert J. Harrington testified on behalf of COSEIA. Ms. Gwendolyn Farnsworth testified on behalf of WRA. Mr. Thomas F. Dixon testified on behalf of the OCC. Mr. William Dalton testified on behalf of Staff.

8. Exhibits 1 through 17, 19 through 24, 26 and 27, 30, 32 through 35, 44 through 46, and 48 through 54 were admitted into evidence. Exhibit 18 was not offered. Exhibits 25, 29, 36 through 38, and 41 through 43 were not marked. Exhibits 39, 40, 47, and 55 were not admitted. Confidential Exhibits were marked as 16C and 17C.

9. Post hearing statements of position were filed by Public Service, Staff, OCC, GEO, COSIEA, WRA, SA, IREC and VSI, Ms. Glustrom, Climax and CF&I, Trinchera Ranch, and Boulder.

10. On December 8, 2011, COSIEA filed a motion to accept its Statement of Position out of time. COSIEA stated that it attempted to file its pleading in a timely manner but was unable to due to a computer glitch. It was finally able to file its pleading shortly after 5:00 p.m. on the due date. COSIEA notes that all parties to this docket were served with its Statement of Position on the due date. No party opposed the motion.

11. Good cause is found to grant COSIEA's motion and accept its Statement of Position in this proceeding.

12. On December 28, 2011, WRA filed a Notice of Errata regarding its Statement of Position. WRA notes that the errors and corrections are not material and do not affect its position or the analysis contained within its Statement of Position. The first correction amounted to a change in a dollar amount found on page 8 of its Statement of Position

from $1.8 million to $1.4 million. The second correction was to delete a sentence contained in a footnote on page 8. WRA then filed a corrected Statement of Position which reflected the changes represented in its Notice of Errata.

II. DISCUSSION AND FINDINGS

13. Exhibits 1A, 1B, and 1C comprise the three volumes of Public Service's Compliance Plan. The plan depicts in detail how Public Service proposes to meet the requirements of the Renewable Energy Standard (RES) for 2012 and 2013. According to Public Service, its Compliance Plan relies on its existing owned eligible energy resources currently producing eligible energy, as well as contracted eligible energy resources expected to produce eligible energy during 2012 and beyond.

A. Renewable Energy Standard

14. The Colorado RES under which Public Service files this Application is codified at § 40-2-124, C.R.S. As a qualified retail utility (QRU) Public Service is required to meet a threshold percentage of retail sales from renewable energy given retail rate impact parameters. Since its enactment in 2005, the RES statute has been amended several times. Most significantly, these amendments raised the percentage of QRU retail sales from renewable energy and increased the retail rate impact limitation from 1 percent to 2 percent for investor-owned QRUs.

15. During the 2010 legislative session, the Colorado General Assembly passed House Bill (HB) 10-1001, which increased the RES for investor-owned QRUs such as Public Service to 30 percent by 2020, while maintaining the 2 percent retail rate impact cap. In addition, HB 10-1001 eliminated the solar specific requirement of the RES and replaced it with a higher Distributed Generation (DG) standard, such that an investor-owned QRU needs to

acquire DG equal to 3 percent of retail sales by 2020. The legislation additionally anticipated two types of DG – retail distributed generation (Retail DG) and wholesale distributed generation (Wholesale DG). Retail DG is defined as a renewable energy resource designed to provide electric energy to serve the customer's load located on the site of a customer's facilities and interconnected on the customer's side of the utility meter. Wholesale DG is defined as a renewable energy resource with a nameplate rating of 30 megawatts (MWs) or less that does not qualify as Retail DG. Additionally, at least one-half of the DG standard is required to be met with Retail DG.

16. HB 10-1001 requires Public Service to generate, or cause to be generated, electricity from eligible energy resources in the following minimum amounts:

- 12 percent of its retail electricity sales in Colorado for the years 2011 through 2014, with DG equaling at least 1 percent of its retail electricity sales in 2011 and 2012, and 1.25 percent of its retail electricity sales in 2013 and 2014;
- 20 percent of its retail electricity sales in Colorado for the years 2015 through 2019, with DG equaling at least 1.75 percent of its retail electricity sales in 2015 and 2016, and 2 percent of its retail electricity sales in 2017, 2018, and 2019; and
- 30 percent of its retail electricity sales in Colorado for the years 2020 and thereafter, with distributed generation equaling at least 3 percent of its retail electricity sales.

See, § 40-2-124(c)(I)(C) - (E), C.R.S.

17. Additionally, the 25 percent multiplier for eligible energy generated in Colorado was modified under HB 10-1001 at § 40-2-124(c)(III), C.R.S., to exempt Retail DG.[1]

[1] Public Service notes in Exhibit 1A, Vol. I of its Application that the 25 percent multiplier will continue to apply to Retail DG RECs contracted for prior to August 11, 2010. An additional multiplier, counting kilowatt-hours from Colorado Community-Based Projects as 1.5 kilowatt-hours of eligible energy, was added under HB 07-1281.

18. At the same time, the legislature also enacted HB 10-1342 which established community solar gardens, facilities designed to meet the solar needs of many customers. Customers can participate in these solar projects by acquiring shares of these larger facilities in exchange for a credit on their electric bills commensurate with the share of the solar garden generation that the customer acquired. An investor-owned QRU is obligated to acquire no more than 6 MWs of community solar garden capacity each year from 2011 through 2013.

B. Public Service's Compliance Plan

19. According to Public Service's Application, this Compliance Plan relies on the Company's existing owned eligible energy resources currently producing eligible energy, as well as contracted eligible energy resources expected to produce eligible energy during 2012 and beyond.

1. Non-Distributed Generation

20. Public Service is completing the acquisition of renewable resources selected in its most recent 2007 Electric Resource Plan (ERP). According to the Company, it has acquired approximately 500 MWs of additional wind resources and is in the process of acquiring an additional 200 MWs of wind under the 2011 Wind Request for Proposals (Wind RFP) under an amendment to the Company's ERP as approved by the Commission.

21. Public Service anticipated that the first 500 MWs of wind would be fully operational prior to October 1, 2011 and would generate approximately 1,723,900 megawatt hours (MWhs) annually. Public Service also predicted that the additional 200 MWs of wind would become operational before the end of 2012 and would generate approximately

800,000 MWhs annually. The Company indicates that energy purchased from those wind facilities[2] is eligible for the 1.25 percent in-state Renewable Energy Credit (REC) multiplier.

22. Public Service demonstrates compliance with the RES by retiring RECs in accordance with Rules 3654, 3655, and 3659 of the Commission RES Rules, 4 *Code of Colorado Regulations* 723-3-3650, *et seq*. The Company projects that it will have sufficient Non-DG RECs to meet the RES for the 2012 and 2013 compliance years. It also projects that it will have sufficient Non-DG RECs from existing eligible energy resources for compliance through at least 2021 under the current RES Rules. Consequently, Public Service seeks to exceed the minimum levels required under § 40-2-124, C.R.S., as amended by HB 10-1001 within the retail rate impact cap of 2 percent.

2. Wholesale Distributed Generation

23. Public Service intends to defer the acquisition of additional Wholesale DG resources to its ERP filing submitted on October 31, 2011 in Docket No. 11A-869E. The Company states that it has executed a solar energy purchase agreement with Greater Sandhill 1, LLC for a new 19.2 MW DC (16.1 MW AC) photovoltaic facility located in the San Luis Valley. The energy purchased from that facility is eligible for the 1.25 percent in-state REC multiplier. Additionally, the Cameo Solar Demonstration Project generated 550 RECs in 2010, which were included in Public Service's REC tracking database. Public Service also acquired the full output from two 30 MW solar facilities to be located in the San Luis Valley (San Luis Solar and Cogentrix) through power purchase agreements pursuant to its 2007 ERP.

24. As a consequence of acquiring the Greater Sandhill, San Luis Solar and Cogentrix projects, as well as the electricity from hydro and biomass projects that the Company acquired

[2] Cedar Point, Cedar Creek II and the remaining 200 MW of wind.

under previous RFPs, in addition to other generation owned or contractually acquired in prior periods, Public Service represents that it has, or will have sufficient Wholesale DG RECs to meet the RES for the 2012 and 2013 compliance years. Public Service projects it will have sufficient Wholesale DG RECs from existing eligible energy resources for compliance through at least 2021 under the current RES Rules.

3. Retail Distributed Generation – Solar*Rewards

25. Public Service proposes to continue the acquisition of Retail DG RECs from on-site solar facilities under its Solar*Rewards (SR) programs. Therefore, an integral part of the Compliance Plan is the Company's discussion of three acquisition scenarios (Minimum, Medium, and High Plans) for Retail DG capacity through its SR programs.

26. Regarding its "Small SR" and "Medium SR" programs, Public Service discusses the surge in applications it experienced in 2010 and the events leading to Docket No. 11A-135E where the Company sought an Order from the Commission to allow it to modify these programs in response to that surge and to lower the overall incentives paid to customers. The settlement agreement that emanated from Docket No. 11A-135E (11A-135E Settlement Agreement) set maximum levels for spending and capacity acquisitions under the Company's Small SR and Medium SR programs for a period extending through 2011 and until a final Order is issued in this proceeding. The 11A-135E Settlement Agreement also instituted an approach for reducing the standard offer incentives paid to customers over time in response to market conditions, where, after a threshold amount of on-site solar resources were acquired under an SR program (*e.g.*, Step 1 of 4 MW), the incentive amount would decrease (*e.g.*, from $0.16/REC to $0.15/REC).

27. Public Service explains that its "Large SR" program will continue to be offered through a competitive solicitation issued in 2012. The three programs are discussed in more detail below.

28. Public Service proposes to add to its Retail DG REC acquisition by launching a new program based on the community solar garden provisions in HB 10-1342 known as Solar*Rewards Community (SRC). SRC will enable customers who cannot or do not wish to participate in the SR programs the opportunity to participate in a solar generation program. Customers may purchase or lease shares of a community solar garden installed in their respective communities and will receive credits on their electric bill for the energy purchased at a central location. The SRC program alleviates the requirement to install solar facilities in the customer's home and provides additional solar program offerings.

29. For the RES compliance years 2011 through 2013, the SRC program will offer to purchase the energy and RECs from qualified community solar gardens up to 6 MWs each year. The offering will include up to 3 MWs to be acquired through standard offers for RECs from community solar gardens of 500 kWs or less. The additional 3 MWs will be acquired through a competitive solicitation for systems greater than 500 kWs up to 2 MWs.[3] Public Service indicates that it will not be able to initiate the SRC program in 2011 because this docket will not be resolved until 2012. As a result, it proposes to roll over the 6 MWs reserved for 2011 into 2012.

[3] Specific details of the SR programs are provided in Exhibit No. 1A, Vol. 1, Sec. 5, pp. 21-29.

a. Solar*Rewards Small Program

30. The Small SR program targets systems .5 kWs to 10 kWs in size and entails two subprograms—one for customer-owned on-site solar systems and the other for on-site solar system owned by third party developers.

31. Under the Compliance Plan, the Small SR customer-owned program will evolve into an entirely performance-based incentive (PBI) program at the heels of the 11A-135E Settlement Agreement. Under a PBI approach, the incentives paid to the customer are entirely based on the production of the on-site solar systems installed without the payment of upfront rebates. Therefore, under the customer-owned Small SR program, the end-use customer will enter into a contract with Public Service to generate solar energy for a period of 20 years with a PBI payment stream over 10 years based on actual production over that 10-year period.

32. The Small SR program for third party developers already operates similar to the SR Medium programs with only PBI payments and no upfront rebates. The third party developer will enter into a 20-year contract with Public Service for the sale of RECs and will be paid monthly based on actual production from the solar system over the 20 years.

33. A second meter dedicated to the generation will measure the production under both types of Small SR programs and will be owned, maintained, and read by Public Service and paid for by the system owner through a monthly metering charge based on the average embedded costs.

34. Public Service indicates that both of the Small SR program offerings will require reservation fees of $250 per project. The projects must be completed within 12 months, and the system size cannot vary more than 10 percent (more or less) from the estimated equipment size set forth in the initial application. Additionally, projects that take longer than 12 months to

complete will forfeit the originally guaranteed REC price and will be subject to the prevailing price at the time of completion. If a project takes longer than 12 months to complete or if its system size changes more than 10 percent, the deposit will be forfeited by the customer and credited to the deferred account of the Company's Renewable Energy Standard Adjustment (RESA) rate rider.

35. Public Service is targeting the capacity to be acquired under the Small SR program to approximately 38 percent of the total planned acquisitions of Retail DG under the Compliance Plan to comply with Rule 3655(f) which charges QRUs such as Public Service to allocate its expenditures according to the proportion of RESA revenues derived from residential and non-residential customer groups. Public Service calculates the portion of the RESA revenues obtained from residential and non-residential customer groups to be 38 and 62 percent respectively.

b. Solar*Rewards Medium Program

36. The Medium SR program for systems between 10 and 100 kWs has also evolved since Public Service's 2007 RES Compliance Plan. In response to legislation in 2009 that expanded the size of solar photovoltaic (PV) systems that could be acquired under a standard offer program, Public Service introduced a "Medium Tier 2" program for systems between 100 and 500 kWs.

37. Public Service represents that there has been greater interest in the Medium SR program in 2011 than any other year the program has been available. Public Service forecasts approximately 20 MWs to be completed by the end of 2011.

c. Solar*Rewards Large (RFP) Program

38. The Large SR program targets systems greater than 500 kWs to 2 MWs in size. Public Service notes that projects selected in the 2010 RFP are expected to come on-line in 2011. The Company expects approximately 2.6 MWs from that solicitation. Public Service proposes to continue the Large SR program by issuing an RFP in 2012 for up to 4 MWs.

39. The Large SR program currently has a project deposit fee of $5,000 which is collected when the project is accepted by the Company and refundable if the project is completed within the timeframe specified in the RFP. If the deposit is forfeited, the funds are deposited into the RESA.

C. Proposed Acquisition Targets for Retail DG

1. Minimum Plan

40. The Minimum Plan is designed to meet the minimum Retail DG compliance requirements of the RES by implementing a participation cap of 16 MWs per year, covering acquisitions from the Small SR, Medium SR, Large SR, and SRC programs.

41. Public Service states that it needs, on average, 16 MWs per year in order to meet the Retail DG compliance requirements over the planning horizon. The MW allocations for each individual program are designed to help keep the respective program allocations of RESA dollars in line with the relative proportion of each customer group's contributions to the RESA.[4] The Small SR and Large SR programs are each allocated 3 MWs annually for the next ten years, the Medium SR program is allocated 4 MWs annually, and the SRC program is allocated 6 MWs

[4] Public Service's underlying assumption is that Small Programs are residential, and Medium and Large Programs are non-residential customers, and the Solar*Rewards Community residential/non-residential split is assumed to be 50/50.

annually.[5] Public Service anticipates that the program allocation split utilizing theses acquisition levels are approximately 30 percent residential and 62 percent non-residential.

42. Using an approach for reducing incentive payments over time similar to the steps in the 11A-135 Settlement Agreement, the Company proposes to reduce the PBI by one cent rate per step for all programs. Public Service represents that it is proposing this one cent reduction rate per step to be consistent and fair.

43. The 2012 steps set forth in the Minimum Plan will not begin until the steps from the 11A-135E Settlement Agreement are completely filled. Once those steps are filled, the new steps would have a fixed price for the available program megawatts in each year due to the annual megawatt caps for each program under this plan.[6] According to the Company, the new 2012 pricing steps will start at $10/MWh less than the last steps in the Settlement.[7] The 2013 steps are not anticipated to begin until the steps from 2012 are completely filled. The step reductions in the PBI will reach a minimum level of $0.01/kWh at some point in the future and will continue at this level as an incentive for customers to continue participating in the program.

2. Medium Plan (Recommended Plan)

44. Public Service notes that while it wishes to meet its RES compliance requirements, another important goal is "to help sustain the Colorado solar industry while controlling spending." In order to achieve this goal, Public Service recommends that the Commission approve its proposed Medium Plan to acquire 36 MWs of Retail DG

[5] These acquisitions for 2012 to 2021 are set out in Hearing Exhibit No. 1A, Table No. 1, §5, p. 11, Vol. I of the Company's Application.

[6] As illustrated by Public Service in Hearing Exhibit No. 1A, Table No. 2, §5, Vol. I, under the Minimum Plan for the small customer owned program, after the Settlement steps are filled, there would be available a standard offer for 3 additional megawatts at a PBI of $0.13 per kWh.

[7] Public Service's Minimum Plan pricing and steps are illustrated in Hearing Exhibit No. 1A, Table No. 2, §5, Vol. I of the Company's Application.

each compliance year. This level of acquisitions exceeds the minimum Public Service needs to meet the Retail DG requirements of the RES. However, Public Service proposes limiting new contracts for on-site solar facilities to commitments, on a present value basis, that total no more than $46.7 million in 2012 and $37.9 million in 2013. Public Service contends that those spending limits would allow for MW target acquisitions by program as depicted in Table No. 3 of Volume I (Hearing Exhibit No. 1A), which total approximately 36 MWs per year, which includes an acquisition of 6 MWs annually of community solar garden capacity.

45. The pricing for the Recommended Plan is illustrated in Table No. 4 Section 5, page 13, of Vol. I (Hearing Exhibit No. 1A). According to Public Service, in order to meet the spending control component of its goal for the SR programs, the Company has developed two pricing steps per year as shown in Table No. 4. The price decline per step is $.01/kWh comparable to the Minimum Compliance Plan and the 11A-135E Settlement Agreement.

46. Pursuant to this approach, the Small SR and Medium SR programs will separately move to the second step as that current step capacity is filled by applications. Once the second step capacity is filled in that year, additional acquisitions will not continue until the start of the following year. Should the pricing steps per program not be filled in any year, the remaining MWs in that step will be carried forward to the next year.

47. For each SR program, Public Service intends to close the offering under that program once the steps for that year and all prior years have been filled. Nevertheless, Public Service intends to close the Small program in 2013 once all the megawatts in Step 4 are subscribed. In the Company's estimation, such a pricing structure reflects a market based approach to solar acquisitions.

48. Similar to the Minimum Plan, Public Service represents that it will honor the steps derived from the 11A-135E Settlement Agreement. In the event there are remaining unsubscribed steps for any SR program upon the Commission's approval of the Compliance Plan, those megawatts and step prices will be honored prior to using the steps and pricing set out in the Recommended Plan.

3. High Plan

49. The High Plan significantly exceeds the minimum RES compliance levels for Retail DG. This plan would add approximately 60 MWs of solar acquisitions each year. The High Plan would also acquire more retail DG than required to meet compliance with the Retail DG Standard.[8]

50. Public Service represents that it does not recommend adoption of this plan, but provides it in its Compliance Plan merely for informational purposes. The Company remarks that its position not to recommend adoption of this plan is because of concerns regarding structural problems in how retail rates interact with the requirements for net metering. The Company suggests delaying the adoption of a High Plan until its rates are re-designed to address these structural issues.

4. Intervenor Positions

51. Staff's and OCC's primary concern in this docket is the negative balance in the RESA deferred account which reaches approximately $69 million in 2013 and which requires ratepayers to pay interest at the Company's after tax weighted average cost of capital (currently at 7.74 percent). Accordingly, Staff and the OCC take the position that the Recommended Plan

[8] The High Plan megawatts and pricing steps are depicted in Hearing Exhibit No. 1A, Table Nos. 5 and 6, Vol. 1, Sec. 5, pp. 15 and 16.

is unnecessary since it allows Public Service to exceed the minimum RES requirements through 2021 at the expense of extending the negative RESA deferred balance into 2017.

52. Both Staff and the OCC argue that the acquisition of more Retail DG resources than is needed at this time precludes Public Service from acquiring potentially lower cost resources later on. For example, the OCC points to testimony in Docket No. 11A-135E, as well as to Hearing Exhibit 1A in this proceeding, in which Public Service cites a May 6, 2010 study by Deutsche Bank projecting that between 2010 and 2015, the installed cost of solar resources will drop by approximately 10 percent per year. The OCC concludes that deferring solar acquisitions to future years will thus result in lower costs which will benefit Public Service ratepayers.

53. While Staff acknowledges that § 40-2-124, C.R.S., establishes minimum RES requirements and that Public Service has been encouraged to exceed those minimums, it takes the position that the Minimum Plan allows Public Service to exceed the RES until at least 2020, which is ostensibly beyond the compliance requirements of this docket.[9] Public Service will also meet both the wholesale DG and non-Distributed Generation requirements of the RES through 2021 and beyond.[10]

54. While Staff does not take a position on whether Public Service should be permitted to carry over 6 MWs acquisition of solar energy for community solar gardens (CSG) from 2011 to 2012, it argues that Public Service should not be permitted to acquire more than 18 MWs of CSG through 2013.

[9] Hearing Exhibit No. 1B, Tables 4-2 through 4-4; Hearing Exhibit No. 16, Exhibit WJD-01 and WJD-02.
[10] Hearing Exhibit No. 1B, Tables 4-2 and 4-3, rows 75-88; Hearing Exhibit No. 16, Exhibit WJD-04.

55. The OCC calculates the interest charged to ratepayers as a result of the negative RESA balance at about $5.3 million per year, which it interprets as a portion of the RESA revenues being diverted away from the acquisition of additional renewable resources. While no analysis was conducted regarding the impact on the RESA deferred balance for the Minimum or High Plan, the OCC is confident that the Minimum Plan would eliminate the negative RESA balance earlier than under the Recommended Plan or the High Compliance Plan.

56. The OCC further argues that because of the millions of dollars credited to the RESA from margins earned from the sale of RECs, ratepayers are actually contributing more than 2 percent of their total bill to the RESA. Whether Public Service is in compliance with the retail rate cap or not, the OCC takes the position that it is not good public policy to acquire Retail DG beyond what is needed for RES compliance at this time.

57. The OCC thus takes the position that the Minimum Plan will allow the Company to achieve RES compliance beyond 2020, while protecting its customers from unneeded funding of Retail DG in the next two years during a down economic period. Should the Commission determine it is necessary to allow Public Service to acquire more than the minimum capacity needed for RES compliance, the OCC suggests that this can be accomplished at some future date.

58. Any environmental benefits which would be achieved by approving the Recommended Plan would be minimal since acquiring solar DG will not result in Public Service having to replace the lost solar DG with fossil-fueled resources, according to OCC. The OCC advocates that despite arguments in this proceeding regarding the economic benefits to the state of approving the Recommended Plan or High Plan, the Commission's duty is

not providing growth opportunities for the solar industry in Colorado; rather, its priority is to set just and reasonable rates.

59. The OCC also takes the position that Public Service should not be allowed to continue to fill the MW and dollar maximums established in the 11A-135E Settlement Agreement. The OCC recommends that the Commission deny Public Service's request that only after the unsubscribed remaining capacity under the terms and prices established in the 11A-135E Settlement Agreement are reached, will the Company begin to acquire the additional 36 MWs proposed in its Recommended Plan. The OCC asserts that the terms of the agreement are unambiguous that the rebate reductions and certain key parameters for certain SR programs are "to be implemented from January 1, 2011 to entry of a Commission order approving the Company's 2012 [RES] Compliance Plan …"[11]

60. In addition, the OCC states that the parties to the 11A-135E Settlement Agreement agreed that the structure of the SR program for 2012 and beyond was to be established in the 2012 RES Compliance Plan and future RES Compliance Plans. The Commission as well, counted on the limited duration of the terms of the agreement in approving it, albeit with reservations.[12]

61. CF&I and Climax also support the approval of the Minimum Plan instead of the Recommended Plan. CF&I and Climax support Staff's and OCC's positions that early, excessive acquisition of solar resources is imprudent since it is likely that solar may be more cost effective in the future. CF&I and Climax also support the position that the more solar Public Service

[11] *See*, Decision No. C11-0304, Docket No. 11A-135E issued March 21, 2011.

[12] *See*, Decision No. C11-0304, Docket No. 11A-135E, p. 9, ¶ 23.

acquires, the higher the negative RESA deferred balance, which results in unnecessary higher costs for the Company's ratepayers.

62. In contract, the GEO supports the Company's Recommended Plan for the acquisition of Retail DG, arguing that it supports the goal of fostering economic development within Colorado and a culture of environmental stewardship. While the GEO acknowledges Staff's and OCC's concerns regarding the negative deferred RESA balance, it nonetheless argues that the Recommended Plan has broad, long-term benefits that outweigh the near-term costs.

63. WRA, on the other hand, supports approval of Public Service's High Plan which targets the acquisition of 54 MWs of customer-sited DG resources per year in 2012 and 2013. WRA takes the position that this plan provides superior environmental benefits for all ratepayers in the form of reducing the use of fossil fuels and the accompanying reductions in SO_2, NO_x, mercury, and greenhouse gas emissions. WRA notes that all ratepayers, including customers that do not directly participate in the SR programs, enjoy those environmental benefits. In addition, WRA points to additional benefits of the High Plan in the form of federal tax credits and low PV module prices that are currently available.

64. WRA observes that Public Service received applications in 2011 at a faster rate than in 2010, and in fact, the medium-sized systems sold out in a few months' time.[13] Additionally, as of August 2011, SR participants had installed approximately 26 MWs of customer-sited PV.[14] At the same time, approximately 27 MWs of outstanding applications for

[13] Transcript Vol. 1, Kittel testimony, p. 124, lines 5-7, and Transcript Vol. 1, Newell testimony, p. 172, lines 3-8.

[14] Hearing Exhibit No. 8, Rebuttal Testimony of Pamela J. Newell, Table 1, p. 11.

projects are in the queue waiting to be completed.[15] In reviewing the actual installed capacity with the existing pipeline of projects, WRA finds adoption of the High Plan imperative

65. Adoption of the High Plan will not be a significant influence on the RESA deferred balance according to WRA, because of the conversion from up-front payments to lower, performance-based payments for the SR program in 2011 as a result of the 11A-135E Settlement Agreement.

66. SA advocates for higher acquisition levels for Retail DG than proposed in the Recommended Plan as well. The SA plan proposes the acquisition of 86 MWs over the two-year compliance period, inclusive of SRC, which it points out is 14 MWs more than Public Service's recommended 72 MW acquisition level but much less than the High Plan's 120 MW acquisition level.

67. SA also opposes Public Service's proposal to combine the Medium Tier 1 and Medium Tier 2 portions of the SR program. SA argues that the RFP program is unlikely to continue to draw numerous bids due to its small size. The number of MWs available under this program is insufficient to make it cost-effective for companies to invest time and resources into developing bids, as SA sees it.

68. Regarding the SRC program, SA, along with IREC and VSI, are of the opinion that the proposed SRC incentives are too low and will result in under-investment in the program. These parties also consider the calculation of the credit provided to SRC customers inappropriate because it undervalues solar gardens generation and sets the SRC rate lower than a level that reflects reasonable valuation of the power producing a solar garden installation.

[15] Transcript Vol. 1, Newell cross-examination, p. 182, lines 6-1 and p. 183, lines 1-9.

69. COSEIA supports the alternative Recommended Plan as proposed by SA as the most cost effective way to help drive down energy costs, promote job creation, and achieve compliance with the RES.

5. Findings and Conclusions

70. The complex process of assessing the various and intricate facets of a QRU's RES Compliance Plan has been oft discussed and well documented. The assessment of those facets involves a determination of legislative intent regarding the RES, the interaction of the RES statutes and rules, the findings of previous Commission proceedings, and the testimony and evidence presented by the various parties in this proceeding.

71. The RES has been amended significantly over the last several years and the Commission has endeavored to promulgate rules to keep pace with those changes. In reaching a decision on whether this Compliance Plan merits approval, in whatever form, the Commission must be mindful of the legislative intent behind the RES and its various amendments, while also taking into consideration its statutory and constitutional obligations. The attempt to balance these diverse interests can never be a precise exercise because, in order to reach some semblance of symmetry, it becomes impossible to fully assuage each and every divergent concern and interest. Nonetheless, the end result should attempt to be a fair and equitable decision that results in a Compliance Plan that benefits Colorado overall, with minimal cost impact on ratepayers, while staying as true as possible to the intent of the RES. It is upon this philosophy that this Recommended Decision is based.

72. While Public Service does not intend to acquire Non-DG resources or Wholesale DG resources pursuant to the Commission's approval of this Compliance Plan, it does propose to acquire 36 MWs of Retail DG RECs from on-site solar facilities through its Small SR,

Medium SR, and Large SR programs in each of the two compliance years 2012 and 2013. In addition, it proposes to roll over the 6 MWs of community solar garden capacity reserved for 2011 into 2012 for its SRC program and to continue to acquire any unsubscribed capacity remaining under the terms of the 11A-135E Settlement Agreement at the established prices before acquiring the additional 36 MWs in each year under the Compliance Plan.

73. Staff and the OCC are correct that while the RES compliance levels provided in § 40-2-124(1)(c)(I), C.R.S., are minimum compliance levels, nothing in the statute requires a QRU such as Public Service to acquire more than the minimum levels. Certainly, approving Public Service's Minimum Plan achieves the short term requisite levels of DG required under the statute. However, as pointed out by the Company and several other intervenors including WRA, SA, VSI, and COSIEA, approval of the Minimum Plan may have long-term consequences to the Colorado solar industry which may result in unanticipated long-term costs.

74. In determining the level of on-site solar acquisition to approve in the Compliance Plan, it is critical to consider the short-term, as well as the long-term consequences of what is approved. Undoubtedly, the Minimum Plan will help keep costs in check and result in a lower RESA deferred balance, which will be reduced more quickly than the other two plans. However, whether the Minimum Plan will help sustain a viable and robust solar industry into the future is debatable. A robust market that remains viable in the long-term is crucial to keeping the costs of Retail DG and the cost of compliance with the DG requirements of the RES reasonable. Basic economic theory tells us this. Although the Minimum Plan appears cheaper now, the possibility of long-term cost increases is of concern.

75. The OCC points out that a 2010 study by Deutsche Bank projects the installed cost of solar will drop by approximately 10 percent per year. But as with any such study,

such findings are speculative and many intervening events can alter those projections. Additionally, even if solar costs drop by a certain percentage each year between 2010 and 2015, such savings would most likely be offset by an anemic market because of low demand as a result of approving the Minimum Plan.

76. On the other hand, approval of acquisition of 74 MWs in each of the two compliance years as recommended by SA, or the 60 MWs of the High Plan as supported by WRA also have objectionable consequences. Those proposals will increase the RESA deferred balance to even higher negative levels and extend the time the balance is negative at least an additional year.[16] The costs associated with these plans are simply too high for the resulting benefits.

77. The Medium Plan as proposed by Public Service appears to present that most palatable plan. While the Company will exceed the minimum amount of Retail DG that it must acquire to meet the RES for 2012 and 2013, the proposed 36 MWs will help sustain the Colorado solar industry at a reasonable cost to ratepayers. The decision to approve the Recommended Plan is bolstered by Public Service's commitment to limit new contracts for on-site solar facilities to commitments on a dollar basis in 2012 and 2013. The costs of the Recommended Plan are further mitigated by the utilization of the PBI framework rather than the up-front incentives. The use of PBIs should also help curtail the negative RESA deferred balance and ensure the balance approaches zero or moves to a positive balance in a timely fashion. For these reasons, it is found that the acquisition levels for Retail DG as set forth in the Medium Plan should be approved as proposed by Public Service.

[16] Hearing Transcript, Vol. 2, p 91, lines 7-23.

78. SA recommended the implementation of certain milestones that would permit a project to be removed from the queue prior to the expiration of 12 months. In addition, COSEIA suggested that certain projects be allowed to exceed 12 months for completion. It is found that implementation of these recommendations is not necessary at this time and will not be implemented.

79. As part of its Compliance Plan, Public Service proposes that the 2012 steps will not begin until the megawatts in the steps from the 11A-135E Settlement Agreement are completely filled. However, the OCC points out the terms of the agreement provide as follows:

> **14. Duration of Agreement –** The Agreement establishes Rebate reductions and other key parameters for certain Solar*Rewards programs to be implemented from January 1, 2011 *to entry of a Commission order approving the Company's 2012 Renewable Energy Standard ("RES") Compliance Plan ("Settlement Period").* The Settling Parties agree that the structure of the Solar Rewards program for 2012 and beyond will be developed in the Company's 2012 RES Compliance Plan and future RES Compliance plans.
>
> (Emphasis supplied)

Further, the Commission stated in Decision No. C11-0304 at ¶34 that the "[s]ettlement is meant only to serve as a 'bridge' through the period when Public Service develops and the Commission considers the Company's 2012 RES Compliance Plan." It is evident that the settling parties and the Commission contemplated that the terms and activities agreed to under the 11A-135E Settlement Agreement were to be of limited duration. A firm deadline was established in ¶14 of the Settlement Agreement. Nothing in the terms of the Settlement Agreement contemplated that Public Service could continue to acquire any unsubscribed capacity remaining under the terms and prices established there.

80. It is found that the OCC is correct in its assessment that the 11A-135E Settlement Agreement was never intended to extend beyond the issuance of a final Commission decision in

this proceeding. In addition, there was no evidence presented that the settling parties agreed to waive that provision or to amend the Settlement Agreement. Therefore, it is found that any further solar acquisitions under the terms of the 11A-135E Settlement Agreement must be terminated and Public Service must immediately begin solar acquisitions pursuant to the 2012 steps outlined in the Compliance Plan.

81. Public Service established the MW acquisition targets for the Small SR and Medium SR programs in conjunction with its proposed steps and declining incentive levels. These steps and incentives also form the basis of the Company's estimates for the funds it expects to advance to the RESA in 2012 and 2013. These issues are addressed further below.

D. Solar*Rewards Incentive Levels

82. As explained above, Public Service proposes decreasing standard offer PBIs for its Small SR and Medium SR programs based on specific steps of acquired capacity that combine to the overall acquisitions totals set forth in the Minimum, Medium, and High Plans. This approach is modeled after the steps and declining incentives adopted in the 11A-135E Settlement Agreement.

83. Public Service also proposes a standard offer PBI for the SRC. The standard offer pricing for the SCR is explained in Section 5, pages 22-24, of Vol. I (Hearing Exhibit No. 1A).

84. Staff argues that the Company may be ignoring the price signals it receives through the RFPs issued for the Large SR program when determining the standard offer incentive levels for the other SR programs. According to Staff, since the time when REC prices were first established in Docket No. 06A-478E, annual responses to Large SR program RFPs have indicated the market is willing to accept declining prices for RECs. Staff recommends that

the Commission consider such information (contained in Highly Confidential Exhibit Nos. 16C and 17C) to establish more market-based incentive levels for all of the Company's SR programs.

85. SA, on the other hand, argues that the 11A-135E Settlement Agreement has achieved Public Service's goal of reducing the pace of SR spending; therefore incentive level reductions should now flatten out to avoid restrictions on supply that could be costly. SA notes that the percent decreases in incentives proposed by the Company from the end of the 11A-135E Settlement Agreement through 2012 are 17 percent for Small SR customer owned solar and 22 percent for Small SR third party and Medium SR customers.

86. SA maintains that its proposed incentive levels (as outlined in Table 3 of its Statement of Position) would result in a Compliance Plan that is more in line with the stated goals of the SR program, as it would allow the program to more accurately match declines in the costs of solar equipment with incentive reductions. The proposed incentive levels, according to SA, adhere to Public Service's stated goals of providing support for customers to participate in the SR program, and of sustaining solar installation levels of at least 30 MWs per year, while steadily decreasing overall funding and funding for each MW acquired.[17] SA proposes these adjustments because it is concerned that the pace of incentive declination is currently too aggressive and will serve to temper robust competition in the Colorado solar marketplace.

87. Boulder's chief focus is on the SRC. It points to § 40-2-127(5)(a)(II), C.R.S., which provides that for community solar gardens of 500 kWs or less, QRUs must make standard offers at prices comparable to the prices offered by the QRU under standard offers issued for other types of on-site solar generation. Since the solar gardens program is new and untested,

[17] Hearing Exhibit No. 1, Direct Testimony of Robin Kittel, pp. 28-29; Hearing Exhibit 1A, Vo. 1, Sec. 5, pp. 8 and 12.

Boulder advocates for the appropriate incentive level in light of three principles. First, the incentive should encourage participation in community solar gardens. In determining the appropriate incentive levels, Boulder urges the Commission to keep in mind the legislative purpose for introducing community solar gardens, which is to encourage "broad participation" in solar electric generation. Second, until experience is established with SRC and ratepayers' response to it, the program should be given additional attention in the form of higher incentives. Once a level of experience is established, incentives can be adjusted accordingly. Finally, the Commission should acknowledge that community solar gardens are intended to broaden the public's participation in distributed solar electric generation and not detract from rooftop solar.

88. In finding a balance of proper incentive levels, it is noted that the incentives proposed by Public Service fall somewhere midway between the undefined, lower incentives proposed by Staff and the specific, higher incentive levels proposed by SA and other solar industry intervenors. Public Service acknowledges that the results of RFPs should be an element that is considered when determining incentive levels; however, it notes that lower RFP prices are likely a function of economies of scale of larger projects rather than a reflection of the market.

89. Regarding the SA proposed incentive levels, Public Service argues that those incentives are not supported by any company or industry specific information on the cost structure and financing terms prevalent in the industry. Public Service contends that SA overestimated the amount of incentives needed from the Company by underestimating the amount a subscriber may be willing to pay the subscriber organization for the generation from the solar garden.

90. As pointed out by Public Service, the incentive levels it proposes are basically a continuation of the levels established in Docket No. 11A-135E. The incentives proposed in the

Medium Plan thus move downward from the relatively higher levels set forth in the 11A-135E Settlement Agreement. While several parties have complained that the terms of the 11A-135E Settlement Agreement were hastily arrived at and not based on competent evidence, it is found that there was not sufficient evidence in this proceeding to show that the proposed incentive levels are inadequate, improper, or harmful to the market. It is further found that the incentives proposed by the Company will allow developers sufficient room to earn a reasonable profit and offer installation discounts in order to keep the market robust.

91. As discussed above, Public Service has proposed to offer the incentives still available under the terms of the 11A-135E Settlement Agreement before reducing the incentives further pursuant to the steps outlined for the Recommended Plan. However, solar acquisitions under the terms of the 11A-135E Settlement Agreement will be terminated once a final Commission decision issues in this Docket.

92. Section 40-2-124(1)(g)(III), C.R.S., establishes that an investor-owned QRU such as Public Service has the discretion to determine, in a nondiscriminatory manner, the price it will pay for RECs through its SR programs provided that the on-site solar systems are no longer than 500 kilowatts. Nevertheless, Public Service requests that when approving the Company’s overall plan, the Commission approve the declining incentives set forth in its Recommended Plan.

93. Adjustments to the PBI values proposed by Public Service as part of its Recommended Plan (as illustrated in Hearing Exhibit No. 1A, Vol. 1, Table No. 4, Section 5, page 13) are likely necessary to provide reasonable continuity in the declining incentive levels and to prevent a steep decline in the incentives offered to customers eligible to participate in the Small SR program. In contrast, no changes are likely required for the Medium SR program.

94. The declining incentives set forth in the following table are therefore approved for implementation consistent with the acquisition targets in the Company's Recommended Plan for 2012 and 2013. The starting incentives for the Small SR programs are intended to compensate for the elimination of any upfront payments to customers in favor of an entirely performance-based compensation regime. The modified PBI levels fall during 2012 and 2013 to match the Company's proposed levels in 2014 and are then reduced by $0.01/kWh per step until the PBI equals $0.01/kWh in accordance with the Company's proposal. The PBI incentives levels adopted for the Medium SR program are identical to the incentives proposed by Public Service for its Recommended Plan.

Table 1. Performance Based Incentives for 2012-2013

		Small SR Customer Owned	Small Third-Party Developer	Medium SR
		(/kWh)	(/kWh)	(/kWh)
2012	Step 1	$0.15	$0.12	$0.10
	Step 2	$0.14	$0.11	$0.09
2013	Step 3	$0.13	$0.09	$0.08
	Step 4	$0.11	$0.07	$0.07
2014	Step 5	$0.09	$0.06	$0.06
	Step 6	$0.08	$0.05	$0.05
2015	Step 7	$0.07	$0.04	$0.04
	Step 8	$0.06	$0.03	$0.03
2016	Step 9	$0.05	$0.02	$0.02
	Step 10	$0.04	$0.01	$0.01
2017	Step 11	$0.03	$0.01	$0.01
	Step 12	$0.02	$0.01	$0.01
2018-2021	Step 13	$0.01	$0.01	$0.01

E. Participation of Low Income Customers in Community Solar Gardens

95. The participation of low income customers in Public Service's proposed SRC program is directed by Rule 3665(d)(V)(b), which provides that "[a]cquisition of energy and RECs from eligible low-income CSG subscribers to CSGs may be either through dedicated low-income CSGs or low-income set asides within other CSGs."[18]

96. Public Service states that Rule 3665(d)(V)(b) allows a QRU to choose the manner in which it complies with the rule by setting aside capacity for low income subscribers by accepting applications from solar gardens comprised exclusively of low income subscribers, or, it may set aside capacity for low-income subscribers by ensuring that each solar garden has some low-income subscribers. Public Service chose the latter option.

97. IREC argues that the Company's approach is deficient and the Commission should instead adopt an approach that recognizes the unique circumstances and needs of low-income ratepayers. IREC maintains that Public Service's proposal does not account for low-income ratepayers' unique circumstances and lacks the level of transparency necessary to allow developers of community solar gardens to plan effectively for the inclusion of low-income ratepayers. IREC laments the fact that Public Service has only provided limited information and that it will provide additional information on its website in the future. IREC proposes providing additional incentives directly to individual low-income solar garden subscribers and/or locate the offering of low-income community solar garden subscriptions within the general weatherization and energy efficiency programs run by an entity such as Energy Outreach Colorado.

[18] The Commission's RES Rules concerning community solar gardens were promulgated in Docket No. 10R-674E and took effect January 14, 2012.

98. By requiring all proposed community solar gardens in the SRC program to have a 5 percent set aside for low-income subscribers, Public Service has complied with Rule 3665(d)(V)(b) by proposing one of the two options available for setting aside capacity for low-income subscribers. The issue of involving low-income customers in energy saving and renewable energy programs has vexed the Commission for quite some time. However, inclusion of low-income customers is, in the opinion of the undersigned ALJ, of paramount importance. Therefore, while it is found that Public Service has met the general requirements of Rule 3665(d)(V)(b), the ALJ strongly encourages the Company to continue to develop low-income programs with more depth and substance. The Company is further encouraged to work with entities such as IREC and Energy Outreach Colorado to develop unique and sustainable programs to involve low-income participants in these programs as much as possible.

F. Windsource Program

99. Public Service expects annual sales growth rates of Windsource of 1 percent from 2011 through 2013, based on historic growth rates, industry trends, and its marketing plans. The Company foresees growing sales among commercial and industrial customers as the primary driver behind the growth of the program, particularly among public entities and customers using Windsource to obtain Leadership in Energy and Environmental Design certification points. Residential penetration rates are projected to remain flat due to economic conditions. Revenue collected through Windsource toward the RESA is forecast at $4,688,467 in 2012 and $4,735,351 in 2013.

100. Public Service proposes to keep the 2012 Windsource premium the same as the 2010 premium of $2.1588 per 100 kWhs. The Company recalculated the Windsource rate using current assumptions and is within 20 percent of the 2010 rate cited above. As a result,

Public Service proposes no adjustment to the Windsource rate in this proceeding, in accord with Commission Decision Nos. C10-1033 Docket No. 09A-772E issued September 23, 2010, and C10-1221 Docket No. 09A-772E issued November 10, 2010.

101. The calculation of the Windsource premium is described in Volume 1 of the Compliance Plan, as well as in the direct testimony of Mr. Haeger. The calculation of the Windsource premium is based on the concept that the premium is equal to the average incremental cost of adding renewable energy to Public Service's system to replace the RECs that are being used in the Windsource program. The average incremental cost of adding renewable energy to Public Service's system is calculated in a manner similar to the method in which the Company determines the retail rate impact for the RESA. Ultimately, the Windsource premiums are credited to the RESA account to allow for the acquisition of more renewable energy.

102. Staff proposes that the calculation of the Windsource premium should be changed to a more transparent pricing mechanism. However, it believes that it is more appropriate to address the pricing of the premium in Docket No. 11A-833E, which is a pending application by Public Service for approval of revisions to its Windsource program.

103. Ms. Glustrom contends that the evidence of record in this proceeding shows that the price Public Service is charging for Windsource does not reflect the true price of providing the Windsource product. It is Ms. Glustrom's position that Windsource customers have likely been overcharged for many years now. Ms. Glustrom cites Table 4-3 of Hearing Exhibit No. 1B which illustrates the RECs accumulated by Public Service under the 2 percent retail rate impact limit of the RES. Ms. Glustrom posits that Windsource RECs could easily be retired from this pool for approximately a 2 percent rate impact or less due to the predominance of wind in the

Windsource product. She sees no need for the approximately 20 percent rate impact that accompanies the current Windsource premium.

104. Ms. Glustrom also argues that Public Service has sufficient information from the recently approved purchased power agreement with the Limon II wind farm to allow it to update the Windsource premium calculation. She maintains that information on the Limon II wind farm in Docket Nos. 11A-833E and 11A-689E clearly shows a difference between the wind price assumed in this Docket and the price assumed in those two Dockets, indicating that a reformulated price for Windsource could be much lower than proposed by the Company here.

105. Ms. Glustrom states that if Public Service intends to base the Windsource premium on new wind acquisitions, then it should be required to recalculate the Windsource premium now using the price of wind from the Limon II wind farm. Should the premium deviate substantially from the 2 percent rate impact, Ms. Glustrom urges that the Company should be required to explain the reason for the difference, as well as clearly identify and document all assumptions utilized in its determination.

106. It appears that Public Service has fully explained the methodology for calculating the Windsource premium here and in its compliance filing to Decision No. C11-0359 in Docket No. 09A-772E issued April 5, 2011. It is not disputed here that the calculation is complex; nonetheless, the Company has provided details as to how the premium is derived.

107. The Windsource premium and the methodology for calculating it will not be changed here; therefore the Windsource rate will remain at $21.58/MWh. As to whether the price Public Service is charging for Windsource fails to reflect the true price of providing the Windsource product, and as a result, customers are overcharged, it is noted that these issues and other issues raised by Ms. Glustrom, while not invalid, are better addressed in

Docket No. 11A-833E. While the methodology for calculating the premium and how RECs from the Windsource program are retired for compliance with the RES and for Windsource are derived from Docket No. 08A-260E, it bears reiterating that these issues are better addressed in Docket No. 11A-833E, which is dedicated solely to the Windsource premium.

G. Retail Rate Impact and Cost Recovery Mechanism

1. Retail Rate Impact

108. The retail rate impact constraints of implementing the RES are established in Rule 3661. The net retail rate impact of a QRU's compliance with the RES is not to exceed 2 percent of the total electric bill annually for each retail customer as provided under § 40-2-124(1)(g)(I), C.R.S. The retail rate impact is to be determined net of new alternative sources of electricity supplies reasonably available at the time of the determination.

109. The methodology for calculating the retail rate impact is set forth in Rule 3661(h), which details how a QRU determines the difference in costs between two alternative scenarios of electric resources over the RES planning period. The RES plan scenario consists of the new eligible energy that is added during the RES planning period. The No RES plan scenario consists of those non-renewable resources reasonably available and necessary to replace the new eligible energy resources in the RES plan to meet the QRU's capacity and energy requirements. The costs of the No RES plan thus quantifies the system avoided costs, and the difference between these avoided costs and the RES plan costs results in the calculation of the incremental cost funded by the RESA.[19]

[19] Public Service defines avoided costs as the costs that would have been experienced without the addition of any eligible renewable resources and refers to them as "ECA costs."

110. For eligible energy resources whose incremental costs have been locked down in a previous compliance plan or other proceeding, the locked down resources are included in both the RES and no RES plan, but the locked down incremental costs of those resources are separately added back when determining the cost funded by the RESA.

111. When developing the RES and No RES plan scenarios, Public Service used the same methodologies and assumptions it used in its most recently approved ERP in Docket No. 07A-447E, as required by Rule 3661(e). However, it did not use the same carbon cost assumptions. While it was assumed in Docket No. 07A-447E that carbon regulation would be enacted in 2010, no such legislation was enacted and it does not appear that such legislation is on the horizon prior to 2014. As a result, Public Service did not include any carbon cost imputations in the model runs and other calculations as depicted in Table 7-3 of Volume 2 of its Plan.

112. While Public Service did not include any carbon cost imputations in the model runs, it did include a sensitivity case that assumes the same carbon imputation costs of $20 per ton escalating at 7 percent annually as approved in Docket No. 07A-447E, but on a delayed implementation schedule of 2014.

113. Based on the RES and No RES model rules and projected RESA collections from ratepayers, Public Service estimates that it can eliminate the negative RESA balance in 2017. Including the carbon cost imputations beginning in 2014, the Company estimates that the RESA balance becomes over recovered in 2017. However, Public Service acknowledges that its estimate is “highly dependent” on the market conditions used to determine the incremental costs of the renewable resources.

2. Cost Recovery Mechanism

114. By the Company's estimation, the current and projected negative RESA balance is primarily the result of the increasing costs and participation in the SR programs and greater incremental costs associated with wind energy volume that was added as a result of the 2009 All-Source solicitation. The chief cause for the negative RESA balance through 2011, according to the Company, is the up-front incentives offered in the SR program. However, with the switch to PBI contracts, Public Service anticipates that SR program costs will not be a significant issue for the RESA account in 2012 and beyond.

115. Public Service explains that it plans to use the same cost recovery and deferred accounting mechanisms for its Compliance Plan that the Commission approved for the Company's 2010 Compliance Plan. Those mechanisms include: (1) using the electric cost adjustment (ECA) to recover the costs of eligible energy that match the costs of the avoided non-renewable resources; and, (2) using the RESA to recover the costs of the eligible energy that are incremental to the costs of the avoided non-renewable resources and the program and administration costs. Public Service maintains that continuing to recover the incremental costs through the RESA provides a ready check on whether it has complied with the 2 percent retail rate impact limit pursuant to Rule 3661(a).

116. The Company discusses how it used the ECA deferred account as the true-up mechanism in the 2009 and 2010 Compliance Plans. The costs associated with the renewable energy facilities were initially charged in full against the ECA, then Public Service determined through modeling, the incremental costs of those resources, derived from the difference between the RES plan and the No RES plan, and transferred funds from the RESA deferred account to the

ECA deferred account to reimburse the ECA for those incremental costs based on actual production. According to Public Service, this method allows the RESA to continue to provide for the incremental cost of eligible energy.

117. Public Service points out that the exceptions to this accounting treatment are the rebates and REC payments made to SR customers. Those payments are initially charged against the RESA deferred account. Then the modeled avoided ECA costs related to the SR DG are transferred from the ECA deferred account to the RESA deferred account. Public Service asserts that this results in the RESA paying only the incremental costs of the SR program.

118. Additionally, the RESA is to be used to pay for the purchased REC costs and program and administrative costs of SR and SRC. Program costs include costs for RECs, rebates REC certification, meter sets for second meter, and incremental energy costs. Administrative costs include incremental labor and employee expenses, marketing, software for the REC database, software for SRC, billing costs, and audit fees. Wholesale revenues received for the eligible energy assumed in the Compliance Plan are to be credited against the RESA deferred balance. In addition, the premiums paid by Windsource customers and REC margins that the Commission determines should be credited against the RESA deferred account will be credited against the deferred RESA balance.

119. Public Service notes that as of the end of April 2011, the deferred RESA balance is a negative $69 million. In addition, Public Service projects an additional $55.5 million added to the deferred RESA balance as a result of a request for permission for Public Service to transfer certain REC trading customer share margins to the deferred account.

3. Lockdown of Incremental Costs

120. Public Service indicates that pursuant to Rule 3661(h)(V), it calculated the locked down incremental costs of Cedar Creek Wind II, Cedar Point Wind, the 2011 Wind RFP 200 MW Wind, and San Luis Solar PV. The Company explains that it used the same assumptions and methodologies used to calculate the incremental costs of eligible energy resources.

4. Intervenor Positions

121. CF&I and Climax argue that the Commission should either deny Public Service's application or require an amendment to the application, because the proposed Compliance Plan violates the 2 percent retail rate impact cap as set out in § 40-2-124, C.R.S. However, CF&I and Climax put the blame on Commission rules by arguing that Commission Rule 3661(h)(III) unintentionally allows a utility to exceed the 2 percent retail rate impact limit.

122. By CF&I and Climax's reasoning, the dilemma with Rule 3661(h) is that the entire cost of specific resources, including those acquired prior to July 2006 and those eligible as Section 123 resource projects, are included in the calculation of both the RES and No RES plans. The inclusion of the entire cost of these resources means that the incremental costs of these renewable resources are excluded from the retail rate impact calculation. So, CF&I and Climax conclude that Public Service is collecting money from customers to acquire energy from these renewable resources and the RECs generated by them for RES compliance, but the money spent on those resources is not considered when the retail rate impact of the proposed compliance plan is calculated. CF&I and Climax conclude that the exception for Section 123 resources could allow a utility to meet the RES without any consideration of the retail rate impact by using only Section 123 resources, regardless of cost.

123. CF&I and Climax point to Hearing Exhibit No. 28 as indicating that the 2 percent RESA rider does not pay for any of the incremental costs of many of the resources to meet the RES, such as several wind farms that became operational in 2007. As a result, the 2 percent RESA rider covers the incremental costs of certain wind farms and solar acquisitions, but not the incremental costs of other operational wind farms used for RES compliance, the outcome of which is that the total amount spent on pursuing the RES mathematically exceeds the 2 percent collected through the RESA rider. Because revenue from the 2 percent RESA rider covers only a portion of the incremental costs of resources being used to meet the RES, CF&I and Climax conclude that the remainder of the incremental costs associated with renewable acquisition is recovered from customers in full through the ECA.

124. In order to remedy the situation described above, CF&I and Climax propose that Public Service be required to reduce acquisitions of eligible energy resources to ensure compliance with the retail rate impact cap in accord with Rule 3661(h)(IV).

125. Trinchera Ranch expresses its own concerns regarding the retail rate impact. Trinchera Ranch submits that the calculation of the projected incremental costs relies on outdated and inaccurate assumptions. By continuing to rely on outdated assumptions, Trinchera Ranch asserts that the projected incremental costs have been substantially underestimated, which has allowed Public Service to validate compliance with the 2 percent retail rate impact cap, while the actual impact to ratepayers includes incremental costs not captured by the RESA. Trinchera Ranch takes the position that the costs associated with renewable resource acquisitions under the RES should be modeled as accurately as possible. In order to achieve accuracy and fairness, Trinchera Ranch proposes that the Commission review the assumptions underlying the incremental cost calculations on a biannual basis, and approve a lock-down of incremental costs

only if those incremental costs are based on figures as of the date of the order approving the lock-down.

126. In addition, Trinchera Ranch recommends that Public Service be required to model the accuracy of the locked-down incremental costs with actual "real world" incremental costs, and provide an annual report detailing the total cost paid by ratepayers for renewable resources. For instance, Trinchera Ranch is also concerned with the carbon proxy cost and natural gas assumptions utilized by Public Service. While Trinchera Ranch acknowledges that Public Service has correctly not assumed a carbon proxy cost here, it is nonetheless troubled by the natural gas figures the Company utilized to calculate the incremental costs. Trinchera Ranch believes that those costs are too high. It argues that Public Service should be required to use updated gas price figures in determining any lock-down of incremental costs in this proceeding.

127. Trinchera Ranch takes its position a step further by contending that Public Service should also include the cost of coal plant cycling in determining the lock-down of incremental costs. Trinchera Ranch argues that this is important since the great majority of resources proposed to be locked-down are wind resources, and those are the primary resources creating coal plant cycling costs. Trinchera Ranch claims that the Company can provide this information here since it is readily available and was included in Public Service's modeling in its 2014 RES Compliance Plan.[20]

128. Trinchera Ranch also agrees with Staff that transparency to ratepayers is important, and as such, information regarding the total annual cost paid by ratepayers for a given renewable resource should be publicly available.

[20] *See*, Hearing Transcript, Vol. II, p. 61, line 23 to p. 62, line 7.

129. Staff as well believes that it is important for the Commission, as well as ratepayers, to understand that ratepayers are paying the total cost of renewable energy and not just the incremental costs recovered through the RESA. For this reason, Staff advocates for requiring Public Service to list the annual cost of renewable energy resources listed in Table 4-3 of Hearing Exhibit No. 1B, along with the corresponding cost recovery mechanism and costs. Staff asserts that the distinction between recovery of renewable energy costs from RESA revenue and recovery of costs from the ECA is significant because the renewable energy costs projected by Public Service[21] are not exclusively recovered from RESA revenue or identified as ECA costs.

130. It is Staff's contention that awareness of the actual costs of renewable energy acquisitions will assist the Commission in the evaluations and review of applications and compliance plans to ensure that the acquisition of renewable energy resources are completed in a cost effective manner.

131. Staff also argues that Public Service's modeled acquisition and incremental costs do not reflect the total annual cost to ratepayers. Staff asserts that the total cost is not exclusively recovered through the RESA rider, nor is it subject to the retail rate impact. Rather, the RESA reflects only the projected incremental costs. The difference between the incremental costs and the total costs is shrouded through the recovery of the balance of the costs through the ECA. Staff figures that the actual cost of the avoided conventionally generated energy is much lower than what Public Service's modeling assumptions suggest. Staff asserts that to compensate, Public Service trues up its modeled avoided costs through the ECA, which effectively circumvents the 2 percent retail rate impact limitation.

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[21] *See*, Hearing Exhibit No. 1B, Table 7-3, Column F.

132. Regarding the locked-down eligible energy resource costs, Staff contends that Public Service artificially lowers the incremental costs of new or additional renewable energy resources because it includes the same resource in both the RES and No RES portfolios, which in turn effectively increases the cost of each portfolio.

133. The OCC asserts that the Commission should set a maximum overall dollar limit on renewable energy expenditures in 2012 and 2013. According to the OCC, the Commission should require Public Service to not spend more than the projected cost of acquisition of the renewable resources contained in its approved 2012 RES Compliance Plan, which means capping both the capacity and the costs at Public Service's projected amounts, adjusted to reflect the Commission's decision on how many MWs of solar DG may be acquired.

5. Findings and Conclusions

134. Public Service projected the retail rate impact of its acquisition of eligible energy resources consistent with the methodology approved by the Commission in the Company's 2007 ERP. In line with this methodology, Public Service included updated coal, gas, and load forecasts. However, the Company did not assume a carbon proxy cost due to the lack of current carbon legislation either in place or proposed for 2012 or 2013.

135. The concerns raised by the parties concerning the calculation of the retail rate impact are well-founded. Nevertheless, they have been addressed by the Commission in one form or another in past dockets and rulemaking proceedings. Commission Rule 3661(h)(III) provides that eligible energy resources acquired prior to July 2, 2006 are to be included in both the RES and No RES plans. Additionally, eligible energy resources acquired in an ERP as new technologies or demonstration projects under § 40-2-123, C.R.S., are also to be included in both the RES and No RES plans.

136. Further, as Public Service points out, the Commission has reviewed these contrasting positions and, through compromise, reached a solution in Rule 3661(h)(V), which allows a QRU to choose to lock down these ongoing annual net incremental costs until its next compliance filing, or as here, its 2015 ERP. At that time, the Rule provides that the costs are unlocked and reset to reflect changes in methods and assumptions used by the QRU under the ERP rules. In Decision No. C09-0990, Docket No. 08R-424E, issued September 9, 2009, the Commission found that unlocking and resetting the costs based on updated projections of the costs and benefits of the RES and No RES plan "strikes a reasonable balance between the frequent updates in net incremental costs as supported by Staff and the long-term lock down of costs advocated by Public Service …"[22]

137. While the issues raised by the parties above have noteworthy merit regarding the viability of the cost assumptions underlying the modeling of the RES and No RES plans, it is apparent that QRUs must have some semblance of certainty in order to plan several years out for the acquisition of eligible energy resources. It is also clear that modeled costs most likely will not reflect actual costs under the lock down process. However, this is mitigated somewhat by requiring periodic review and a resetting of those costs. The Commission found this trade off necessary in order to not only provide the QRU some certainty in its eligible energy resource acquisition planning, but also to reduce the need to engage in extensive litigation regarding those costs each time a Compliance Plan is presented for approval.

138. It is found that despite the well-founded arguments raised by the parties regarding the Retail Rate Impact and the lock down of eligible energy incremental costs, there is no reason to deviate from Rules 3661(h)(III) and (V) at this time. Consequently, Public Service's

[22] Decision No. C09-990 at 11.

methodology for calculating the retail rate impact and the lock down costs will be approved without modification.

H. Estimated Level of Advanced Funds for 2012 and 2013

139. Pursuant to § 40-2-124(1)(g)(I)(B), C.R.S., Public Service may advance funds from year to year to augment the RESA for the acquisition of more eligible energy resources. The amounts the Company proposes to advance in this Compliance Plan for 2012 and 2013 are illustrated in Hearing Exhibit No. 1B, Vol. 2, Table 7-3, Column V, labeled as Annual Excess/(Deficiency). For 2012, the deficiency amount is estimated at $25,725,407. For 2013, the deficiency amount is estimated at $4,455,892.

140. In accordance with § 40-2-124(1)(g)(B), C.R.S., Public Service also seeks a finding that the specific amount of funds to be advanced in 2012 and 2013 is prudent.

141. Public Service's calculations for 2012 and 2013 derive from the SR program customer incentives and acquisitions targets described in its Recommended Plan. As discussed above, the targeted levels of Retail DG acquisitions set forth in the Recommended Plan are approved, while the incentive levels are adjusted upward to transition the PBI levels from the 11A-135E Settlement levels to the levels proposed by 2014. The change in the PBI levels will as a result, cause the Company's spending to deviate from the deficiency amounts outlined by the Company.

142. The funds advanced by Public Service consistent with the new PBI incentives established by this Order for 2012 and 2013 will be approved. As discussed elsewhere in this section, it is acknowledged that the negative RESA deferred balance is of concern to the Commission as it is to several of the parties to this proceeding. However, under the circumstances presented here, the deficiency amounts are reasonable. While several parties

take issue with the methodology employed by Public Service in the calculation of the Retail Rate Impact, as well as the data and costs underlying the modeled costs and assumptions, as found elsewhere in this Decision, there is nothing to indicate that the Company failed to follow the prescribed methodologies under the Commission's RES Rules.

143. With respect to Public Service's request for a finding of prudence for the funds to be advanced in 2012 and 2013, it is found that such a finding is not required. Rule 3657(c) of the Commission's RES Rules holds that Public Service's actions under an approved compliance plan shall carry a rebuttable presumption of prudence.

144. Staff recommended that Public Service be required to list the annual costs of renewable energy resources along with the corresponding cost recovery mechanism and costs in annual compliance reports and plan filings. Public Service did not object to this requirement.

145. Staff's assertions regarding providing ratepayers with transparency of the total costs they are paying for renewable energy is compelling. Staff's recommendation is reasonable and provides a layer of transparency to the renewable energy costs. As a result, Public Service will be required to make an annual compliance report and plan filing which details the annual costs of renewable energy resources along with the corresponding cost recovery mechanism. The Company shall discuss these filings with Staff in order to determine the proper level of information to be provided. The Commission will rely on Staff's discretion in determining the content of these compliance filings. The first filing shall be due no later than 30 days from the date of a final Commission Decision in this proceeding.

I. Solar*Rewards Community Bill Credit

146. In order to implement the SRC program, Public Service proposes a Solar*Reward Community Service tariff (Schedule SRC) which establishes the billing credit that will be

applied to a community solar garden subscriber's electric bill. The billing credit will be based on the service class under which the subscriber purchases electricity from Public Service. Schedule SRC is partitioned into five sections. Section (1) Applicability defines eligibility and specifically excludes area/street lighting or resale service customers from participation. Section (2) Definitions defines all rates, terms, and conditions of Schedule SRC, including definitions for Service Period, Demand-Side Management Component, SRC Allocation, SRC Non-base Rate Adjustments, SRC Producer, SRC Subscriber, Total Rate Adjustment Component, TCA Component, Total Aggregate Retail Rate (TARR), and Transmission and Distribution costs. Section (3) SRC Credit Rate Calculation lists the variable used to calculate the SRC Credit. Section (4) SRC Credit Billing details how Public Service calculates and applies the SRC Credit to each customer's bill. Section (5) Rules and Regulations details what is expected of the SRC Producer in such matters as contract compliance, equipment installation and maintenance, and notification requirements related to service failure or damage to Company equipment.

147. The SRC Credit Rate calculation is depicted in the chart on page 3 of Section 9, Vol. 1, Hearing Exhibit No. 1A.

148. Public Service witness Brockett offered testimony regarding the methodology proposed by the Company to calculate the credit per kilowatt-hour that participants in Public Service's SRC program will receive on their electric bills. Mr. Brockett testified that the credit was calculated pursuant to § 40-2-127(5)(b)(II), C.R.S., which provides in relevant part:

> The net metering credit shall be calculated by multiplying the subscriber's share of the electricity production from the community solar garden by the qualifying retail utility's total aggregate retail rate as charged to the subscriber, minus a reasonable charge as determined by the commission to cover the utility's costs of delivering to the subscriber's premises the electricity generated by the community

solar garden, integrating the solar generation with the utility's system, and administering the community solar garden's contracts and net metering credits.

149. Public Service represents that its proposed SRC bill credit is faithful to the statutory method of calculating the credit. Mr. Brocket characterizes the SRC Credit calculation as "charging customers for 100 percent of the embedded delivery costs per kWh allocated to their respective rate classes, plus administrative costs and the costs of public benefits programs which include RESA and DSMCA."

1. Intervenor Positions

150. Boulder advocates for a SRC bill credit set at a level that will encourage subscriber participation. Boulder is of the opinion that the bill credit proposed by Public Service is unnecessarily complex and insufficient to encourage low income participation, particularly since subscribers may incur upfront costs to subscribe to a community solar garden. Boulder believes it is inappropriate for the bill credit to be reduced by subtracting full transmission and distribution charges, demand-side management (DSM) charges, or the rider for the RESA.

151. Regarding transmission and distribution charges, Boulder argues that SRC program participants should not be charged for transmission costs if they are served by the same substation to which their solar garden is connected. Rather those subscribers should only pay for transmission and distribution charges they actually incur. It requests that the Commission reject the proposal to subtract transmission and distribution charges from the TARR in calculating the bill credit.

152. Boulder also takes issue with the Company's plans to subtract the costs of DSM programs from the SRC billing credit. According to Boulder, the community solar gardens statute and Rule 3665(c)(II) provide that the subscriber's bill credit can be reduced only by a

"reasonable charge" for the cost of delivery, integration, and administration. In order to make the SR and SRC programs comparable, Boulder urges the Commission to reject Public Service's proposal to subtract the DSM costs from the TARR in calculating the bill credit.

153. Boulder also takes the position that community solar garden participants contribute their fair share towards renewable energy programs through significant investments in solar gardens infrastructure. As such, it opposes Public Service's proposal to charge SRC subscribers their "fair share" by reducing the TARR by the RESA rider in the calculation of the bill credit. Boulder notes that residents and businesses make significant upfront investments for on-site solar and expect similar investments for solar gardens with the PBIs proposed for the SRC program.

154. IREC and VS also propose several changes to the Company's proposal for calculating the SRC Credit. These parties maintain that the proposed changes are necessary to ensure that the subscribers to a community solar garden receive a fair SRC Credit consistent with HB 10-1342.

155. In making the proposed amendments to the SRC Credit calculation, IREC and VS witness Beach offered up his interpretation of § 40-2-127(5)(B)(II), C.R.S, specifically, the term "reasonable charges." Mr. Beach offered that the term "reasonable" can mean "reasonable to fulfill the purpose of the statute," which he interprets as implementing a successful community solar gardens program.[23] He also defines "reasonable" as the balancing of "the costs borne by solar garden subscribers versus the costs that are born by nonparticipating ratepayers."[24] Additionally, Mr. Beach interprets "reasonable" as involving a balance of the costs to the utility

[23] Transcript. Vol. II, p. 175, ll. 3-6.
[24] *Id*. at p. 175, ll. 7-13.

against the benefits that community solar gardens will provide to the utility in terms of reduced costs (particularly avoided generation capacity costs) over the long-term.[25]

156. Based on this interpretation of "reasonable," IREC and VS propose changes to the Company's SRC billing credit. First, they argue that the difference between Public Service's marginal and embedded generation costs should be subtracted from Public Service's proposed reasonable charge for community solar garden generation. Mr. Beach calculated the marginal costs of generation utilizing a similar methodology as the Company from its last rate case. IREC and VS represent that this approach will create a more robust SRC program and will allow the Company to fully recover its costs.

157. Second, IREC and VS suggest that, if the solar garden and a subscriber are served from the same distribution substation, the delivery of the solar garden generation should not require use of Public Service's transmission system, and the SRC Credit for that subscriber should be increased by Public Service's embedded transmission costs. IREC and VS find this reasonable since community solar garden subscribers should not be required to pay for the transmission system if it is not used in delivering their energy. IREC and VS state that this provision is consistent with the Company's existing rate design, that already reflects whether a customer uses the transmission system only, or both the transmission and distribution systems.

158. Third, IREC and VS suggest that if their proposed adjustments cause the SRC Credit to exceed the TARR, the SRC Credit rate should be capped at the TARR. According to Mr. Beach, it is reasonable to provide community solar garden subscribers with an SRC Credit rate set at the TARR, as this level of credit is comparable to the credit available to

[25] Hearing Exhibit No. 20, Beach Answer Testimony, p. 5, ll 16-17.

regular net metered customers who install solar on their own premises.[26] Mr. Beach notes that for four of the six Public Service rate classes, such a cap would result in the SRC Credit rate being less than the long-run marginal cost of generation, which means that non-participating ratepayers would receive a net benefit if subscribers on these rate schedules were to invest in community solar gardens.

159. IREC and VS also advocate for the use of long-run marginal costs to calculate the reasonable charge component of the SRC Credit. They argue that use of long-run marginal costs is reasonable, and more appropriate to calculation of that reasonable charge and will result in a more effective and successful SRC program.

2. Public Service's Response

160. Public Service contests Mr. Beach's recommendations. Mr. Brockett maintains that the Company's approach to the SRC Credit is more consistent with the community solar gardens statute in that it provides for a credit per kWh equal to the TARR minus a reasonable charge for delivering energy from the SRC facility to the subscriber. On the other hand, Public Service argues that Mr. Beach's approach derives class credits based on estimates of avoided costs, which is inconsistent with the statutory directive.

161. Public Service further argues that Mr. Beach's approach utilizing the long-run marginal cost as the proxy for the avoided cost has merit when a utility's actual and targeted reserve margins do not vary significantly. However, here, the Company argues that it has no need for additional generation capacity over the next few years. Should long-run marginal costs be utilized in this situation, Public Service supposes that they may overstate the true avoided cost.

[26] *Id*. at p. 6, ll. 9-13.

162. Although Public Service agrees in principle with Mr. Beach that the SRC credit should include a recognition of avoided transmission capacity costs, it nonetheless finds that Mr. Beach has overstated the avoided transmission capacity cost. Public Service also believes that the magnitude of the transmission credit does not justify the additional work required to implement it.

163. In the alternative, Public Service recommends that should the Commission direct the Company to implement a transmission credit, such credit should be set at 50 percent of the adjusted credit described by Mr. Brockett in his rebuttal testimony (Hearing Exhibit No. 12, page 9, lines 13 – 20). Mr. Brockett opines that transmission costs are largely collective-system capacity costs driven by the same coincident peak loads that drive the need for generation capacity. As a result, it is Mr. Brockett's opinion that Mr. Beach should have applied an adjustment of 59 percent to the long-run marginal cost of generating capacity when deriving an avoided transmission cost. This approach would result in an avoided transmission cost for residential customers of $0.0032/kWh.

164. Regarding Mr. Beach's proposal to cap the Credit at the class TARR, Public Service agrees with the need for caps on class Credits, but only if they are based on avoided costs. Any cap should be the TARR, minus the recovery of DSM costs through base rates and the demand-side management cost adjustment (DSMCA), minus the RESA, according to Public Service. Such an approach, in the estimation of the Company, would ensure that subscribers at the very least do not avoid their responsibility to pay for both their administrative costs and their share of Public Service's public benefits programs. However, Public Service particularly notes that under its approach, there should be no need for a cap since that methodology ensures that the credit will not relieve subscribers of their responsibility to defray RESA and DSM costs.

165. Public Service revised the SRC tariff since the filing of its direct case based on Commission directives that occurred in the interim. First, the Company initially proposed that uniform credit be applied to each subscriber in a given rate class. However, Public Service notes that the Commission indicated a preference for a customer-specific credit for customers who are assessed demand charges based on the specific customer's billing.[27] The modified tariff removes any reference to class-specific credit for demand-metered classes and explains how the credit will be determined on a customer-by-customer basis.

166. Second, the SRC tariff provides that the credits will be updated no more than once per year, similarly based on a Commission directive.[28] Public Service proposes to file a "less than statutory notice" application to update the annual credit by December 15 of each year for approval of new credits to become effective on January 1 of the following year. Creditsimplemented in 2012 will be applied for upon a final Commission Decision in this proceeding.

3. Findings and Conclusions

167. Public Service's proposed derivation of the SRC billing credit closely follows the calculation specified in § 40-2-127(5)(b)(II), C.R.S., and is approved with the exception of the adjustments for DSM-related costs. The only reduction from the investor-owned QRU's TARR contemplated by the community solar gardens statute entails the costs of delivering electricity which DSM programs do not generally relate. With this modification, the SRC tariff and the methodology for determining the credits provided customers for their share of solar garden

[27] Commission Decision Nos. C11-0991 issued September 14, 2011 and C11-1172 issued November 1, 2011, Docket No. 10R-674E.

[28] *Id.*

generation will be approved. Public Service's proposal to update the tariff on an annual basis will also be approved.

168. There will be no additional transmission credits based on the locations of subscriber's billing premises in relation to the community solar garden. Such adjustments undermine the straightforward approach for compensating subscribers through billing credits based on the rates otherwise charged to the subscriber for the renewable energy produced by the community solar garden.

169. Customers receiving billing credits as a result of participation in the SRC program will be subject to the RESA charge, since § 40-2-124(1)(g)(IV)(B), C.R.S., provides that customers who install DG shall continue to contribute their fair share to the RESA even if such contribution results in a charge that exceeds 2 percent of such customers' annual electric bills. Contrary to Boulder's assertions, continuing contributions to the RESA are appropriate from subscribers to community solar gardens in order to support the continuing acquisition of eligible energy resources.

170. The suggested rates proposed by IREC and VS will not be adopted as their approach strays too far from the plain language of § 40-2-127(5)(b)(II), C.R.S.

J. SR Purchase Contract Language

171. Hearing Exhibit No. 1C, Vol. 3 of the Compliance Plan, includes the red-line changes Public Service proposes to its SR contracts as part of its Application. Among the changes proposed is language that states that the Company's tariffs are incorporated by reference and that, to the extent a conflict may arise between Public Service's tariff and the contract, the tariff will prevail.

172. Public Service maintains that the proposed language is not new and in fact dates back to before 2009 and appears in the SR REC Purchase Contract for Customer-Owned PV Systems Greater than 10 kW DC Nameplate Capacity, as well as the SR Contract Customer-Sited PV Systems Greater Than .5 kW and Not Exceeding 10 KW DC Nameplate Capacity.

173. By including a provision that incorporates the tariff into the REC purchase contract, Boulder argues that Public Service is seeking approval of a new provision not found in Commission rules which impairs the obligation of contracts. According to Boulder, if the proposed provision is approved, to the extent that future tariff changes conflict with the 20-year contracts that SR participants sign, those contracts will be changed, likely to the detriment of the participants. Boulder also notes that Public Service has provided no testimony regarding the need for such a sweeping change to its SR contracts.

174. Boulder expresses concern regarding several other tariff provisions as well. First, it requests that Public Service include consistent language in its contracts regarding historic or anticipated use. The definition of "retail distributed generation" states that "retail distributed generation … shall be sized to supply no more than one hundred twenty percent of the average annual consumption of electricity by the customer at that site." *See*, § 40-2-124(1)(A)(V), C.R.S. This language also appears in Commission Rules 3652 and 3664(a)(I). However, Boulder points out that in discussing the 120 percent limitation in its contracts, Public Service altered this language in several current contracts by stating that retail distributed generation "is less than 120% of historical or anticipated average annual electric consumption at the Service Address." Boulder requests that Public Service be required to revise its contracts to consistently reflect that phrase approved by the legislature and the Commission.

175. Boulder is also concerned that Public Service has introduced discretion regarding contiguous sites when it has no such discretion. Section 40-2-124(1)(A)(V), C.R.S., provides that an end-use customer's site "[shall include] all contiguous property owned or leased by the customer …" Nonetheless, Public Service has included language in certain contracts that states "[i]n making a determination that such threshold has been met, Public Service may elect to include, in its sole discretion, Customer's consumption on contiguous property." Boulder requests that this language be modified to be consistent with the statute.

176. The tariff provisions included in the SR Purchase Contracts proposed by Public Service does not appear to be new language. It is agreed that such language has appeared prior to this in the contracts mentioned by the Company above. It should also not be forgotten that in order to alter tariff language, the Company must seek approval from the Commission. Should it be found that amending specific tariff language will interfere substantially with those SR contracts, the undersigned ALJ is confident that the Commission will carefully consider the implications of such tariff language changes on those existing contract holders. As a result, it is found that the language proposed by the Company regarding tariff language versus contract provisions is appropriate and will be approved.

177. Regarding Boulder's concerns regarding language in the contracts regarding historic or anticipated use, it is found that Boulder's concerns have merit. It appears that there is a discrepancy between the statutory definition of "retail distributed generation" as found in § 40-2-124(1)(A)(V), C.R.S., and contract language discussing the 120 percent limitation. To the extent there is a discrepancy in those two definitions, Public Service will be required to correct its contract language to be consistent with the language found in § 40-2-124(1)(A)(V), C.R.S.

178. Further, it is found that a discrepancy exits regarding contract language which appears to provide discretion in addressing contiguous sites and the statutory language which does not provide such discretion. To the extent that proposed contract language addressing contiguous sites is in conflict with § 40-2-124(1)(A)(V), C.R.S., Public Service will be required to correct such language discrepancies to be consistent with language found in § 40-2-124(1)(A)(V), C.R.S.

1. Calculation of After Tax Weighted Cost of Capital

179. Public Service states that during the course of the proceeding, it determined that there is some ambiguity in Commission Rule 3660(e) as to how to calculate the Company's after tax weighted cost of capital (WACC), which is the rate applied to the RESA balance.

180. Public Service requests that the Commission interpret Rule 3660(e) to require the use of an after-tax weighted average cost of capital that uses the most recent authorized return on equity from the Company's most recent rate case, but is updated annually to use the Company's current cost of debt, current tax rate and current capital structure as reported in its annual Appendix A filing.

181. Public Service is of the opinion that it is appropriate to annually update the WACC in this manner and that it would be consistent with and better implement Rule 3660(e).

182. Public Service's most recently authorized return on equity is a conspicuous value established in a Commission Order for ratemaking purposes. In contrast, current tax rates and current capital structures as reported in the Company's Appendix A may not typically be approved for ratemaking purposes, and there is a possibility that these inputs to the Company's proposed calculation of the after tax WACC could be disputed. However, the calculation of interest charges paid on RESA balances to the Company's shareholders is largely an accounting

exercise that can be sufficiently reviewed by Staff and others pursuant to various RES-related filings without delaying any proposed change rates such as the RESA surcharge (presently set at 2 percent) or other rate riders that change much more frequently (such as the ECA). Given the opportunity for safeguard reviews of the calculation and the low probability that an updated annual calculation will upset any highly time-sensitive rate filing, the Company's proposal to update its after tax WACC each year will be approved.

K. Other Requested Modifications to the Compliance Plan

183. SA proposes that Public Service be required to establish a regular series of public meetings with stakeholders to discuss the rate of acquisition of solar resources and incentive level adjustments in order to best determine how to plan for future changes and ensure there is nothing unexpected, such as the closure of the program in 2011. SA proposes that milestones recommended by the solar industry can be adjusted at these meetings and provide for additional monitoring in a manner beneficial for Public Service and its ratepayers. Should any Commission Rules impede the ability to establish milestones in the SR program going forward, SA requests that such Rules be waived.

184. In addition, COSEIA suggested that certain projects be allowed to exceed 12 months for completion.

185. It is found that implementation of these recommendations is not necessary at this time and will not be implemented.

186. In accordance with § 40-6-109, C.R.S., it is recommended that the Commission enter the following order.

III. ORDER

A. The Commission Orders That:

1. Public Service Company of Colorado's (Public Service) 2012 Renewable Energy Compliance Plan is approved as modified by this Decision.

2. Public Service shall not be permitted to carryover any megawatts in the remaining steps from the 11A-135E Settlement Agreement.

3. Public Service shall modify its proposed performance based incentives as set out in Table 1 at Paragraph No. 94 to this Decision.

4. The lock down incremental costs of Cedar Creek Wind II, Cedar Point Wind, the 2011 Wind RFP 200 MW Wind, and the San Luis Solar PV shall be approved. The lock down of these incremental costs will apply to the resources listed until Public Service's next compliance plan filing, which is its 2015 Electric Resource Plan.

5. Public Service's proposed retail rate impact calculations and cost recovery mechanism shall be approved.

6. Public Service's proposed funds to be advanced for 2012 and 2013 are approved consistent with the modifications to the performance based incentives set out in Table 1 at Paragraph 94 to this Decision.

7. Public Service shall make a compliance filing within 30 days of a final Commission Decision in this matter, setting out the amended levels of advanced funds for 2012 and 2013 under the approved performance based incentives.

8. The request by Public Service for a finding of prudence for the amount of funds to be advanced from year to year to augment the amount collected from retail customers under the Renewable Energy Standard Adjustment is denied consistent with the discussion above.

9. No later than 30 days from the date of a final Commission Decision in this matter, Public Service shall make a compliance filing detailing the annual costs of renewable energy resources, along with the corresponding cost recovery mechanism. Public Service shall work with Commission Staff to coordinate the details of the filing.

10. The Solar Rewards Community Bill Credit rate proposed by Public Service shall be approved with the exception of certain adjustments for demand-side management related costs as discussed above.

11. To the extent that there is a discrepancy between the statutory definition of "retail distributed generation" as found in § 40-2-124(1)(A)(V), C.R.S., and contract language discussing the 120 percent limitation, Public Service shall correct its proposed Solar*Rewards Purchase contract language to conform to the statutory language.

12. To the extent that proposed Solar*Rewards contract language addressing contiguous sites is in conflict with § 40-2-124(1)(A)(V), C.R.S., Public Service shall correct such language discrepancies to be consistent with the statutory language.

13. The proposal of Public Service to annually update its after tax weighted cost of capital shall be approved.

14. The motion of the Colorado Solar Energy Industries Association to accept its Statement of Position out of time is granted.

15. This Recommended Decision shall be effective on the day it becomes the Decision of the Commission, if that is the case, and is entered as of the date above.

16. As provided by § 40-6-106, C.R.S., copies of this Recommended Decision shall be served upon the parties, who may file exceptions to it.

a.) If no exceptions are filed within 20 days after service or within any extended period of time authorized, or unless the recommended decision is stayed by the Commission upon its own motion, the recommended decision shall become the decision of the Commission and subject to the provisions of § 40-6-114, C.R.S.

b.) If a party seeks to amend, modify, annul, or reverse a basic finding of fact in its exceptions, that party must request and pay for a transcript to be filed, or the parties may stipulate to portions of the transcript according to the procedure stated in § 40-6-113, C.R.S. If no transcript or stipulation is filed, the Commission is bound by the facts set out by the administrative law judge; and the parties cannot challenge these facts. This will limit what the Commission can review if exceptions are filed.

17. If exceptions to this Recommended Decision are filed, they shall not exceed 30 pages in length, unless the Commission for good cause shown permits this limit to be exceeded.

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

PAUL C. GOMEZ

____
Administrative Law Judge

ATTEST: A TRUE COPY

Doug Dean,
Director