Agenda 23 19: Item No. 28 Draft Order for discussion at utility agenda.

THIS ORDER IS NOT A FINAL ORDER AND MAY BE SUBSTANTIALLY REVISED PRIOR TO ENTRY OF A FINAL ORDER BY THE PUBLIC UTILITIES COMMISSION OF NEVADA

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the third amendment to its 2018 Joint Integrated Resource Plan to update and modify the renewable portion of the Supply-Side Action Plan and the Transmission Action Plan.	)	Docket No. 19-06039

At a general session of the Public Utilities Commission of Nevada, held at its offices on December 4, 2019.

PRESENT: Chairwoman Ann Pongracz
Commissioner C.J. Manthe
Commissioner Hayley Williamson
Assistant Commission Secretary Trisha Osborne

[PROPOSED] ORDER

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

I. INTRODUCTION

On June 24, 2019, Nevada Power Company d/b/a NV Energy, ("NPC") and Sierra Pacific Power Company d/b/a NV Energy ("SPPC") (collectively, "NV Energy") filed with the Commission a Joint Application, designated as Docket No. 19-06039, for approval of the third amendment to their 2018 Joint Integrated Resource Plan ("IRP") to update and modify the renewable portion of the Supply-Side Action Plan and the Transmission Action Plan ("Application").

On October 18, 2019, NV Energy, Regulatory Operations Staff ("Staff"), the Attorney General's Bureau of Consumer Protection ("BCP"), Nevadans for Clean Affordable Reliable Energy ("NCARE"), Solar Partners XI, LLC ("Arevia"), and Interwest Energy Alliance ("Interwest") (collectively, the "Parties") filed a partial issue stipulation with the Commission, which resolves the issues related to three renewable energy power purchase agreements ("PPAs") and associated network upgrades but does not resolve issues related to a new Apex Substation or upgrades at the Machacek Substation.

II. SUMMARY

The Commission approves the Partial Issue Stipulation, attached hereto as Attachment 1, as modified by the Parties on the record, and grants in part and denies in part the Application as delineated by this Order.

III. PROCEDURAL HISTORY

- On June 24, 2019, NV Energy filed a Joint Application pursuant to the Nevada Revised Statutes ("NRS") and the Nevada Administrative Code ("NAC") Chapters 703 and 704, including, but not limited to, NRS 704.741 through 704.751 and NAC 704.9005 through 704.9525.

- Staff participates as a matter of right pursuant to NRS 703.301.

- On June 28, 2019, BCP filed a Notice of Intent to Intervene pursuant to Chapter 228 of the NRS.

- On July 10, 2019, the Commission issued a Notice of Joint Application and Prehearing Conference.

- On July 29, 2019, NCARE filed a Petition for Leave to Intervene ("PLTI").

- On July 30, 2019, Arevia filed a PLTI.

- On July 31, 2019, Northern Nevada Industrial Electric Users ("NNIEU") and Interwest each filed a PLTI.

- On August 6, 2019, the Presiding Officer held a prehearing conference in accordance with NAC 703.655. NV Energy, Staff, BCP, NCARE, Arevia, NNIEU, and Interwest made appearances. A procedural schedule, discovery procedures, and the PLTIs were discussed.

- On August 8, 2019, the Commission issued Orders granting the PLTIs of NCARE, Arevia, NNIEU, and Interwest.

- On August 12, 2019, the Commission issued a Procedural Order, establishing the procedural schedule and discovery procedures for this docket.

- On September 6, 2019, NV Energy filed an Errata to the Application.

- On September 13, 2019, the Commission issued Procedural Order No. 2 and an Amended Notice of Hearing, modifying the hearing date.

- On October 18, 2019, the Parties filed a Partial Issue Stipulation (the "Stipulation") with the Commission.

• On October 21, 2019, NNIEU filed a letter with the Commission, requesting to be excused from the hearing and stating that NNIEU did not oppose the Stipulation.

IV. JOINT APPLICATION

A. Stipulation

Parties' Position

1. The Parties recommend that the Commission accept the Stipulation as modified by the Parties on the record, grant NV Energy's request to amend its 2019-2021 Supply-Side Action Plan, allow NV Energy to enter into the three renewable PPAs requested, and grant NV Energy's request to amend its 2019-2021 Transmission Action Plan. (Ex. 1 at 3-5; Tr. at 49.)

Three New Renewable PPAs

2. The Parties agree that the Commission should approve NV Energy's request to amend its 2019-2021 Supply-Side Action Plan and enter into three new renewable PPAs as follows:

a. The Parties request that the Commission approve a PPA between NPC and Southern Bighorn Solar Farm for 300 megawatts ("MW") of solar photovoltaic ("PV") generation. (Exhibit 1 at 3.) The Parties state that this PPA would also provide an additional 135 MW of capacity from co-located battery storage. (*Id.*) The Parties agree that 40 percent of the portfolio energy credits, energy, capacity, and costs will be allocated to SPPC and the remaining 60 percent will be allocated to NPC. (*Id.*) The Parties expect commercial operation of Southern Bighorn Solar Farm to commence by September 1, 2023. (*Id.*)
b. The Parties request that the Commission approve a PPA between NPC and Moapa Solar for 200 MW of solar PV generation. (*Id.*) The Parties state that the PPA also provides an additional 75 MW of capacity of co-located battery

storage. (*Id.*) The Parties agree that 70 percent of the portfolio energy credits, energy, capacity, and costs will be allocated to SPPC and the remaining 30 percent will be allocated to NPC. (Ex. 1 at 3-4.) The Parties expect the commercial operation of Moapa Solar to commence by December 1, 2023. (Ex. 1 at 4.)

c. The Parties request that the Commission approve a PPA between NPC and Gemini Solar for 690 MW of solar PV generation. (*Id.*) The Parties state that this PPA will also provide an additional 380 MW of capacity from co-located battery storage. (*Id.*) The Parties agree that 40 percent of the portfolio energy credits will be allocated to SPPC and the remaining 60 percent will be allocated to NPC. (*Id.*) The Parties agree that NV Energy, Staff, and BCP will meet to discuss the process to annually price/value and transfer the portfolio energy credits from NPC to SPPC. (*Id.*) The Parties expect the commercial operation of Gemini Solar to commence by December 1, 2023. (*Id.*)

3. The Parties state that Commission approval of the PPAs will benefit both existing and future customers. (*Id.*) The Parties agree that the Commission's approval of the three requested PPAs "does not constitute Commission approval to use any portion of the energy and pricing associated with the three PPAs in a future optional pricing program, or any other tariff, if filed with the Commission" and that "nothing in [the Stipulation] precludes a party from opposing any future optional pricing program or challenging the resources that may be included in such an optional pricing program." (Ex. 1 at 4-5.)

<u>Appendix A to the Joint Dispatch Agreement ("JDA")</u>

4. Paragraph Two of the Stipulation reads as follows:

> The Parties agree that Appendix A to the Joint Dispatch Agreement ("JDA"), approved in Docket No. 19-05001, shall be amended to add reference to the capacity and cost allocations of Southern Bighorn Solar Farm and Moapa Solar agreed to above, and to remove reference the specific allocation of the six power purchase agreements that were approved in Docket 18-06003. The Parties acknowledge that the Commission's modified final order in Docket No. 18-06003 directed the Companies' to allocate the costs of the six power purchase agreements 40 percent to Sierra and 60 percent to Nevada Power, and did not specify that capacity of the projects should also be allocated. The Parties agree that the Commission should direct the Companies to file an alternative mechanism with the Commission to allocate the costs of the six power purchase agreements, without using the JDA.

(*Id.*)

5. During the October 23, 2019, hearing, the Parties provided clarity regarding the meaning and intent of Paragraph 2 of the Stipulation. (*See* Tr. at 17-51.) The Parties agreed to the following clarifications and related obligations:

a. The Parties will work collaboratively to develop a mechanism for treatment of the six PPAs approved by the Commission in Docket 18-06003, which they seek to remove from Attachment A of the JDA. (Tr. at 49);

b. Within 90 days of the Commission's final order in this proceeding, NV Energy shall file a petition for Commission approval to remove from Attachment A of the JDA the six PPAs approved by the Commission in Docket No. 18-06003 and to assign the capacity associated with each of these PPAs to the contracting utility. NV Energy will request Commission approval to add the Southern Bighorn Solar Farm PPA and the Moapa Solar PPA to Attachment A of the JDA and allocate the portfolio energy credits, energy, costs, and capacity associated with these two contracts as agreed to in the Stipulation. (Tr. at 25-26, 49-50.)

c. In the instant docket, NV Energy will update each utility's Loads and Resources Tables to reflect relevant changes pursuant to the Stipulation. (Tr. at 27, 49-51.)

6. NV Energy further clarified that it will seek approval of the Federal Energy Regulatory Commission ("FERC") for the proposed changes to the JDA following Commission approval of these changes. (Tr. at 29.)

2019-2021 Transmission Action Plan

7. The Parties request that the Commission approve NV Energy's requests to amend its 2019-2021 Transmission Action Plan, including:

a. An expenditure of approximately $1.3 million to construct network upgrades needed to support the interconnection of the Moapa Solar project at the Harry Allen Substation;

b. An expenditure of approximately $3.67 million to construct network upgrades needed to interconnect the Southern Bighorn Solar Project at the Reid Gardner Substation; and

c. An expenditure of approximately $9.93 million to construct network upgrades needed to support the interconnection of the Gemini Solar project at the Crystal 230-kilovolt ("kV") Substation.

(Ex. 1 at 5.)

Confidential Information

8. The Parties agree that the Commission should approve NV Energy's request to maintain the confidentiality of certain information contained in its filing for at least five years. (*Id.*)

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Commission Findings and Discussion

9. The Commission approves the Stipulation as modified by the Parties on the record as detailed above.

10. Accordingly, consistent with the modifications agreed upon by the Parties at the October 23, 2019, hearing, the Commission memorializes the following modifications made to Paragraph 2 of the Stipulation:

a. The Parties will work collaboratively to develop a mechanism for treatment of the six PPAs approved by the Commission in Docket 18-06003, which they seek to remove from Attachment A of the JDA;

b. Within 90 days of the Commission's final Order in this proceeding, NV Energy shall file a petition with the Commission for approval to remove the six PPAs approved by the Commission in Docket No. 18-06003 from Attachment A of the JDA and to assign the capacity associated with each of these PPAs to the contracting utility;

c. NV Energy shall request Commission approval to add the Southern Bighorn Solar Farm PPA and the Moapa Solar PPA to Attachment A of the JDA and to allocate the portfolio energy credits, energy, and capacity associated with these two contracts as agreed upon in the Stipulation;

d. In the instant docket, NV Energy will update each utility's Loads and Resources Tables to reflect the relevant changes resulting from this Docket; and

e. NV Energy shall seek approval of the FERC for the proposed changes to the JDA upon Commission approval of the above-referenced modifications to the JDA.

11. The Parties state that the clarifications and obligations described above will, through this Order, modify the Stipulation if "included in a proposed order in this proceeding." (*See* Tr. at 52.) Parties

12. Accordingly, with the modifications to the Stipulation set forth in Paragraph 10, the Commission finds that the Stipulation complies with NAC 703.845, in that it settles only issues relating to the instant proceeding and does not seek relief that the Commission is not otherwise empowered to grant. The Commission finds that the Stipulation, as modified above with the agreement of the Parties, is a consensus resolution of the issues pursuant to the Parties' negotiations and is a reasonable recommendation and resolution of the issues related to the three PPAs[1] and associated network upgrades in this proceeding.

13. Any agreements and recommendations contained in the Stipulation, as modified above with the agreement of the Parties, but not expressly addressed herein, are either agreements by the Parties regarding matters non-essential to the disposition of this docket, or are recommendations for specific findings that do not require delineation given the Commission's acceptance of the Stipulation as modified by this Order.

B. Apex Substation

NV Energy's Position

14. NV Energy requests Commission approval of a 230-kV switchyard (the "Apex Substation") at the Apex Industrial Park. (Ex. 2 at 88, 96.) NV Energy states that the Apex Substation is necessary to accommodate load growth in the area. (*Id.* at 96.)

15. NV Energy explains that the Apex Substation would be located along the Harry-Allen-to-Grand-Teton 230-kV line, would be dual-sourced, capable of accommodating more

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[1] Specifically, the Southern Bighorn Solar Farm PPA, Moapa Solar PPA, and Gemini Solar PPA.

load growth, and would integrate better with future planning. (*Id.*) NV Energy states that the Apex Substation "would initially serve a 13 MW load, but will be expandable to accommodate additional transmission interconnections as well as two distribution transformers." (*Id.*) NV Energy argues that without the Apex Substation, long and costly distribution line extensions would be required to serve new loads in the area from existing substations. (*Id.*)

16. NV Energy states that there are currently two substations in proximity to the Apex Industrial Park – the Speedway Substation and the Gypsum Substation – which are approximately eight miles apart. (*Id.*) NV Energy explains that the Gypsum Substation serves the majority of the Apex Industrial Park and that NV Energy expects the Gypsum Substation's transformer bank to overload in 2021. (Ex. 8 at 8.) NV Energy states that the Speedway Substation is also in proximity to the Apex Industrial Park, but it anticipates that the Speedway Substation's transformer bank will overload in 2020. (*Id.*) NV Energy states that it could add more transformer banks to each substation to accommodate the future load growth, but that the line extensions required for such connections would be "a financial barrier to entry." (*Id.*)

17. NV Energy states that it would be responsible for folding the existing 230-kV Harry-Allen-to-Grand-Teton 230-kV transmission line and the construction of the Apex Substation. (Ex. 2 at 96.) NV Energy further states that the construction would include an expandable four-breaker 230-kV transmission substation. (*Id.* at 96-97.) NV Energy estimates that the Apex Substation will cost approximately $13.425 million. (*Id.* at 97.)

18. NV Energy states that a customer receiving high-voltage distribution "is responsible for the cost of the high voltage distribution line that serves its customer-owned transformer as well as the substation site and on-site improvements." (Ex. 2 at 97.) NV Energy estimates such costs would total approximately $3.2 million. (*Id.* at 98.)

19. Regarding alternatives to the Apex Substation, NV Energy acknowledges that a radial 138-kV transmission line from the Pecos Substation is "electrically feasible". (Ex. 8 at 7.) However, NV Energy states that permitting the 138-kV transmission line would be extremely difficult. (*Id.*) NV Energy states that it has "experienced significant opposition" when trying to procure permits to cross the land required for the 138-kV line. (Tr. at 69.) NV Energy further states that "it's nearly impossible to get a [138-kV] line through there, especially to meet Air Liquide's April 2021 in-service date." (*Id.* at 156.)

20. NV Energy explains that "construction of the 138-kV line would require crossing the U.S. Air Force ('USAF') Base, where the Nellis Small Arms Range is, as well as the National Guard, and in order to do that it would require approval for both of those entities." (Ex. 8 at 7; Tr. at 69.) NV Energy states that the USAF has not approved anything in proximity to the Nellis Small Arms Range. (Ex. 8 at 7; Tr. at 155-156.) Moreover, NV Energy explains that it has also faced opposition from the State and the National Guard when it has tried to procure permits to cross the land in the past. (Ex. 8 at 7.)

21. NV Energy states that without two sources, the 138-kV would be subject to both transmission-level service and distribution-level service outages for any event on the transmission line. (Ex. 8 at 8.) NV Energy explains that it cannot use the Gypsum Substation to provide two sources for the 138-kV transmission line because the Gypsum Substation does not have any available terminals. (*Id.*) NV Energy states that it did not pursue the 138-kV transmission line option because of the permitting and sourcing complications. (*Id.*)

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Staff's Position

22. Staff recommends that the Commission deny NV Energy's request to build the 230-kV Apex Substation and instead allow NV Energy to construct a 138-kV radial transmission line originating at the Pecos Substation. (Ex. 11 at 2.)

23. Staff states that constructing a 138-kV radial transmission line is a less-expensive alternative to building the Apex Substation. (Ex. 11 at 3.) Staff states that the total cost of the 138-kV radial transmission line would be approximately $12.13 million, with a cost of $10.43 million to Air Liquide and a cost of $1.7 million to NPC. (*Id.*) Staff argues that NV Energy's proposal shifts costs from Air Liquide to other transmission customers, including bundled retail customers. (*Id.*) Staff states that constructing the new 230-kV Apex Substation would cost NV Energy approximately $13.42 million and would save Air Liquide approximately $7 million compared to the 138-kV radial transmission line. (Ex. 11 at 2.)

24. Staff argues that NV Energy is trying to justify additional transmission rate base on speculative load growth and reduced line extension costs, which the interconnecting customer should bear. (Ex. 11 at 3.) Furthermore, Staff states that NV Energy does not offer any substantive information regarding why NV Energy could not complete the construction of the 138-kV radial transmission line by the deadline, other than citing historical permitting issues. (Ex. 11 at 4.)

25. Staff suggests a Rule 9 special contract alternative requiring Air Liquide to pay the radial transmission line price for the Apex Substation. (*Id.*) Staff argues that Air Liquide is "driving need" behind NV Energy's request to build the Apex Substation. (*Id.*) Staff proposes that if the 138-kV transmission line construction timeline is too long, then Air Liquide should pay the $10.43 million that the 138-kV transmission line would have otherwise cost Air Liquide

so that NV Energy could utilize that money to build the Apex Substation. (*Id.*) Staff argues that this arrangement would protect other ratepayers from paying additional costs for the Apex Substation. (*Id.*)

BCP's Position

26. BCP does not object to NV Energy's Apex proposal. (Ex. 9 at 2; Tr. at 76-78.)

NV Energy Rebuttal

27. Regarding Staff's proposal, NV Energy states that the Pecos 138-kV radial transmission line would not allow for future expansion and that the Gypsum Substation shares the capacity limitations of the Pecos Substation. (Ex. 13 at 13.) NV Energy further states that although distribution load growth is possible on the 138-kV system, it cannot handle the distribution load growth of "large operations such as a 100+ MW data center or manufacturing facility." (*Id.*) NV Energy states that "[t]hese are the types of facilities that are expected to locate within the Apex [Industrial Park]." (*Id.*)

28. NV Energy states that the proposed Apex Substation "is a reasonable and prudent first step towards a phased approach to serving the future load of the Apex Industrial area." (Ex. 13 at 14.) NV Energy states that "the Companies have met with several developers who have potential growth from 10 MW of distribution load to 100+ MW of data center and/or manufacturing load." (Ex. 13 at 14-15.) NV Energy claims that it also has "proposals from developers for large operations" at Miners Mesa and City View. (Ex. 13 at 15.)

29. NV Energy provides that the proposed Apex Substation "... is not building for theoretic growth" and that "there are real customers ready to interconnect to the system." (Ex. 14 at 3.) NV Energy claims that the "Companies are currently aware of roughly 300 MW of new load that are currently in discussion with the Companies, with another potential 70 MW that is

less certain." (Ex. 14 at 5; Tr. at 133.) NV Energy states that its plan is "not only to serve Air Liquide, but to have a plan that can serve the whole area for long-term system planning, [and] create a distribution source halfway between two existing distribution sources in which we have inquiries for load growth." (Tr. at 149.)

30. NV Energy states that although the Apex Substation could accommodate a distribution transformer, NV Energy is only installing switching station equipment until a need to expand is evident. (Ex. 13 at 15; Tr. at 152.) NV Energy states that "this particular area has potential for significant development and the Companies have received proposals and inquiries for hundreds of megawatts of potential load growth." (*Id.*) NV Energy states that there is a high level of expected load for the Apex Industrial Park similar to the Henderson Project. (Ex. 14 at 4.)

31. Additionally, NV Energy provides that "Air Liquide is deeding land for the Apex Substation to the Companies at no cost." (Ex. 13 at 16.) NV Energy acknowledges that "if the utility installs the facility early, the Companies are at risk that the facilities are not determined to be used and useful until the ultimate build out occurs and, as a result, the cost could be disallowed." (Ex. 14 at 3.)

Commission Discussion and Findings

32. Pursuant to NAC 704.9385(3)(b), NV Energy is required to include, as part of its supply plan, a transmission plan that must include, without limitation, "[a] description of the transmission projects the utility is considering for expanding or upgrading the capabilities of its transmission system, the anticipated timing of those projects and the impact of the projects on the transmission capabilities of the existing and planned transmission system of the utility."

33. NAC 704.9494(1) requires that the Commission issue an Order approving the action plan of the utility as filed, or if the plan is not approved as filed, specifying those parts of the action plan that the Commission considers inadequate. NAC 704.9494(2) provides that "[a]pproval by the Commission of an action plan constitutes a finding that the programs and projects contained in that action plan, other than the energy supply plan, are prudent."

34. Pursuant to NAC 704.9494(4), "[a] utility may recover all costs that it prudently and reasonably incurs in carrying out an approved action plan in the appropriate separate rate proceeding."

35. In accordance with NAC 704.9385(3)(b), NV Energy provided the Commission with two electrically-feasible options capable of serving the load at Apex. The first electrically-feasible option is a 138-kV radial transmission line sourced from the Pecos Substation. The second electrically-feasible option is the dual-sourced Apex 230-kV Substation.

36. NV Energy explained that while the 138-kV radial transmission line originating at the Pecos Substation is electronically feasible, it is not actually feasible given permitting and time constraints. Specifically, NV Energy provided that it would be extremely unlikely, if not impossible, to construct the proposed 138-kV line because it would not be able to secure the necessary permits. Moreover, NV Energy indicated that it would not be able to construct the 138-kV line in time to provide service to Air Liquide by its in-service date in April of 2021. (*See* Tr. at 156.) Given the problems that NV Energy identified with the 138-kV radial line, the Commission agrees that it is not a viable transmission option.

37. NV Energy demonstrated that its other proposal, the Apex 230-kV Substation, is both electrically and actually feasible. No party presented evidence that it was not actually feasible, nor did any party identify permitting issues related to the proposed substation.

38. Staff argues that the Apex Substation would unjustly shift costs to ratepayers while benefitting Air Liquide. While the Commission takes Staff's concerns seriously, the Commission does not agree with Staff's proposal that Air Liquide should pay the full cost of constructing the Apex Substation. NV Energy proposed the Apex Substation as the best solution for serving all customers at the Apex Industrial Park, including but not limited to Air Liquide. Moreover, Air Liquide is deeding land for the Apex Substation to NV Energy at no cost. None of the Parties quantified the value of this land.

Given NV Energy's stated need for transmission, the potential for load growth in the Apex Industrial Park and surrounding areas, and the lack of other viable alternatives, the Commission finds that the Apex Substation is the most appropriate proposal to address transmission needs in the area. Accordingly, the Commission finds that construction of the Apex Substation is prudent. In approving NV Energy's request, the Commission notes that, consistent with NRS 704.110(13) and NAC 704.9494(4), NV Energy may recover all just and reasonable costs of the Apex Substation in an appropriate ratemaking proceeding.

C. Machacek Substation

NV Energy's Position

39. NV Energy requests that the Commission approve its preferred option of installing new 230-kV breakers in a ring bus formation at the Machacek 230-kV Substation. (Ex. 2 at 98.)

40. NV Energy claims that this installation is necessary to improve customer reliability and mitigate safety concerns related to operating aging equipment. (*Id.*) NV Energy explains that the installation will improve customer reliability because, with the current configuration, "a single contingency along the 115 mile Gonder to Frontier 230-kV line causes a

loss of Machacek 230-kV Substation and the entire Mt. Wheeler 20 MW load it serves." (*Id.*) NV Energy further explains that the proposed installation will mitigate safety concerns related to operating switches that personnel must manually operate with an extension bar. (*Id.*)

41. NV Energy states that SPPC is responsible for the required construction needed to add three 230-kV breakers in a ring bus formation to the Machacek Substation. (Ex. 2 at 98-99.) NV Energy states that the cost of adding three 230-kV breakers to the Machacek Substation would be approximately $6.2 million, including associated protection and communication buildings. (*Id.*)

BCP's Position

42. BCP recommends that the Commission deny NV Energy's request for the three 230-kV breaker addition at the Machacek Substation. (Ex. 10 at 2.)

43. BCP states that it reviewed the records of outages affecting Mt. Wheeler Power to evaluate the effectiveness of the proposed solution versus other known alternatives. (Ex. 10 at 3.)

44. BCP provides that it analyzed the outages to Mt. Wheeler Power beginning on January 1, 2014, and states that there were seven extended outages totaling 42 hours in aggregate. (Ex. 10 at 3-5 (referring to NV Energy's response to BCP DR 3-292).) BCP further states that there were two forced, extended outages reported by SPPC. (*Id.*) BCP states that the first forced, extended outage caused by a fire in July of 2016 resulted in a 75-minute outage and the second forced extended outage caused by non-scheduled maintenance on the motor-operated switches in March of 2019 resulted in a nine-hour outage. (Ex. 10 at 3-4.)

[2] See Attachment MDR-2 (SPPC's Response to BCP DR 3-29).

45. BCP provides that SPPC could spend $251,000 to replace the motor-operated switches and that such an expenditure would not require Commission approval because replacement of the motor-operated switches is maintenance. (*Id.* at 5.) BCP contends that the frequency and severity of the outages does not justify the price difference between the cost of $251,000 to replace the motor-operated switches with new motor-operated switches and the $6.2 million that it would cost to replace the motor-operated switches with NV Energy's preferred plan. (*Id.* at 4.) BCP states that the three-breaker ring bus would have prevented "only a single 75-minute forced outage" when compared to functional motor-operated switches. (*Id.* at 5.)

Staff's Position

46. Staff recommends that the Commission deny NV Energy's request to expend approximately $6.2 million to replace the motor-operated switches with three 230-kV breakers. (Ex. 11 at 2.)

47. Staff states that NV Energy maintained the Machacek Substation prior to purchasing it, and therefore, NV Energy should have known about any potential upkeep that the substation would require. (Ex. 11 at 6.) Staff further states that "[g]iven the asset was acquired in late 2012 and included in rates in 2013, we have just gotten beyond the payback period of the acquisition that [SPPC] outlined in 2012." (*Id.*) Staff states that it is troubled that ratepayers are going to have to invest an additional $6.2 million in the asset, which was purchased for $884,000 only six years ago. (*Id.*)

48. Staff further states that SPPC did not include a due diligence report in Docket No. 12-03016 and did not mention any concerns related to reliability or maintenance. (*Id.*) Staff states that if there were any concerns related to the reliability or maintenance of the switches, NV

Energy should have outlined those concerns for the Commission when seeking approval for the purchase of the asset. (*Id.*)

49. Staff supports BCP's view that the utility could replace the old motor-operated switches with new motor-operated switches, which would "solve the load interruptions associated with any planned maintenance on the 230-kV system while maintaining the same reliability that is currently being provided to Mt. Wheeler Power." (*Id.*)

50. Staff recommends that the Commission find that NV Energy has failed to provide adequate support for its request to spend approximately $6.2 million to add three 230-kV breakers at the existing Machacek Substation. (*Id.* at 7.)

NV Energy's Rebuttal

51. NV Energy states that the Machacek Substation violates NV Energy's most recent standards. (Tr. at 124; 145.) NV Energy explains that it would install at least a four-breaker ring bus if it were to build the Machacek Substation today. (Ex. 13 at 4.) NV Energy acknowledges that the motor-operated switches do not violate any "external standards or codes, FERC or otherwise." (*Id.*) However, NV Energy states that its policy documents detail how substations should be configured and that "[NV Energy's] standard is generally going to be a ring or a breaker-and-a-half configuration on the bulk electric system." (*Id.*)

52. NV Energy states that "[a]t 115 miles, the Mt. Wheeler load served out of the Machacek Substation is subject to the most transmission exposure in the Companies' entire transmission system." (Ex. 13 at 5.) NV Energy points out that the Machacek Substation is in a remote area and that dispatching personnel to that location affects response time. (Ex. 13 at 7.)

53. NV Energy states that Staff's and BCP's recommendations to install new motor-operated switches will not solve Mt. Wheeler's outage problems. (Ex. 13 at 6.) NV Energy

states that "if the Commission were inclined to approve Staff's and BCP's recommendations, the Companies would prefer not to move forward with the project until the circuit breakers could be approved because it would be a waste of time and resources to install motor-operated switches given that they do not resolve the problem presented to the Commission in this case." (*Id*; *See* Tr. at 128.) NV Energy states that it "would continue to pursue" the 230-kV breakers rather than install new motor-operated switches for the Machacek Substation. (Tr. at 128.)

54. NV Energy explains that new motor-operated switches might reduce the duration of outages, but they will not stop the outages from occurring; whereas, adding three 230-kV breakers would stop outages from occurring. (Ex. 13 at 10.) NV Energy further explains that the Machacek Substation is the only substation using 230-kV motor-operated switches for isolating major transmission lines. (Ex. 13 at 6.)

55. NV Energy states that the Commission could approve two-power-circuit breakers instead of the three-power-circuit configuration requested by NV Energy. (Ex. 13 at 7.) NV Energy states that this option would also allow the substation to be prepared for the "next interconnection." (Ex. 13 at 8.) NV Energy estimates that the two-power-circuit configuration would cost $4.25 million compared to the $6.25 million for the requested three-breaker configuration. (*Id.*)

56. NV Energy states that the two-breaker plan would make the Machacek Substation more reliable, but the substation would still require shutting down for maintenance. (*Id.*) NV Energy further states its preference that the Commission approve the two-breaker plan, rather than the alternative of new motor-operated switches suggested by BCP and Staff. (*Id.*) NV Energy argues that installing new motor-operated switches would "be a step in the wrong direction." (Ex. 13 at 8.) NV Energy states that a request for interconnection at the Machacek

Substation would result in the conversion of the Machacek Substation into a four-breaker ring and that this upgrade "would be funded by the Companies." (Ex. 13 at 9.)

57. NV Energy states that it has received complaints from the Chief Executive Officer of Mt. Wheeler Power regarding safety and reliability. (*Id.*) NV Energy further states that Mt. Wheeler has received complaints from its customers regarding outages. (*Id.*) NV Energy reports that Mt. Wheeler initially brought up these issues in 2015. (Ex. 13 at 10.)

58. NV Energy states that when it purchased the Machacek Substation there were no concerns about the motor-operated switches and no reason to identify them in a due diligence report because transmission planning and substation design was different in 2012. (Ex. 13 at 11.)

Commission Discussion and Findings

59. In the Joint Application, NV Energy proposes a $6.25 million three-circuit breaker ring bus solution to upgrade to the Machacek Substation. On rebuttal, NV Energy proposes a possible $4.25 million two-circuit breaker alternative. However, NV Energy does not provide any additional information regarding this alternative other than its lower price.

60. The Commission agrees with Staff's concern regarding the selection of the most expensive solution for the Machacek Substation, and the Commission is unable to dispel that concern with the limited information provided about NV Energy's two-circuit breaker proposal.

61. The Commission notes that the outage information provided in Attachment 3 of Exhibit 10, labeled as MDR-3, reflects that since June of 2015, only two momentary outages and two forced extended outages have occurred. Furthermore, it appears that properly-functioning motor-operated switches would have prevented one of the extended outages.

62. NV Energy claims that de-energization of the Machacek Substation requires opening the transmission path from the Gondor Substation. However, NV Energy does not