EB-2011-0140

IN THE MATTER OF sections 70 and 78 of the *Ontario Energy Board Act 1998*, S.O. 1998, c. 15 (Schedule B);

AND IN THE MATTER OF a Board-initiated proceeding to designate an electricity transmitter to undertake development work for a new electricity transmission line between Northeast and Northwest Ontario: the East-West Tie line.

INTERROGATORIES OF

RES CANADA TRANSMISSION LP

to

EWT L.P.

January 30, 2013

Interrogatory #1 Project Schedules

Reference:

a. AltaLink: Part B, Section 7

b. EWT: Part B, Exhibit 7

c. CNPI: Part B, Section 7

d. Iccon/TPT: Volume 1, Section 7

e. UCT: Section B, Section 7

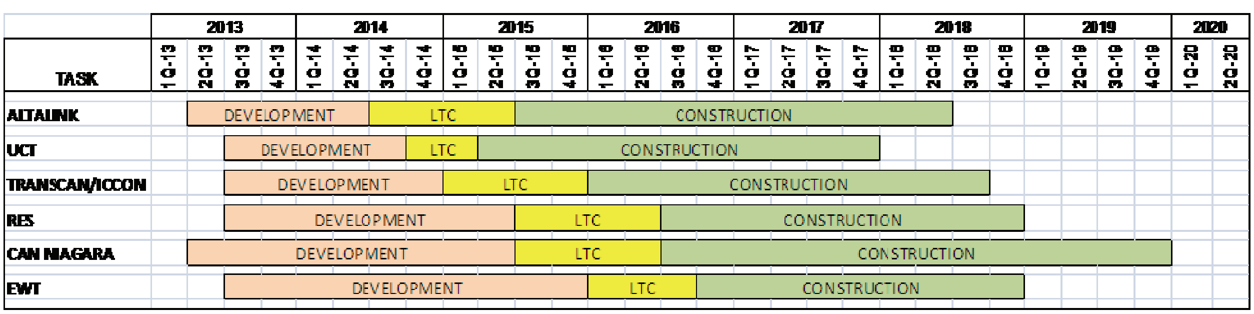
f. RES: Exhibit N

Preamble:

Each applicant has prepared development and construction cost estimates that are dependent, *inter alia,* upon underpinning project schedule assumptions. Some applicants have assumed aggressive project schedules. For example, both UCT and EWT assume that the leave to construct process – from application to decision – can be completed in less than one year. The generalized phase-by-phase project schedule of each applicant is shown in the table below.

The questions below are intended to test the reasonableness of the scheduling assumption and the sensitivity of development and construction cost estimates to changes in the project schedule that underpins each such estimate.

Table 1: Project Schedules



Questions:

a. What evidence can EWT offer that a nine month leave-to-construct phase – from application to decision – is reasonable and achievable?

b. Provide an indication of the time required to obtain pre-construction environmental permits, following Ministry of Environment approval of EWT's Environmental Assessment.

c. Indicate whether and, if so, where the time to apply for and obtain pre-construction permits is accounted for in EWT's project schedule.

Interrogatory #2 Mining and Timber Rights

Reference:

a. AltaLink: no reference to mining or timber rights in its Land Plan (Part B, Section 9) or Costs (Part B, Section 8)

b. EWT: Part B, Exhibit 9

c. CNPI: Part B, Section 9, page 141 of 160

d. Iccon/TPT: no reference to mining or timber rights in its Land Plan (Volume 1, Section 9) or Costs (Volume 1, Section 8)

e. UCT: Section B, Section 9.2, Figure 29, page 134

f. RES: Exhibit B-1-1, page 12 of 35, lines 17-18, and page 13 of 35, lines 1-5; Exhibit B-3-2; Exhibit E-4-1, page 1 of 11, lines 5-8 and page 4 of 11, lines 15-17; Exhibit K-4-2, pages 12, 14, and 15, and Appendix A, D and E; Exhibit K-5-1, page 1 of 2, lines 17-24 and page 2 of 2, lines 25-47; Exhibit K-6-1; Exhibit L-1-1, page 4 of 4; Exhibit L-3-1, page 2.30 and Appendix C; Exhibit L-4-1, pages 11-13; Exhibit N-2-3, page 2 of 3; Exhibit N-3-3, page 2 of 7; Exhibit P-5-1, page 11 of 12

Preamble:

Although most of the applications refer to mining claims and timber rights on Crown lands as routing issues that will need to be addressed, most are silent as to <u>how</u> such issues will be addressed and at <u>what cost</u>. The cost of obtaining required consents from parties with prior mining and timber rights on Crown lands that comprise part of a proposed transmission right-of-way can be material and significant. Obtaining such consents and/or otherwise dealing with such prior rights and entitlements can take a great deal of time.

Questions:

a. Indicate where, in its application, EWT provides a list of registered mining claims on Crown lands along EWT's proposed transmission route(s).

b. Indicate where, in its application, EWT describes its plans to accommodate parties with registered mining claims and/or timber rights on Crown Lands that comprise part of its proposed transmission right-of-way(s).

c. Indicate where, in its application, EWT has estimated the cost of obtaining the consent and other permissions that would be required from parties who hold registered mining claims and/or timber rights on Crown Lands that comprise part of its proposed transmission right-of-way(s)?

d. Are the costs referred to in “c” above, included in:

(i) EWT’s development cost estimate; and/or

(ii) EWT’s construction cost estimate?

e. Indicate in which project phase – development, leave-to-construct or construction – EWT intends to negotiate consent agreements with parties who hold registered mining claims and/or timber rights on Crown lands that comprise part of its proposed transmission right-of-way(s).

Interrogatory #3 Land and Contingency Cost Exclusions

Reference(s):

a. Part B, Exhibit 6, Appendix 6A, Figure 1 and Figure 2

b. Part B, Exhibit 6, Appendix 6D, Figure 1 and Figure 2

c. Part B, Exhibit 8, page 4 of 31, lines 15-16

d. Part B, Exhibit 8, Table 8.1, pages 4-5 of 31

e. Part B, Exhibit 8, page 5 of 31, lines 14-15

f. Part B, Exhibit 8, page 15 of 31 risk tabulation

g. Part B, Exhibit 8, page 21 of 31, lines 5-6

h. Part B, Exhibit 8, Table 8.2, pages 22-23 of 31

i. Part B, Exhibit 8, page 23 of 31, line 5

Preamble:

EWT indicates that it has included $1.0 million in its development cost budget for "transaction costs for acquiring land rights for the Project excluding expropriation and the cost of land rights themselves". An estimate of these excluded land costs is not included in its construction budget. In 2010, EWT's affiliate, Hydro One, estimated "real estate" costs for the Project of $15,127,000, in its construction budget[1].

EWT has included an estimate of contingency costs of 20 percent in its OM&A budget and stated that "contingency is inherent in any development project".

Questions:

a. The total amount budgeted for land costs in EWT's development and construction cost estimates is $1.0 million:

(i) is $1.0M the total amount that EWT expects to expend for land rights for the project; and

[1] Hydro One, Project Definition Report, Study Estimates for Options, East-West Tie Expansion, AR 18379, June 4, 2010, page 38 of 43.

(ii) if the response to (i) is "no," what is the total amount EWT expects to expend on land rights for the project in each of the development and construction phases?

b. The Power Engineers' study for the reference design (reference "a") states that "the cost of ROW purchase and temporary land needs for construction are not included in this estimate". Indicate where, in its application, EWT provides an estimate of the right of way costs for the reference design.

c. There is no estimate of right-of-way costs in the Power Engineers' study for the proposed alternate CRS design. Indicate where, in its application, EWT provides estimates of the right-of-way costs for the alternate CRS design.

d. Although EWT has stated that "contingency is inherent in any development project," it has not provided an estimate of contingency costs in either its development or its construction budget. Provide estimates of the contingency costs that would be added to EWT's development budget and to its construction budget.

e. To what extent will existing land rights that are currently held by one of EWT's parent companies (eg., Hydro One) be utilized or shared by EWT?

f. If land rights that are held by Hydro One are utilized or shared by EWT, will the existing agreements that govern Hydro One's existing rights (for example, land use permits issued by the Crown), need to be renegotiated or changed?

g. If the response to "e" is "yes," will EWT reimburse Hydro One in respect of any associated incremental costs? Is this cost included in EWT's application and, if so, where?

Interrogatory #4 Costs of Alternate Routes

Reference(s):

a. Part B, Exhibit 9, pages 20-36 of 37

b. Part B, Exhibit 9, page 21 of 37, Figure 9.1

c. Part B, Exhibit 9, page 27 of 37, Figure 9.2

d. Part B, Exhibit 9, page 30 of 37, Figure 9.3

Preamble:

In its application, EWT considers the reference route and also identifies three alternative route options. The application specifies development and construction cost estimates for the reference route only.

Questions:

a. Indicate where, in EWT's application, the length of the East-West Tie line under each of the three alternative route options is specified.

b. Confirm (with a "yes" or "no" response) if EWT's project schedule, land acquisition plan, environmental assessment plan and permitting plan, as these are set out in its application, apply equally to the three alternative route options?

c. Confirm (with a "yes" or "no" response) if the estimates of development and construction costs, as set out in its application, apply equally to each of the three alternative route options.

Interrogatory #5 Pre-Designation Costs

Reference(s):

a. Part B, Exhibit 8, page 2 of 31, lines 1-6

b. Part B, Exhibit 8, pages 3 to 7 of 31

Preamble:

Pre-designation costs (from February 2, 2012) are included in the Board's definition of development phase costs. EWT indicates that it incurred $1.545M prior to submitting its application and will incur additional costs, during the designation proceedings.

Questions:

a. Is the full $1.545M included in EWT's development cost estimate of $22.1 million?

b. If the response is "no," explain the basis of the response.

Interrogatory #6 Design Deviations, Variations, and Alternatives

Reference(s):

a. Application, page 4 of 6, lines 3-8

b. Summary, page 9 of 14, lines 10-28; page 10 of 14, lines 1-27; page 11 of 14, lines 1-5

c. Part B, Exhibit 6, Section 6.0, page 1 of 21, lines 18-19; page 2 of 21, lines 1-7

d. Part B, Exhibit 6, Section 6.1, page 3 of 21, lines 1-8

e. Part B, Exhibit 6, Section 6.2, page 6 of 21, lines 10-11

f. Part B, Exhibit 6, Section 6.4, page 8 of 21, lines 1-26; page 9 of 21, lines 1-37; page 10 of 21, lines 1-18; page 14 of 21, lines 7-25; page 15 of 21, lines 1-26; page 16 of 21, lines 1-4; page 18 of 21, lines 1-23; page 19 of 21, lines 1-13; page 17 of 21, Table 6.1

g. Part B, Exhibit 6, Appendix 6F

Preamble:

EWT has proposed design “deviations and variations” to the Reference Option as well as an alternate “single circuit design with CRS”. Moreover, EWT proposes not connecting at the Marathon TS as an option that may be considered in the future.

Section 6.4 of the Board’s Filing Requirements (Phase 1 Decision and Order dated July 12, 2012) states that: “[W]here the Plan is not based on the Reference Option the applicant must file …[a] Feasibility Study performed by the IESO”.

Questions:

a. In reference “e”, EWT states that it “plans to evaluate whether [. . .] there is a need to interconnect the new line at Marathon..”:

   (i) what is the basis for proposing this option; and

   (ii) has the IESO considered the reliability and system performance of this option?

b. Has the IESO prepared feasibility studies for the design variations and deviations proposed by EWT in reference “c”, including EWT’s proposed “single circuit design with CRS”?

c. In reference “f”, EWT states as follows: “cost savings of approximately $116 million may be achievable by adopting a single circuit solution with CRS structures as used in ALT B compared to the Reference-Based Design, or approximately $70 million compared to the optimized double circuit design of Ref B.” In the absence of an IESO feasibility study confirming the reliability and performance of this design, where in its application does EWT present the factual underpinning of these estimates?

Interrogatory #7 Schedule Compression

Reference(s):

a. Application, page 4 of 6, lines 12-18

b. Summary, page 11 of 14, lines 7-21; page 12 of 14, lines 1-31

c. Part B, Exhibit 7, Section 7.2, page 5 of 49, lines 1-6; page 8 of 49, lines 13-32; page 44 of 49, lines 16-22

d. Part B, Exhibit 7, Section 7.5.2.1, page 45 of 49, lines 8-12; page 46 of 49, lines 1-28; page 47 of 49, lines 1-27; page 48 of 49, lines 1-24; page 45 of 49, Figure 7.3

Preamble:

EWT has proposed a 36 month development schedule and indicates that it could be shortened to 23 months. It cautions however, that it "is inappropriate at this stage to assume a more aggressive environmental assessment timeline…"

Questions:

a. Provide a narrative that discusses the issues and concerns associated with an expedited development schedule, having regard, *inter alia*, to environmental assessment timelines.

Interrogatory #8 Bruce-Milton Project Experience

Reference(s):

a. Part A, Exhibit 2, Page 10 of 28, lines 17-19

b. Part B, Exhibit 8, Section 8.10.1, page 28 of 31, lines 4-11

Preamble:

EWT cites Hydro One's experience on the Bruce to Milton project as an example of one of its partners completing a transmission project under budget and on time.

Hydro One's 2007 leave to construct application estimated costs for the Bruce to Milton project at $635M and projected a December 2011 in-service date. Ultimately, the project went into service in June 2012 at a total cost of $709 M.

Questions:

a. Explain how EWT's statement that the Bruce-Milton project came in under budget by $44M can be reconciled with the fact that the final cost of this project was at least $74M more than the original $635M estimate stipulated in Hydro One's 2007 leave to construct application.[1]

b. Explain how EWT's statement that the Bruce-Milton project was put into service "seven months ahead of schedule in 2012" (reference "a") can be reconciled with the fact that the project did not go into service until June 2012, six months after the scheduled in-service date.[2]

[1] EB-2007-0050, Exhibit B, Tab 4, Schedule 2, page 1 of 5, lines 1-8.
[2] EB-2007-0050, Exhibit B, Tab 5, Schedule 2, page 1 of 1.

Interrogatory #9 Disparity in Affiliates' Cost Estimates

Reference(s):

a. Part B, Exhibit 7

b. Part B, Exhibit 8

Preamble:

In 2010, Hydro One estimated the cost of the line portions of the East-West Tie line at $636 million (reference design) and another $43.7 million for development, for a total of $679.8 million[1]. It also projected a seven year schedule to achieve a December 2016 in-service date.

In its application, EWT is proposing to construct the East-West Tie line for approximately $427 million (within a range of $340 million to $510 million), at a development cost of $23.6 million (inclusive of $1.545 million in pre-designation costs) and for a total project cost of $450.6 million. EWT also proposes a 5.5 year development and construction schedule to achieve an in-service date of December 2018.

Given the relationship between EWT and Hydro One and the fact that EWT has relied on the credentials of Hydro One and its familiarity with the project to make the case that EWT has the requisite credentials to be the designated transmitter, the question of how these cost and schedule disparities can be reconciled is a reasonable one.

Questions:

a. Reconcile Hydro One's 2010 estimate of project costs ($679.8 million) with EWT's 2013 estimates of project costs ($450.6 million).

b. Reconcile Hydro One's 2010 project schedule (7 years) with EWT's project schedule for the East-West Tie line (5.5 years).

[1] Hydro One Project Definition Report, AR 18379, Study Estimates for Options, East-West Tie Expansion, June 4, 2010, 43 pages

Interrogatory #10 Viability of Guyed Structures

Reference(s):

a. Summary, Page 10 of 14, lines 9-27; Page 11 of 14, lines 1-5; Page 13 of 14, lines 1-4

b. Part B, Exhibit 6, Page 2 of 21, lines 6-7; Page 14 of 21, lines 7-25; Page 15 of 21, lines 1-26; Page 16 of 21, lines 1-4; Page 17 of 21, lines 1-8; Page 18 of 21, lines 1-23; Page 19 of 21, lines 1-26; Page 20 of 21, lines 1-2; Page 17 of 21, Table 6.1;

c. Part B, Exhibit 6, Appendix 6D

d. Part B, Exhibit 6, Appendix 6E

e. Part B, Exhibit 6, Appendix 6F

f. Part B, Exhibit 7, Page 9 of 49, lines 10-16; Page 27 of 49, lines 26-27; Page 28 of 49, line 1; Page 49 of 49, lines 2-7

g. Part B, Exhibit 8, page 21 of 31, lines 15-18

h. Attachment 1: U.S. Bureau of Land Management Memorandum

i. Attachment 2: Wisconsin Department of Natural Resources, 2003-2004 Snowmobile Enforcement and Safety Report, page 14

j. Attachment 3: CBC article

k. Attachment 4: Meadow Lake Progress article

l. Attachment 5: NV Energy *2012 Integrated Resource Plan*, Volume 16, filed with the Public Utilities Commission of Nevada on June 16, 2012, pages 10 to 11 and 90 to 94

Preamble:

EWT has proposed the use of a guyed cross-rope suspension (“CRS”) transmission structure to minimize construction costs, stating that “[e]very study conducted by POWER over the last 20 years that compares structure types for HV or EHV transmission line application points to significant capital cost savings when a guyed tower type is compared to a self-supported type.”

In North America, questions have been raised regarding the suitability of guyed structures, such as those proposed by EWT. There are numerous reasons why: concerns about the durability of structures in extreme climates;

difficulty managing vegetation around guyed structures; the need for wider rights-of-way; higher annual operation and maintenance costs; risk to bat and avian species; tower failure and in-line multiple tower cascades as a result of the loss of guy wires; accidental or intentional guy wire damage; and risk to recreational users of transmission right-of-way (e.g., snowmobilers).

EWT's application offers little information regarding the suitability of guyed towers in northern Ontario, where extreme climate and corrosive soil conditions prevail. Nor does it address the other potential problems with guyed towers, listed above.

Questions:

a. Reference "h" (Attachment 1) comments on the use of guyed structures on public lands in the United States. The memorandum links guyed structures to increased avian mortality. Accordingly, with respect to transmission facilities located on United States public land "[t]he use of self-supported structures (i.e. structures that do not require guy wires for support and stability) are preferred wherever feasible".

   (i) Indicate where, in its application, EWT addresses the risk to avian and bat species posed by guyed structures.

   (ii) Confirm whether the cost of guyed towers included in EWT's cost estimates is net the cost of mitigating the adverse effects of guyed structures on bat and avian species.

   (iii) Confirm whether the cost of guyed towers included in EWT's cost estimates is net of the cost of securing permits required under the *Endangered Species Act, 2007*, vis-à-vis the increased risk to certain avian and bat species.

b. There are many cases documenting injuries and fatalities that have resulted from high-speed collisions with transmission guy wires, particularly in the case of recreational snowmobilers (see Attachments 2, 3, and 4). It is not uncommon for designated recreational snowmobile trails, in northern Ontario, to follow transmission rights-of-way. In light of this, explain why EWT is proposing to use guyed structures.

c. The Executive Summary of the Power Engineers Report Assessment of the Use of CRS Structures on HV/EHV Transmission Lines (reference "c") states that "[E]very study conducted over the last 20 years that compares structure types for HV or EHV transmission line application points to significant capital cost savings when a guyed tower type is compared to a self-supported type". Confirm:

(i) how many studies reached this conclusion; and

(ii) how many such studies relate to projects that were actually constructed using guyed structures?

d. Notwithstanding the statement that Power Engineers has recommended the use of guyed structures in "multiple reports" over the last 20 years (reference "c"), only two North American installations of guyed CRS structures are identified. The most recent of these was installed in the 1980s. If guyed structures offer significant capital cost savings, compared to self-supporting structures, explain why guyed CRS installations are not more prevalent in North America.

e. There are documented cases, in North America, of guyed structures failing under extreme climatic conditions, for example, in high winds (see Attachment 5). Given the harsh climate in northern Ontario:

(i) indicate where, in its application, EWT describes the measures it intends to take in order to minimize the risk of tower failure; and

(ii) indicate whether EWT has included, in its construction cost and/or operations and maintenance estimates, a contingency for tower failure.

f. In respect of the CRS guy anchor foundations described in reference "c", indicate where, in its application, EWT addresses the mitigation measures required to reduce the expected corrosion of guy anchors.

g. Indicate where, in its application, EWT addresses the inspection and maintenance procedures required to ensure the long-term performance of the guys supporting the towers described in references "c" and "d"?

h. Indicate where, in its application, EWT discusses the sufficiency of its annual operation and maintenance budget, in relation to the additional inspection and maintenance typically required for guyed structures.

i. Where in the proposal does EWT's annual O&M budget address the additional operation and maintenance that would be required in respect of guyed structures?

Interrogatory #11 Future Expansion to 500kV

Reference(s):

a. Part B, Exhibit 6, Section 6.5.3

b. Part B, Exhibit 6, Appendix 6D

Preamble:

The Power Engineers CRS Report that is included in reference “b” states that the bundled 795 ACSR conductor, as proposed in EWT’s single circuit option, can set the stage for adding additional conductors for a future 4-bundle 500kV circuit. There is, however, minimal discussion as to what other components or modifications, beyond additional conductors, would be required to facilitate a future conversion to 500kV. These could include, for example, requirements for increased structure heights and widths, increased insulation and increased conductor phase spacing. EWT’s application does not indicate whether and when these additional components and modifications will be incorporated into its proposed design nor what the associated cost would be. In addition, it has not cited any plans or studies that indicate that 500 kV is being considered at any point in the future, for the area.

Questions:

a. Describe what other components and/or modifications to the proposed single circuit design, other than the bundled 795 ACSR conductor, (e.g. structure, insulator, and spacing modifications, etc.) would be required in order to accommodate a future 4-bundle 500kV circuit.

b. Indicate whether the components and/or modifications identified in response to question “a,” above, would be installed when the single-circuit design is first constructed or incorporated at a later date, when additional conductors are added to accommodate a 500kV circuit.

c. If required components and/or modifications would be installed at a later date, describe the expected construction timeline in respect of these modifications, having regard to the need to take the new single circuit line out of service. Comment on the length of the outage required to modify each transmission structure, install new conductors and upgrade station equipment.

d. Are the costs associated with the conversion of EWT’s single circuit design to a 500kV circuit included in the cost estimates set out in the application? If the response is “no”, explain why not.

e. Where, in its application, does EWT identify any definitive, announced plans for adding 500kV transmission in the project area, including the need and timing for such an addition.

Interrogatory #12 First Nations and Métis Participation

Reference(s):

a. Application, page 3 of 6, lines 7-13

b. Summary, page 2 of 14, lines 1-7; page 6 of 14, lines 8-30; page 7 of 14, lines 16-21; page 7 of 14, lines 1-26

c. Part A, Exhibit 3, Section 3.1, page 2 of 11, lines 1-12; page 3 of 11, lines 1-24; page 4 of 11, lines 1-25; page 5 of 11, lines 1-34; page 6 of 11, lines 1-18; page 7 of 11, lines 1-21

Preamble:

EWT has made arrangements with some First Nations (through Bamkushwada LP) to participate as a partner in the East-West Tie line, in the event that EWT becomes the designated transmitter. These arrangements were announced by EWT on July 11, 2011.

It would appear that some First Nations and Métis communities have been excluded from participating in Bamkushwada LP. Moreover, the "Participating First Nations" have been granted preferential rights to provide goods and services to the project.

It would be helpful to understand more about the Bamkushwada arrangements, including whether they preclude another applicant from negotiating a comparable or better arrangement with a larger group of potentially affected First Nations and Métis communities (as identified by the Minister of Energy's letter of May 31, 2011).

Questions:

a. How and why was it determined to include only six First Nations in the Bamkushwada group (defined by EWT as "Participating First Nations")?

b. Were any of the 12 First Nations and Métis communities that are listed in the Minister of Energy's May 31, 2011 letter to the OEB and who were not included as part of Bamkushwada LP (defined by EWT as "Non-Participating First Nations and Métis") offered an opportunity to participate in the partnership and, if so, on what terms?

c. Under its arrangement with EWT, will Bamkushwada LP bear an equal share, relative to the other two EWT partners, of the costs of pre-designation, development and construction activities, in the event that EWT is designated?

d. Under its arrangement with EWT, will Bamkushwada LP bear an equal share of project risk during all phases of the project, relative to the other two EWT partners?

e. Does EWT's participation arrangement with Bamkushwada LP constrain or preclude the Participating First Nations from considering alternate participation plans proposed by the designated transmitter, if that transmitter is not EWT?

f. What is the basis for the following statement in reference "b", (page 6 of 14, lines 25-29): "For transmitters that have not made similar participation arrangements, there is a real risk they will not be able to do so, or that they will only be able to do so if they first take a similar amount of time to develop the necessary relationships, and then only if their visit on for the Project aligns with that of the Participating First Nations"?

g. Does EWT agree that comparable or better arrangements (from the perspective of First Nation and Métis communities, other affected stakeholders and/or Ontario ratepayers) could be entered into with a designated transmitter, other than EWT?

h. How will providing preferential rights to the Participating First Nations affect EWT's ability to conduct successful consultation with Non-Participating First Nations and Métis communities?

i. Since EWT intends to give priority (with respect to employment, training, and commercial opportunities) to Participating First Nation community members and to businesses owned or controlled by a Participating First Nation or its members (see Summary, Page 7 of 14, lines 16-21), to what extent can Non-Participating First Nation and Métis communities, who are impacted by the project:

  (i) provide goods and services to the Project; and

  (ii) participate in the project?

Interrogatory #13 Proposed Rate Methodology

Reference(s):

a. Part B, Exhibit 8, Section 8.6, page 18 of 31

Preamble:

In Reference "a", EWT states as follows:

"[EWT] believes that a traditional cost-of-service methodology is the most reasonable and transparent approach for a project at this 'greenfield' stage. Without project history, an incentive-based scheme may simply push project costs to be claimed at a later stage. Once the Project is operating, however, an incentive regime could be more fully considered. EWT also notes that the $6.87 billion of new transmission projects being built as part of Texas' *Competitive Renewable Energy Zone* continue to be subject to conventional cost-of-service rate making by the Public Utility Commission of Texas even though the transmitters were selected through a highly innovative new process that shares many of the features of the Board's own new designation process."

Questions:

a. In EWT's view, does a traditional cost-of-service approach, that passes all cost overages deemed to be prudent to ratepayers, provide superior risk mitigation from the perspective of ratepayers, relative to an incentive-based methodology that allocates (i.e., shares) cost overages and underages between ratepayers and the utility? Explain the reasons that underpin your response.

b. Assuming that the East-West Tie line is placed into service on December 31 of the year preceding the year in which an initial cost-of-service application for the East-West Tie line is brought (the "**Preceding Year**"), calculate the incremental year 1 revenue requirement associated with a $50M capital cost overage (relative to EWT's estimate of total project cost), under the traditional cost-of-service approach proposed by EWT.

c. Assuming that the project is placed into service on December 31 of the Preceding Year, calculate the incremental year 1 revenue requirement associated with a $50M cost overage (relative to EWT's estimate of total project cost), under the traditional cost-of-service approach proposed by EWT but where the $50M cost overage earns a return on equity that is equal to the Board-prescribed (2013) rate for long-term debt.

Interrogatory #14 Partner Loans to EWT

Reference(s):

a. Part A, Exhibit 5, page 3 of 17

Preamble:

Reference "a" states that EWT "will finance the development of the Project through partner loans from Hydro One and GLPT-EWT (through Brookfield Infrastructure) to EWT. The partner loans are debt to the partnership and have no impact on the equity of the partnership which will remain equally shared by Hydro One, BLP, and GLPT-EWT during development. While third party funding may be arranged during the development stage, it is not expected to be required."

Hydro One is a crown corporation whose sole shareholder is the Ontario Government.

Questions:

a. Confirm that if Hydro One grants a partner loan to EWT, the Ontario Government will, in effect, be subsidizing an equity investor's participation in the project.

Interrogatory #15 Route Access and Water Crossings

Reference(s):

a. Exhibit 6, Appendix 6A, page 2; page 7; Figure 1; Figure 2

Preamble:

The East-West Tie line will be located in a relatively remote part of the province, characterized by limited existing road access and several hundred water crossings.

EWT does not quantify the cost of constructing the multiple water crossings that will be required. Moreover, in reference “a”, Appendix 6A at page 7, new access road construction is assumed to be required for “40% of the line length at a rate of $25,000/km”. However, in reference “a”, Appendix 6A, Figures 1 and 2, access road construction is assumed to be $9,000/km.

Questions:

a. Reconcile the two estimates of the cost of constructing new access roads: $25,000/km (Appendix 6A, p. 7) vs. $9,000/km (Appendix 6A, Figures 1 & 2).

b. Indicate where, in its application, EWT describes its plan for crossing watercourses and wetlands and explain how this plan is reflected in EWT’s cost estimates.

c. Indicate what level of costs for crossing wetlands and watercourses is included:

   (i) in EWT’s development cost estimate; and

   (ii) in EWT’s construction cost estimate.

d. Has EWT performed a quantitative access road inventory, including an assessment of the level of improvement effort per road type and the associated costs: “yes” or “no”.

e. Describe what consideration, if any, were given to helicopter construction and how these considerations were incorporated into EWT’s:

   (i) development cost estimate; and

   (ii) construction cost estimate.

   having regard to the limitations to traditional ground access posed by the topography and extensive wetlands that characterize northern Ontario.

ATTACHMENT 1

United States Department of the Interior
BUREAU OF LAND MANAGEMENT

California State Office
2800 Cottage Way, Suite W1623
Sacramento, CA 95825
www.blm.gov/ca

December 4, 2012

In Reply Refer To:
6840, 6510 (CA-930) P

EMS TRANSMISSION: 12/4/12
Instruction Memorandum **No. CA-2013-004**
Expires: 9/30/2014

To: All BLM CA District and Field Managers

From: State Director

Subject: Revision of Guy Wire and Lighting Requirements for Tall Structures

This Instruction Memorandum replaces IM CA-2011-003. This Instruction Memorandum provides requirements for all structures requiring guy wires and lights (e.g., meteorological towers, cell phone towers) on BLM administered lands for which the approval of said structures is done with a Categorical Exclusion. This Instruction Memorandum applies to all new structures. This Instruction Memorandum applies to existing structures only when they are modified, retrofitted, or reinstalled. In order to use a Categorical Exclusion (CX) under NEPA, a project must not adversely affect species of special concern (e.g., species protected under the Endangered Species Act or Bald and Golden Eagle Protection Act). Tall, thin structures, such as meteorological towers, pose a collision risk to wildlife species. These potential impacts are subject to analysis under the National Environmental Policy Act (NEPA) prior to our granting of a Right-of-Way. The implementation of these measures reduces the collision risk for avian species sufficiently that a CX may be used. If the guidelines below are not implemented, a full NEPA analysis (EA or EIS) must be conducted.

A wide variety of bird species have been documented to collide with guy wires and power lines. It is generally believed that birds collide with lines because the lines are invisible to the birds or because the lines are not seen until it is too late for birds to avoid it. Large, less maneuverable birds are especially vulnerable to collisions with guy wires, which are relatively thin and difficult to see from a distance. Poor weather conditions, such as fog, rain or snow, as well as darkness, make the lines even more difficult to see. The following measures increase the visibility of such structures.

1. The use of self-supported structures (i.e., structures that do not require guy wires for support and stability) are preferred whenever feasible. The structure should be painted so that it stands out from the surrounding environment to provide optimum visibility for birds. However, if the use of self-supported structures is not feasible, non-self-support structures with guy wires may be used provided that the wires are marked using the following protocols.

2. Each and every guy wire (not just external wires) should be clearly marked for the length of the wire. Starting at the top of the guy wire, the first marker must be placed within the first 15 feet of length. The last marker can be no more than 15 feet from the ground at the end of the guy wire. Markers should be of a color that does not blend with the wire. Choice of marker and spacing of the markers along the guy

wire must use one of the following options.

a. Spiral flight diverters (i.e., open-ended BIRD FLIGHT™ diverter or closed SWAN FLIGHT™ diverter or equivalent technology) spaced at intervals no greater than 15 feet apart.

b. "FireFly™" 'flapper' secured with a dropped forged galvanized cable (u-bolt) clamp or equivalent technology, spaced at intervals no greater than 30 feet apart.

c. In an alternating pattern, FireFly™ (or equivalent technology), and spiral flight diverters (e.g., open-ended BIRD FLIGHT™ diverter or closed SWAN FLIGHT™ diverter or equivalent technology) at spacing intervals of 15 feet apart.

Applicants must comply with manufacturer recommendations when using the methods outlined above. If an applicant proposes an alternative method of marking guy wires, that method must be approved by the BLM, and the applicant must conduct regular monitoring for bird fatalities (including scavenger and detectability correction factor studies) for all structures with guy wires.

3. Avoid placing lines within wetlands, over canyons, or within important avian movement corridors (i.e., between foraging and nesting sites).

4. Lights are sometimes used to mark guy wires and power lines. Because lights can both attract and confuse migrating birds, use lights only if lighting is needed for aviation safety. Unless otherwise requested by the Federal Aviation Administration, use only the minimum number of strobed, strobe-like, or blinking incandescent lights with a minimum intensity, maximum "off-phased" duel strobe lights. No steady burning lights (e.g., L-810) should be used. All lights should illuminate simultaneously.

5. If fatalities are observed, they must be reported immediately to the managing Field Office and the State Wildlife Specialist.

Questions on implementing measures for guy wires and lighting to reduce avian collisions may be directed to Amy Fesnock at (916) 978-4646.

Signed by: Karen L. Barnette Acting State Director	Authenticated by: Richard A. Erickson Records Management

ATTACHMENT 2

Wisconsin
Department of Natural Resources
2003-2004 Snowmobile
Enforcement & Safety Report

WISCONSIN
DEPT. OF NATURAL RESOURCES

Produced by the Bureau of Law Enforcement, Recreation Enforcement and Education Section

PUB-LE-203 2004

WISCONSIN CONSERVATION WARDEN

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2003-2004 Snowmobile Program Report
Summary

The 2003-2004 Snowmobile Program Report was compiled from the 25 fatal investigations and other data collected during the fiscal year 2003-2004 (a fiscal year runs from July 1 – June 30).

Conservation Wardens investigate all fatal snowmobile incidents and as such, Wisconsin law requires that a conservation warden or law enforcement officer be notified immediately of any snowmobile incident that results in an injury requiring medical treatment by a physician. In addition, the operator(s) involved in these reportable incidents must file a written report with the Department of Natural Resources within 10 days, in so far as they are capable of doing so.

FATAL INCIDENT CAUSES

The primary type of crash causing the victim's death continues to be striking a fixed object such as trees or ice/rock. The secondary type of crash leading to the victim's death this reporting period was collision with another snowmobile. The leading contributing factors were alcohol and excessive speed.

There were 12 (9 the previous year) fatal crashes that investigators directly identified speed as a contributing factor to the death of the operator/passenger. Of the 12 speed related fatals, 9 of those that died had consumed alcohol or 75% (77% the previous year) of the speed related victims.

Alcohol was identified as another major contributing factor. The 2003-04 laws expressly stated a person is under the influence of alcohol once their blood alcohol level reaches 0.08; however, for the purposes of this report, any alcohol level identified in the coroner's report (by percent) is considered to be a contributing factor.

Seventy-two percent (18 of the victims) of the known toxicology reports performed show alcohol was consumed by the victim. Toxicology examinations were not performed on six victims; one victim had no alcohol present. A review of the alcohol involved fatals show that no victims had less than 0.03 alcohol levels. Twenty percent of the victims that consumed alcohol showed levels less than .08%. Twenty percent of the victims that consumed alcohol had levels from 0.10 to 0.199%. The other thirty-six percent of the alcohol related victims were reported at 0.20 or above, with one victim result at 0.284.

WHO WAS INVOLVED

Twenty-four of the 25 victims were male. Victim ages ranged from 15-60 years, with the average age 35.2 years old; last season's average age was 35.3 years. The largest percentage of victims was age 30-39 years. The second largest age group was age 40-49 years at 24%. Three children under 16 were killed this reporting period. Of the 25 fatal incidents, 19 of the victims were Wisconsin residents while 4 were from Illinois and 2 from Minnesota. The majority of the victims (22) had not received Wisconsin Snowmobile Safety Training. Of the 25 victims, 18 were known to have been wearing a helmet, 3 were not wearing a helmet.

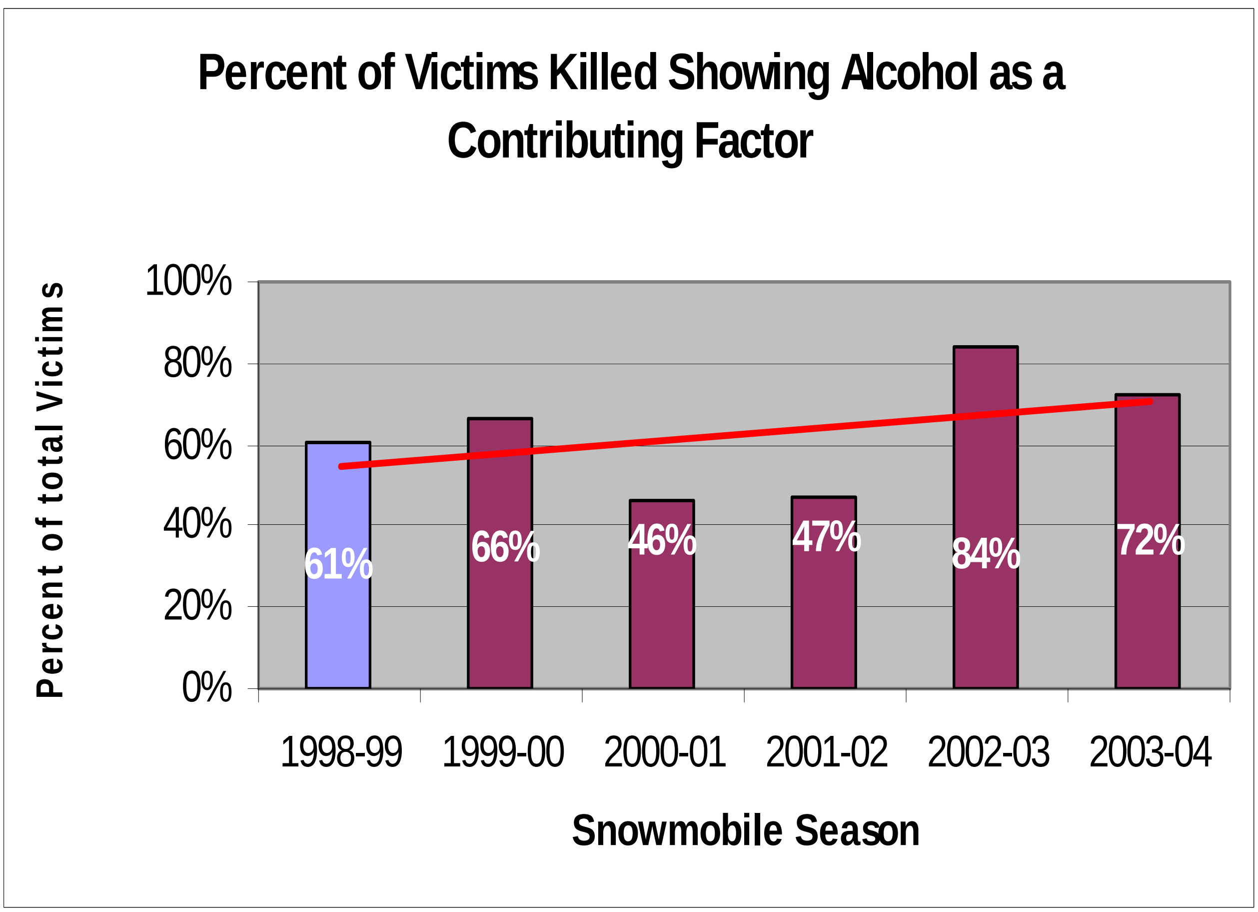
WHEN DO THE FATAL INCIDENTS OCCUR

A correlation was observed by reviewing fatality statistics for the past ten years. Inferences can be drawn as to the time of day and the day of the week that fatal incidents are most likely to occur. Statistics show the majority of the snowmobilers were fatally injured on Friday, Saturday or Sunday. Saturdays show a higher number of victims over any other day. The time of day/night that snowmobilers are most likely to be involved in a deadly incident is between the hours of 7:00 pm - 3:00 am.

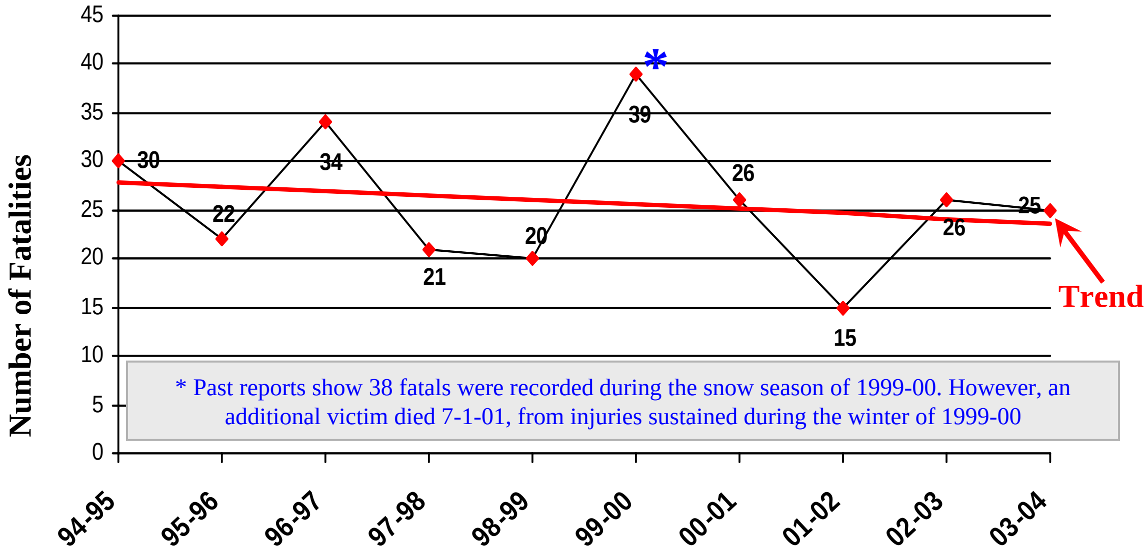
FACTORS TO BE CONSIDERED

The statewide 2003-2004 snowmobile season never really acquired traditional snowfall depths, it began late and was essentially the same as the previous year. Open water remained a hazard throughout the season. Open water was a contributing factor for six of the fatal incidents. Many trails in the southern portion of the state did not open the entire season and trails in the north were plagued with poor snow depths resulting in less than prime conditions.

Wisconsin has been tracking alcohol involved fatals for many years with traditional results showing alcohol as a main contributing factor.



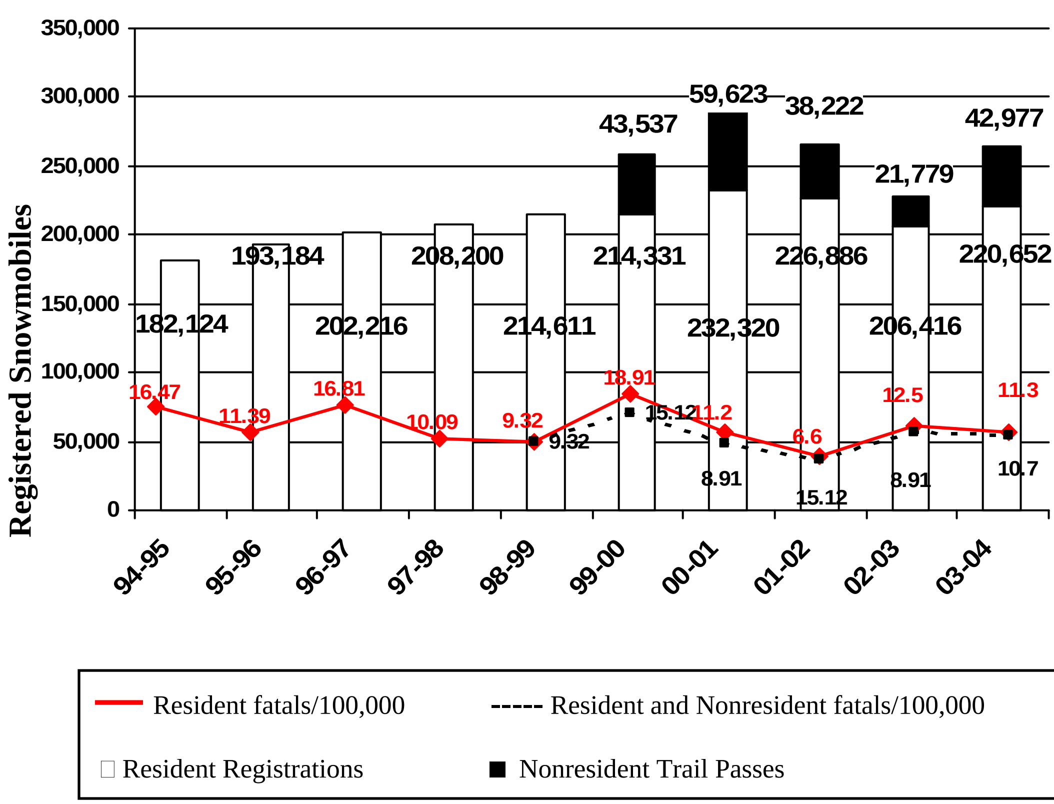
History of Snowmobile Fatalities



The 10-year fatal average is 25 deaths per year.

The amount of snowfall and number of hours ridden, are not reflected and can affect the number of fatals that occur.

Snowmobile Fatality Rate to Number of Snowmobiles Registered



Beginning the 1999-2000 season, the nonresident trail pass became required for all snowmobiles not registered in WI and as a result the Department was able to identify the number of nonresident snowmobiles operated in WI.

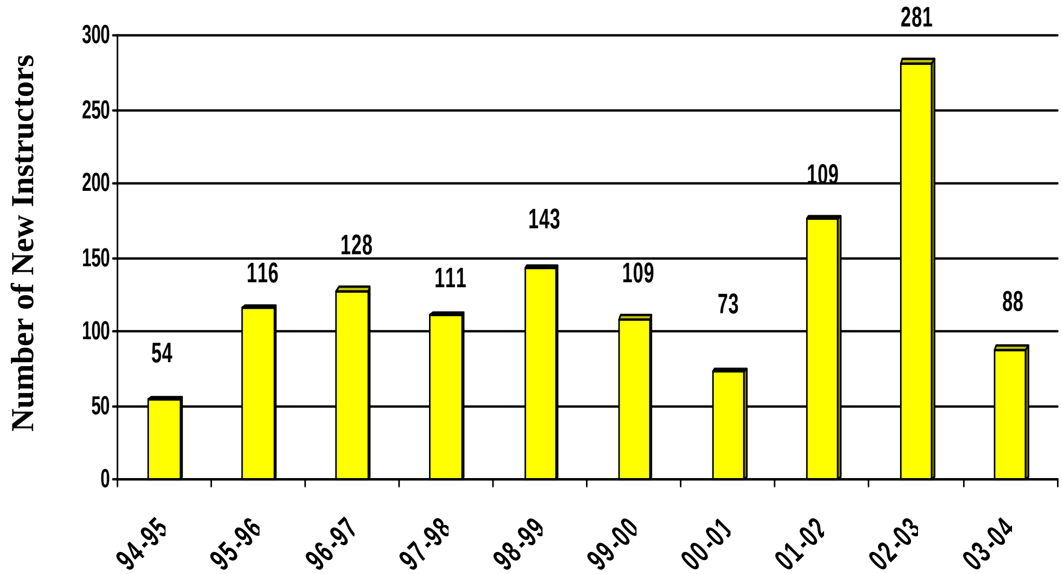
Fatals per 100,000 Registrations.

The total number of active instructors for 2003-2004 was 1,414. This number is up due to a push to activate new instructors largely with the help of the Association of Wisconsin Snowmobile Clubs.

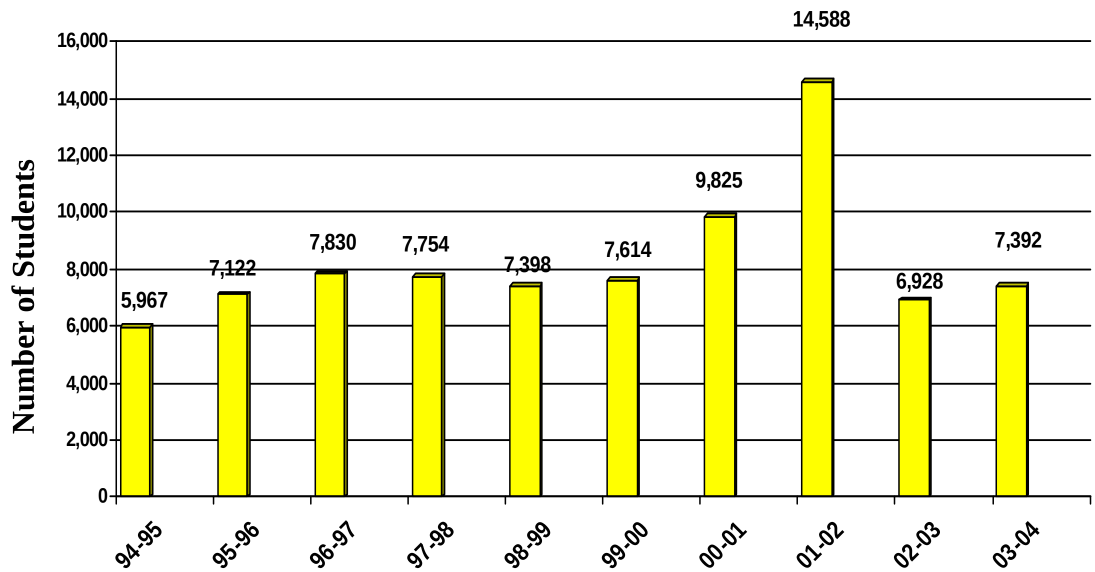
Over 239,631 students have been certified by volunteer instructors.

Certification requires a student to complete a basic Wisconsin snowmobile training course. Course content includes: knowing your snowmobile, maintenance and repair, riding, personal safety, winter survival, laws, courtesy and ethics.

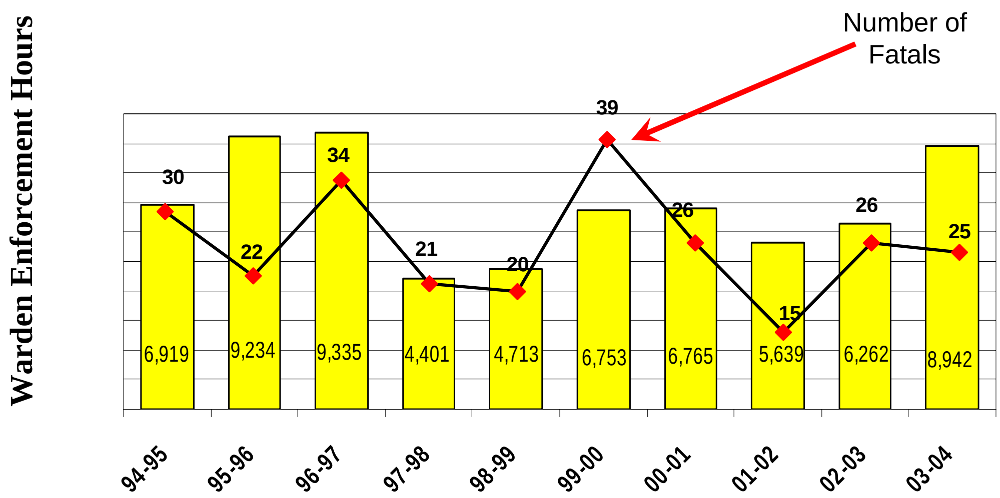
History of Newly Recruited Snowmobile Education Instructors



History of Certified Snowmobile Students

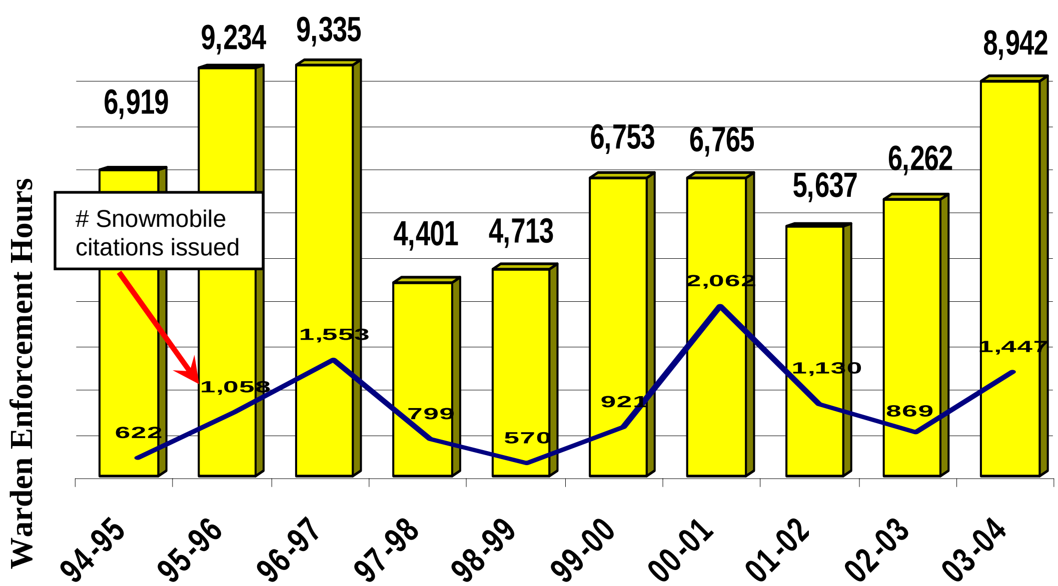


History of Snowmobile Fatality Rate to Warden Enforcement Hours



In 1999-2000, the department changed the tracking method used to collect data on the hours spent for enforcement issues. As a result, enforcement hours no longer include time involved with court, snowmobile maintenance, etc. and are more representative of the actual enforcement hours used.

History of Snowmobile Citation Rate to Warden Enforcement Hours



The citations for sheriff patrols and wardens were combined for the first time 2000-2001.

Prior to 2000-2001, the citations listed are for wardens only.

*See page 13 for explanation.

2003-2004, the average blood alcohol level for all victims reached 0.144.

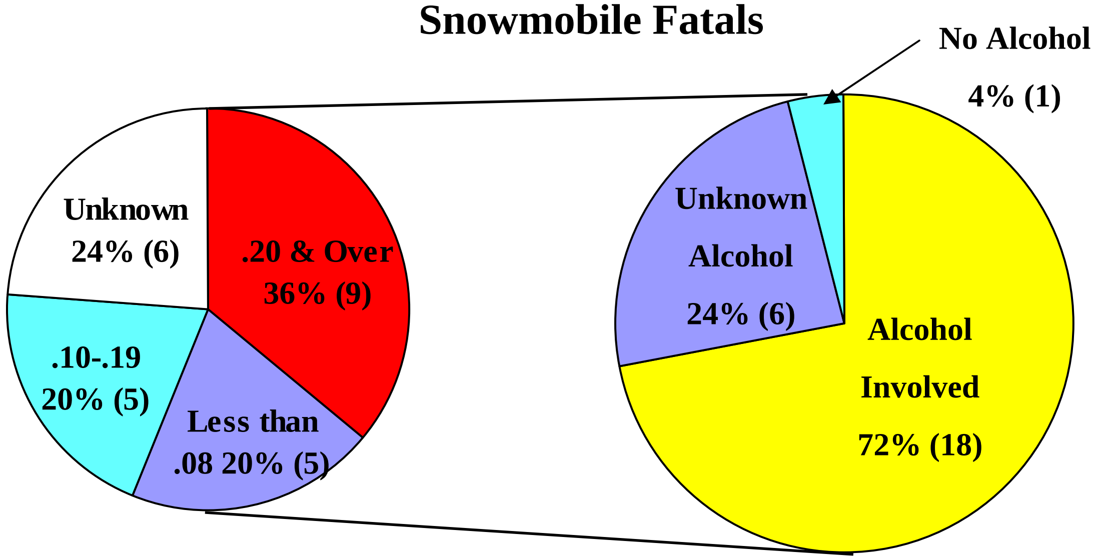
The average victim blood alcohol levels for 2002-2003 decreased to 0.144.

The 2003-2004 season showed that alcohol was a contributing factor in 72% of all fatals.

One 2003-2004 alcohol involved fatal was recorded at 0.284

The average age for the victims killed was 35.2 years old as compared to 35.3 years in 2002-2003.

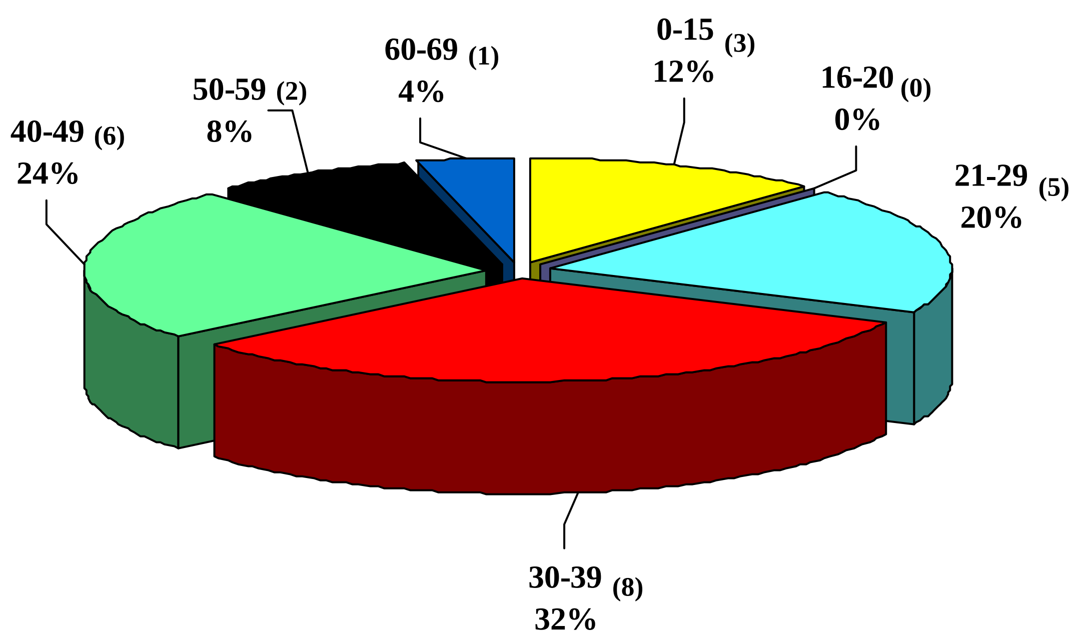
2002-2003 Alcohol Involved Snowmobile Fatals

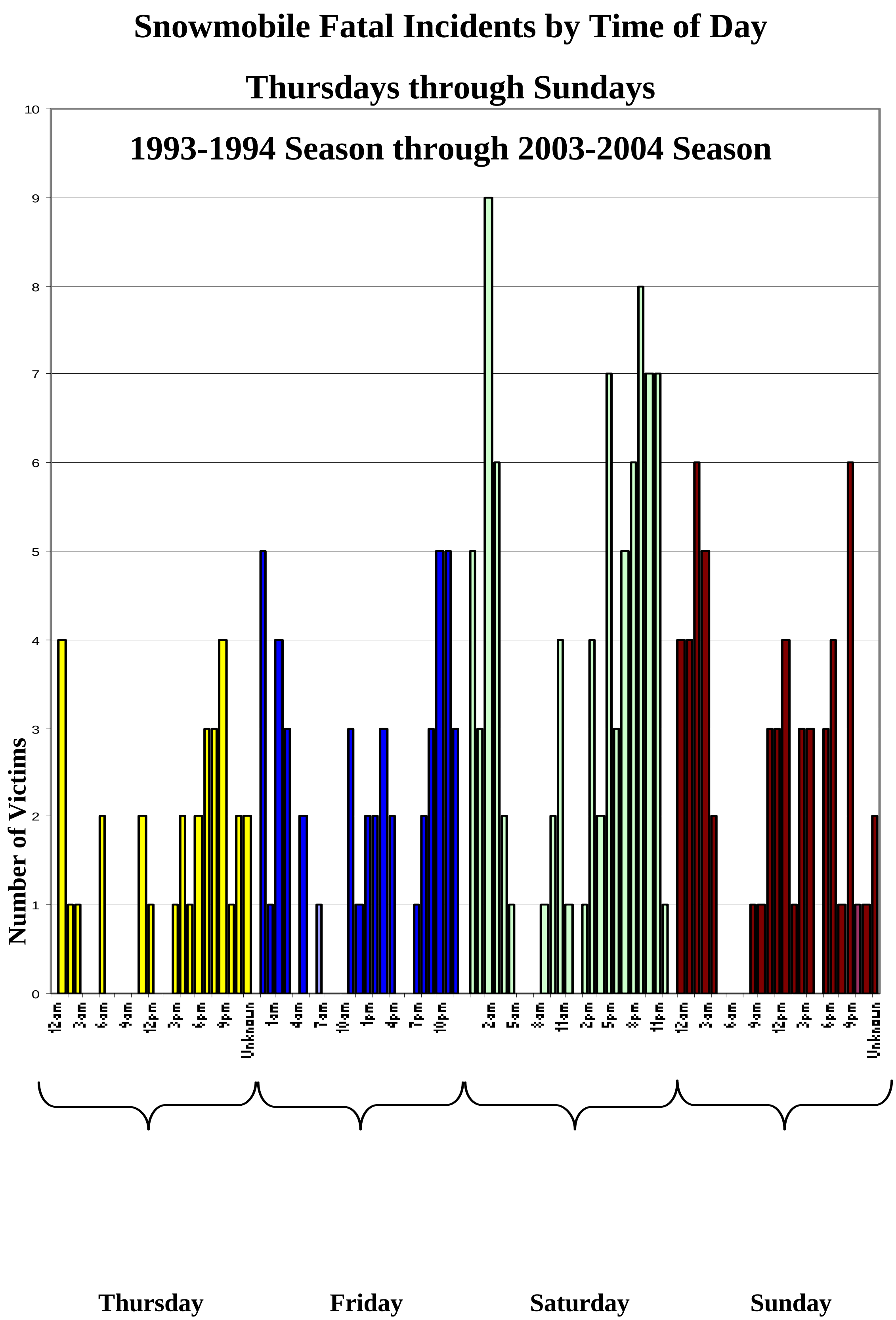


- Numbers in ( ) represents number of victims.

- Blood alcohol content is grams/ml.

2003-2004 Age of Snowmobile Fatality Victims





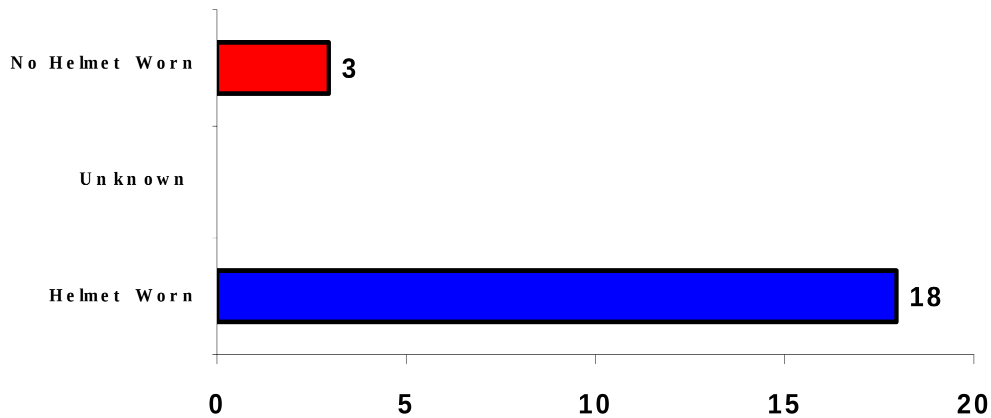
Fatal incidents have the highest frequency of occurrence on Saturday and Sundays.

The early morning hours generally involve single operator incidents.

Victims traditionally wear helmets.

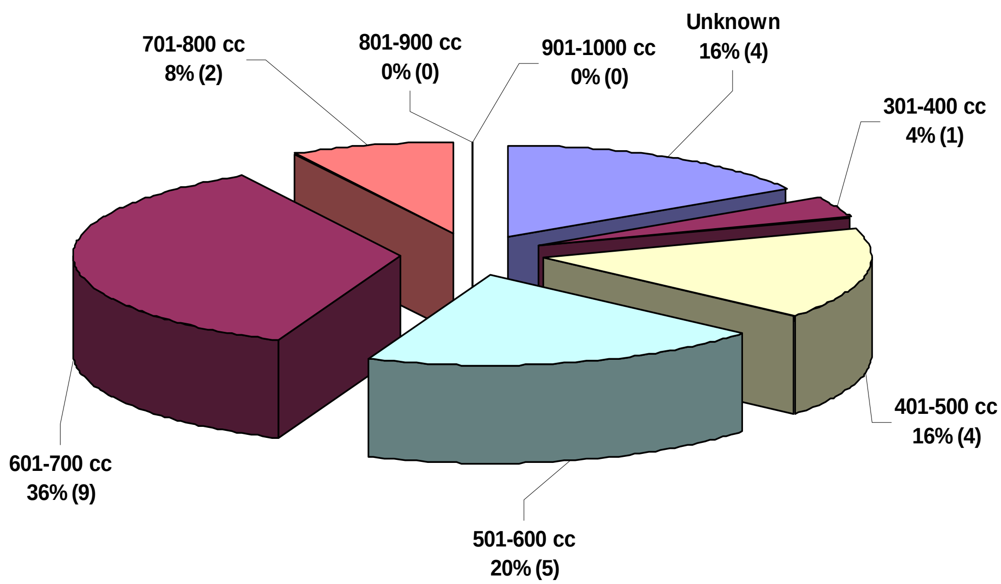
Unknown helmet use is because the victim was missing (drowned) or the helmet was not on the victim at the time of discovery.

2003-2004 Fatal Snowmobile Victim Helmet Use



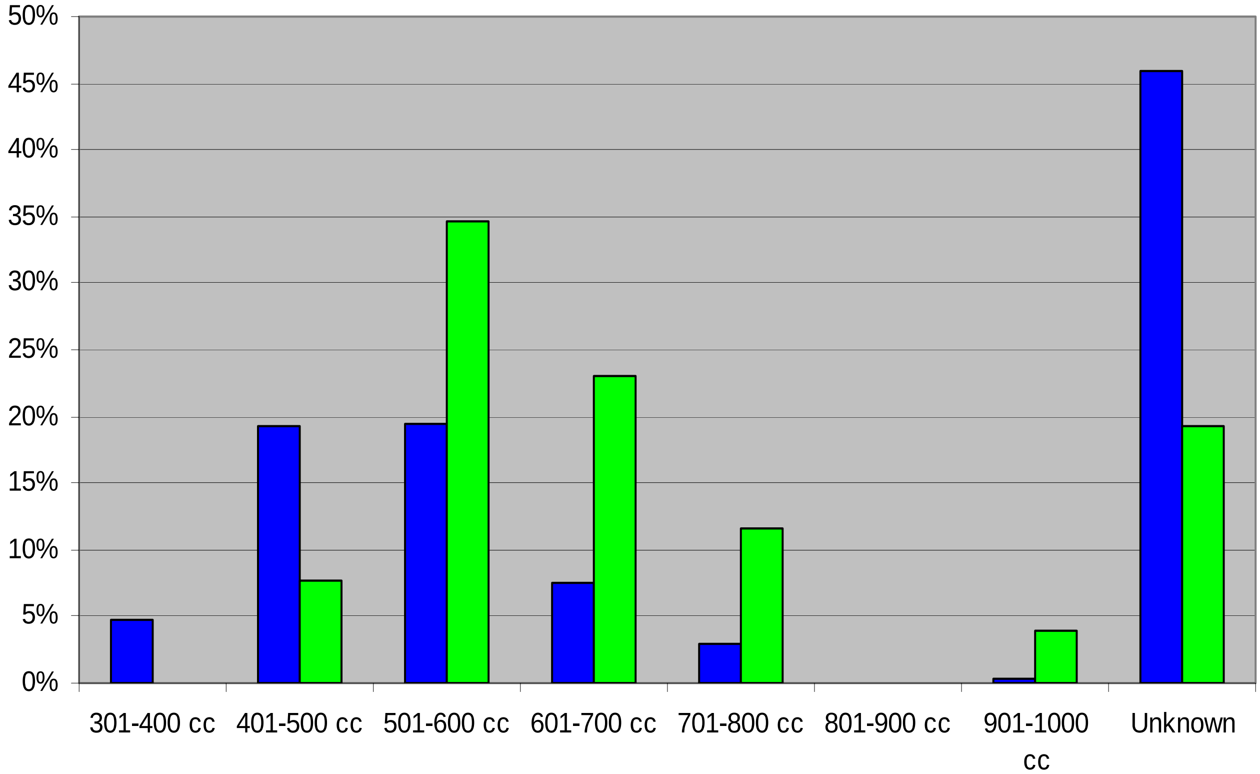
Historically, the 500 CC engine-powered snowmobile has made up the greatest number of snowmobiles involved in fatal incidents.

2003-2004 Snowmobile Engine Displacement for Machines Involved in Fatal Snowmobile Incidents



2003-2004 All Wisconsin Registered Snowmobiles

Engine Displacement Compared to Victim Machines



2003-04 Fatal Victim Snowmobiles

2003-04 All WI Snowmobiles

Engine Displacement Determined by Registration Analysis

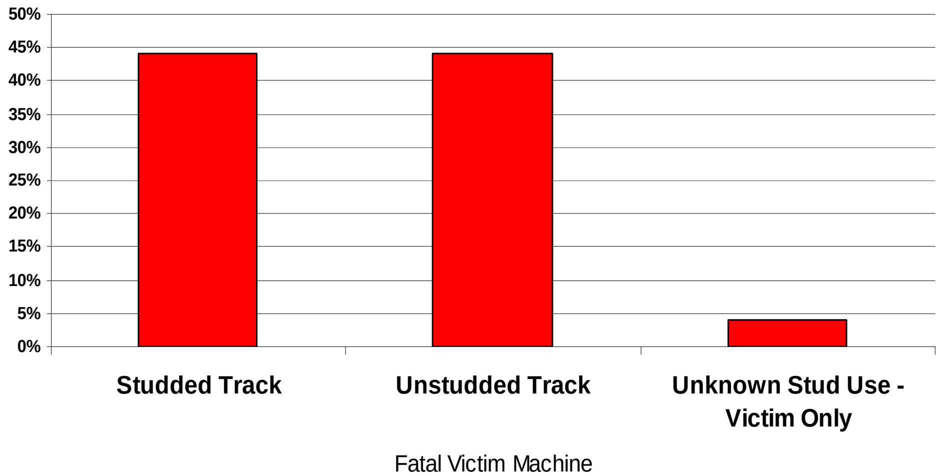
The Wisconsin snowmobile registration system contained unknown entries that either did not report a CC engine size displacement or the machine's engine capacity was recorded in horsepower units.

A survey of snowmobilers conducted in October 2001 indicates that 46.6% of the surveyed snowmobilers used studded tracks.

Source - Governor's Snowmobile Recreation Council, 10-12-01

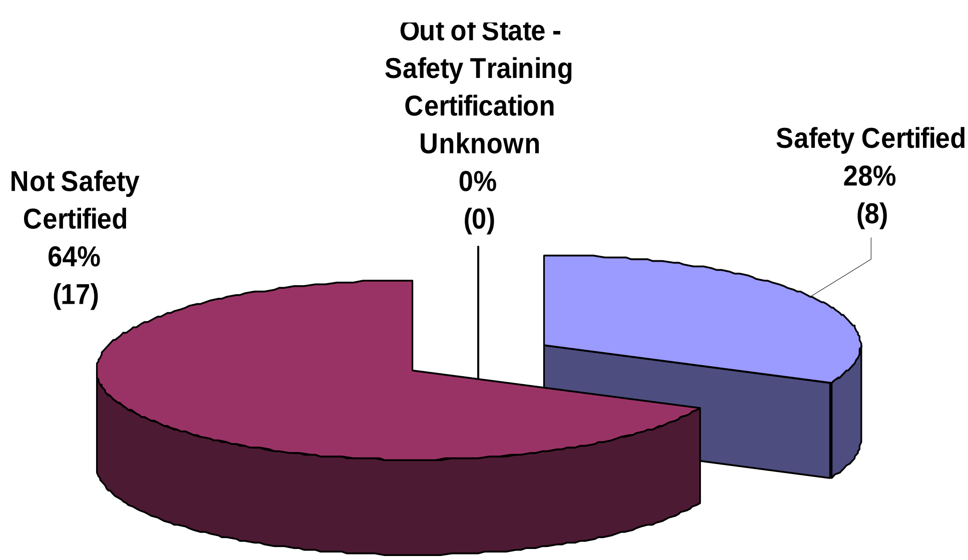
2003-2004 Studded Snowmobile Track

Fatality Victim's Use



Beginning January 1, 2001, a Snowmobile Safety Certificate became required for all operators born on or after January 1, 1985.

2003-2004 Fatal Snowmobile Victim Operators with Wisconsin DNR Safety Training Certification



2003-2004 Citations Issued for Snowmobile Violations

Total Citations	**1,447**
Operate Snowmobile w/o Valid Registration (S-1)	237
Fail to or Improper Display of Registration Number or Decal (S-2)	112
Operate Snowmobile w/o Possession of Valid Certificate (S-3)	168
Fail to Transfer Registration of Snowmobile (S-4)	16
Give Permission to Operate a Snowmobile not Registered (S-5)	47
Transport Uncased Strung Bow on a Snowmobile (S-09)	2
Shoot From a Snowmobile (S-10)	1
Operate in Prohibited Area on Lands Controlled by DNR (S-11)	13
Highway and Roadway Violations (S-12)	184
Equipment Violation (S-14)	6
Permit Operation by Person Incapable Because of Age, Physical or Mental Disability (S-15)	32
Fail to Report Snowmobile Accident (S-16)	8
Operate at/in Unreasonable, Improper or Careless Speed/manner (S-17)	74
Fail to Display Lights when Required (S-18)	1
Trespass 'Sec. 350.10(6) through (13) Wis. Stats.' (S-19)	51
Miscellaneous (S-20)	4
Dealer Failing to Collect Fee & Submit Registration Applications (S-21)	0
Fail to Stop for Law Enforcement Officer (S-22)	2
Fail to Render Aid (S-23)	2
Operate Snowmobile while Intoxicated (S-24)	50
Operate Snowmobile with Alcohol Concentration Above .1% (S-25)	36
Refuse to Take Intoxicated Snowmobile Test (S-26)	8
Absolute Sobriety for Persons Under 19 (S-27)	1
Operate Snowmobile that Makes Excessive or Unusual Noise (S-28)	80
Operate Snowmobile w/o Muffler on Engine (S-29)	7
Cause Injury by Intoxicated Operation of Snowmobile (S-30)	1
Operate w/o Trail Use Sticker (S-33)	137
Operate (Manufacture or Seller) Snowmobile w/o Functioning Muffler (S-34)	4
Fail to Comply with Regulatory Signs (S-35)	147
Operate snowmobile w/o proof of training certificate (S-36)	25

Citations reflect Sheriff Patrol and Conservation Warden data.

Wisconsin Snowmobile Fatality Summary – 2003/2004 Season

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
1.	11/2/03	Town of Porterfield	Struck a utility pole/trees	24	.243	No
	02:45	Marinette County (Public Rd.)	Alcohol / Speed / Head Trauma	Male	WI	

The victim was operating on dry asphalt in the center of the roadway and went through a T-intersection hitting a utility pole guy wire, at that point the victim and snowmobile were impaled on a cluster of trees.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
2.	12/13/03	Town of Webb Lake	Struck the shoreline and trees	47	.125	No
	23:45	Burnett County (Lake)	Hypothermia / Head Injury / Alcohol	Male	WI	

Friends went out looking for the victim after he was reported missing on 12/14/03. It appears he was traveling on trail five on Big Bear Lake, missed the trail and struck the shoreline and then a tree.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
3.	1/9/04	City of Milwaukee	Struck a steel guide wire	15	Unk.	No
	20:28	Milwaukee Co. (Road)	Trauma / Impact Injury	Male	WI	

The victim hit a guy wire with his snowmobile and was found shortly thereafter by friends who were snowmobiling in the same area.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
4.	1/10/04	Town of Black Wolf	Struck an ice shove and thrown from the machine	31	.112	No
	19:57	Winnebago County (Lake)	Alcohol / Head Trauma / Impact Injury	Male	WI	

The victim was traveling approx. 40-50 mph., hit an ice shove and was thrown from the snowmobile.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
5.	1/10/04	Town of Sumner	Struck Trees / Rocks	41	.226	No
	22:19	Jefferson County (Lake)	Chest & Neck Trauma / Speed / Alcohol / Unfamiliar with area.	Male	IL	

While traveling at a high rate of speed the victim struck at least one rock and several trees and was then either knocked off or fell off the snowmobile.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
6.	1/15/04	City of Ashland	Fell through ice.	44	.204	Yes
	02:19	Ashland County (Lake)	Hypothermia / Drowning / Alcohol	Male	WI	

A report came in from a witness who said he had seen a snowmobile light on the ice of Lake Superior and stated shortly after it disappeared. A hovercraft was dispatched and a single snowmobile track was found going into the hole, with no tracks leading out of the area. A glove, helmet and boot were located floating in the open water. Victim later found.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
7.	1/18/04	Town of Minocqua	Struck Trees	60	.182	No
	03:15	Oneida County (Trail)	Alcohol / Speed / Head Injury	Male	WI	

The victim attempted to navigate a left-hand curve on a slight downhill grade when he struck two trees. Estimated speed at the time of accident is approx. 50 mph.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
8.	1/20/04	Town of Gillett	Struck Trees	15	Unk.	Yes
	20:18	Oconto County (Private Property)	Speed / Head Trauma	Male	WI	

The victim was test driving his machine in a hayfield after making some repairs and it appears that after going over a hill he went airborne and crashed into some trees.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
9.	1/21/04	Town of Omr	Struck Trees	33	.202	No
	02:09	Iron County (Trail)	Alcohol / Head Trauma	Male	MN	

The victim was traveling on a trail and struck the trees.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
10.	1/23/04	Town of Lakewood	Collision with trees.	47	Unk.	No
	10:50	Oconto County (Trail)	Internal Injuries / Trauma / Impact Injury / Speed	Male	WI	

The victims snowmobile left the trail and struck some small trees, coming to a rest against several large trees. The victim was found underneath his snowmobile.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
11.	1/25/04	Town of Germantown	Fell through ice.	42	.188	Yes
	22:30	Juneau County (Lake)	Drowning / Exposure / Alcohol	Male	WI	

When the victim failed to arrive at home after leaving the tavern a search party was formed and the victim was found near his snowmobile in the lake at the mouth of the Little Yellow River.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
12.	1/30/04	Town of Fifield	Struck trees.	33	.025	No
	19:30	Price County (Trail)	Alcohol / Head Injuries / Speed / Inexperience	Female	WI	

The victim traveled about 200 yards and failed to negotiate a right hand turn just past the crest of a hill. The victim struck a 5 ½ inch popple tree breaking and uprooting the tree. The victim was transported to a hospital and air lifted to another where she was pronounced dead on 2/4/04.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
13.	1/31/04	Town of Mountain	Hit by a snowmobile.	52	.000	No
	01:08	Oconto County (Pond)	Speed / Inexperience	Male	WI	

The victim, who was the leader in a group of three snowmobiles, was ahead of the others and rolled his snowmobile and was standing on the ice when he was struck by the second snowmobile in the group.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
14.	2/1/04	Town of Excelsior	Collision with stalled snowmobile	34	.010	No
	15:15	Sauk County	Alcohol / Closed head injury.	Male	WI	

The victim struck a stalled snowmobile over the crest of a hill and was ejected from his machine. The incident happened on 2/1/04 causing head injury. The victim passed away on 2/25/04.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
15.	2/7/04	Town of Sugar Camp	Hit by automobile.	15	Unk.	No
	15:36	Oneida County (Roadway)	Inexperience / Failure to yield	Male	WI	

The victim failed to stop for a stop sign and drove into the path of an automobile on the highway.

#	Date	Location	Type & Cause of death – Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
16.	2/8/04	Town of Caledonia	Hit by snowmobile	39	.220	No
	24:45	Racine County (Trail)	Alcohol / Asphyxia / Severe Leg Trauma	Male	WI	

The victim lost control of his snowmobile causing him to fall off. He was lying in the middle of the trail when a second snowmobile, operated by another person in the same group, ran him over.

#	Date	Location	Type & Cause of death – Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
17.	2/9/04	Township of Carey	Ran over by snowmobile	52	Unk.	No
	21:53	Iron County (Roadway)	Heart Attack	Male	MN	

It appears that the victim had fallen off his snowmobile and had been pulled by the track into the rear of the snowmobile.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
18.	2/13/04	Town of Belgium	Struck trees.	25	.020	No
	23:00	Ozaukee County (Trail)	Alcohol / Speed	Male	WI	

The victim took off at a high rate of speed through a wooded area on a snowmobile trail, missed a curve and hit the trees.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
19.	2/14/04	Town of Almena	Struck trees.	28	Unk.	No
	02:57	Barron County (Trail)	Hypovolemic Shock	Male	WI	

After failing to negotiate a curve in the trail the victim went off the trail and struck a group of trees.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
20.	2/18/04	Town of St. Germain	Collision with other snowmobile	38	.079	No
	22:30	Vilas County (Lake)	Internal Injuries / Alcohol / Speed	Male	IL	

Investigation indicates that snowmobiles were involved in an informal race on the lake. Estimated speed at the time of incident is approx. 95-110 mph. The incident happened near the end of the race when it appears that vehicle A struck vehicle B causing vehicle B to tumble over several times in a clockwise fashion while vehicle A began to tumble several times in a counter-clockwise fashion.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
21.	2/19/04	Village of North Hudson	Fell in open water.	29	.250	No
	04:00	St. Croix County (River)	Alcohol / Drowning / Hypothermia	Male	WI	

The victim failed to stop in time and encountered open water near the dam.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
22.	2/19/04	Town of Cleveland	Struck trees.	25	.284	No
	09:00	Jackson County (Trail)	Head Trauma / Speed / Alcohol	Male	WI	

The victim lost control of the snowmobile and did not make the turn onto the trail. The victim then went air born and was thrown from the snowmobile into a tree.

#	Date	Location	Type & Cause of death – Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
23.	2/28/04	Town of Fifield	Struck shoreline / trees	33	.249	No
	01:00	Price County (Lake)	Speed / Alcohol / Trauma / Impact Injury	Male	IL	

The victim was third in a line of four snowmobiles and it is unclear what took place as other members of the snowmobile party did not observe the incident. The victim's snowmobile went airborne for 15 feet 6 inches and landed at the base of some oak trees. The snowmobile hit the tree where the right front ski connects to the snowmobile.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
24.	2/29/04	Town of Dairyland	Struck trees.	44	.202	No
	24:35	Douglas County (Road)	Speed / Alcohol / Head and Internal Injuries	Male	WI	

The victim was traveling at a high rate of speed on the trail across the lake. The victim traveled to the right of the trail striking the shoreline and a stump. The victim was thrown from the snowmobile and struck a tree.

#	Date	Location	Type & Cause of death - Primary/Secondary	Age/ Sex	BAC/ Residency	Safety Certified
25.	3/15/04	Town of Mercer	Struck by snowmobile	36	.162	No
	03:00	Iron County (Trail)	Alcohol / Neck / Internal Injuries	Male	IL	

The victim had gone around a corner and down a hill and had likely slowed down or stopped. He was then struck by the following snowmobile.

SLOW DOWN

...RIDE SOBER…

&

RIDE FOR LIFE

Notes

ATTACHMENT 3

Woman killed after snowmobile hits wire

CBC News
Posted: Feb 28, 2011 9:44 AM CST
Last Updated: Feb 28, 2011 9:44 AM CST

A 48-year-old woman died after a snowmobile she was riding on collided with a hydro pole guy wire in southern Manitoba.

According to police, the woman was a passenger on the machine when it struck the wire at about 7:30 p.m. at the intersection of Highway 12 and Hanover Road, just south of Steinbach.

The woman, a resident of Steinbach, was pronounced dead at the scene.

The 43-year-old man who was driving the snowmobile was transported to the Bethesda Hospital where he was treated for minor injuries and released.

Alcohol was not a factor in the accident, RCMP said.

No further information is available at this point.

Police have not said whether any charges are pending.

A guy wire is a cable anchored into the ground and fastened to the pole to strengthen it and keep it in position.

ATTACHMENT 4

NEWS LOCAL

Man killed in snowmobile crash

Mark Melnychuk
Friday, February 25, 2011 9:49:00 CST AM

A wreath rests beside Highway 4, where Tracy Abbott lost his life in a snowmobiling accident on Feb. 19. The crash occurred approximately 62 km south of Meadow Lake.Photo By Mark Melnychuk

Saskatchewan has seen a rash of fatal snowmobile accidents this winter, but some feel the latest tragedy could have been prevented.

Tracy Abbott, 47, was killed on Feb. 19 when he collided with a power pole's metal guide line. He was pronounced dead at the scene.

The accident occurred 62 km south of Meadow Lake on Highway 4 at approximately 2:51 p.m.

Abbott was participating in a snowmobile rally when he veered off the groomed route, taking him further down the highway.

Abbott was from Lloydminster, SK. Police do not believe alcohol was a factor in the accident.

Philip Pilat, a close friend of Abbott, said there's no doubt in his mind that the accident could have been avoided had SaskPower made the wires safe for snowmobilers.

"It should be safe. It should be up to SaskPower to make sure that things are safe," said Pilat.

Pilat said there were no visible markers on the wire, and that the angle of the wire was too close to the ground.

"I love him, I miss him and I feel for his family," said Pilat.

RCMP investigators also believe the low-hanging line could have been a factor.

"It's a possibility that at that angle they could be a little harder to see," said Cpl. Kim Gobeil, Meadow Lake RCMP detachment.

Although there is a plastic safety guard at the end of the wire, RCMP investigators said it was covered with snow at the time of the accident. Gobeil said the RCMP may make a recommendation to SaskPower concerning the guy wires.

SaskPower responded by launching an investigation into the tragedy. An employee was sent out on Feb. 22 to inspect the site where the accident occurred.

A representative of SaskPower said the angle of the pole's guy wire is chosen depending on the height of the pole and the terrain it rests upon.

The company said it follows the Canadian Electrical Code's mandate that wire safety guards should be built sturdily and made a colour that's easily visible. However, SaskPower said they can't be there to remove snow from all 157,000 km of its power lines that run throughout the province.

"There are a lot of power cables in the province, and a lot of guide wires and it's just not practical for us to go along and remove snow from guide wires," said James Parker, a spokesperson for SaskPower.

Parker said the company would also be willing to cooperate with the RCMP's investigation in any way it can.

The accident was the second snowmobiling death to occur last weekend. A woman was killed on Feb. 19 in Candle Lake Provincial Park when she collided with a group of trees.

So far this winter, the province has seen a startling number of snowmobile related deaths, prompting the Saskatchewan Snowmobilers Association to remind snowmobilers to ride safely.

ATTACHMENT 5

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

IN THE MATTER OF: Application of NEVADA POWER COMPANY d/b/a NV Energy Seeking Acceptance of its Triennial Integrated Resource Plan covering the period 2013-2032 and Approval of its Energy Supply Plan for the period 2013-2015.	Docket No. 12-06___

VOLUME 16 OF 24
IRP SUPPLY SIDE PLAN, TRANSMISSION PLAN, ECONOMIC ANALYSIS AND FINANCIAL PLAN

NEVADA POWER COMPANY d/b/a NV ENERGY 2013-2032 INTEGRATED RESOURCE PLAN

SUPPLY SIDE PLAN, TRANSMISSION PLAN, ECONOMIC ANALYSIS, AND FINANCIAL PLAN

Table of Figures

SECTION 1. INTRODUCTION

This volume of the Nevada Power Company d/b/a NV Energy ("Nevada Power," "NPC," or "Company") 2013 – 2032 Integrated Resource Plan (the "2012 Resource Plan" or "2012 IRP") presents the Supply Side Plan, the Economic Analysis used to select the Preferred Plan and the Alternative Plan, and the Financial Plan.

Strategic Plan

Nevada Power's strategic plan is to provide clean, safe, reliable electricity to its customers at reasonable and predictable prices by:

1. Empowering customers through more focused energy efficiency programs;
2. Pursuing cost-effective renewable energy initiatives;
3. Optimizing generation efficiency and transmission; and
4. Engaging employees to improve processes, reduce costs and enhance performance.

Supply Side Plan

Generation and PPAs. With the Commission's leadership and support, Nevada Power has significantly reduced its reliance on volatile wholesale markets in recent years. In 2008, Nevada Power generated just 67.5 percent of its total energy requirements from Company-owned facilities, while purchasing the remaining 32.5 percent from neighboring utilities and renewable energy developers. Since then Nevada Power has completed the Goodsprings Heat Recovery Unit project and the Harry Allen combined cycle facility. Even with the retirement in December 2011 of the Sunrise Units 1 and 2, Nevada Power now has sufficient Company owned and/or controlled generation to meet most of its customers' current needs.

Utilizing the results of the long-term load forecast, the demand-side management plan ("DSM Plan") and the renewable energy plan, Nevada Power identified the Company's resource requirements over a full thirty-year planning period. This analysis indicates that Nevada Power does not need to add incremental supply side resources until 2018. The Preferred Plan assumes that the Company will construct a block of simple-cycle combustion turbines (375 MW) in 2018, and additional units in 2021. However, the Company is not requesting authority to proceed with the acquisition or construction of any of these natural gas-fired peaking units at this time. The Company is limiting its Action Plan request to authorization to expend sufficient funds ($9.95 million) to identify sites and begin initial permitting activities for new generating units.

The Company's existing power exchange agreement with the Southern Nevada Water Authority ("SNWA") expires on May 31, 2013. Nevada Power is seeking approval of a new agreement to take effect on June 1, 2013 and extend through December 31, 2018. As with the Existing Power Exchange, the Second Power Exchange will provide Nevada Power the right to dispatch SNWA's 25% share of the Silverhawk plant. When Nevada Power utilizes SNWA's share of Silverhawk under the Second Power Exchange, Nevada Power will once again be responsible for providing the natural gas necessary and will also pay the variable O&M rate associated with the Silverhawk plant. In the Second Power Exchange, Nevada Power will also deliver to SNWA at the Mead 230 kV substation, 125 MW of firm energy during on-peak hours (7x16) and 25 MW of firm energy during off-peak hours (7x8). The transaction benefits Nevada Power's customers.

Renewables and DSM

The Renewable Portfolio Standard ("RPS") requires the Company "to generate, acquire or save electricity from portfolio energy systems or efficiency measures" in amounts that are prescribed by statute. See NRS 704.7821 (as amended by SB 358, 2009 Session). In 2009 Nevada's aggressive RPS was amended to increase the percent of retail load that must be met with renewable resources. In 2011 the RPS increased to 15 percent of retail load, and will grow to 18 percent in 2013, 20 percent in 2014, 22 percent in 2020, and 25 percent in 2025. Nevertheless, the Company is well poised to comply with the RPS through the Action Plan period with a portfolio of diverse renewable resources. Nevada Power must vigilantly monitor execution of previously approved renewable plans, adjust to any changes in the delivery of renewable energy and portfolio credits from its existing portfolio of renewable projects and pipeline of projects, and continue investing in effective energy efficiency programs.

Transmission

WestConnect. Nevada Power and Sierra are members of the WestConnect Steering Committee and WestConnect Transmission Planning Committee, and are seeking Commission authorization to fund the continued participation in WestConnect during the 2013-2015 Action Plan Period. The Action Plan budget reflects an increase in the cost of participating in WestConnect due to the mandates of FERC Order 1000. Nevada Power's share of these costs is estimated as $146K in 2013, $150K in 2014, and $154K in 2015.

ONE Nevada Transmission Line ("ON Line"). Around the first of December 2011, high sustained winds were experienced in Eastern Nevada in the area of construction. Crews working on the project observed damage to several of the tower structures after the winds subsided. The cause of the damage has been since attributed to wind-induced vibration experienced when the tubular guyed-V structures are exposed to sustained winds. Efforts to address the wind-induced vibration issues are continuing. Assisted by industry experts, the Owners are analyzing different mitigation measures to safely and cost-effectively address the wind-induced vibration observed in the structures. At this time, the Owners do not anticipate recommencing installation of tubular guyed-V structures for the ON Line project until all computer analysis, wind tunnel testing, and field testing of mitigation measures have been completed and the results have been analyzed to ensure safety and reliability of the structures under all reasonably anticipated wind conditions.

Because the schedule and budget for ON Line have been revised, the Companies have prepared two different types of analyses to confirm the reasonableness of a decision to proceed with the ON Line: a sunk cost analysis and traditional resource planning analysis using updated planning inputs (i.e. load forecast, purchased fuel and power costs, carbon and Greenhouse Gas costs, cost of renewables, etc.). The results of the sunk cost analysis confirm the economic reasonableness of a decision to proceed with constructing the ON Line, assuming satisfactory resolution of the wind-induced vibration issues. The results of the conventional resource planning analysis confirm that while the economic benefits of the project have changed since the Commission's Order in Docket No. 10-02009, the project still provides a net positive benefit. Again assuming satisfactory resolution of the wind-induced vibration issues, it is reasonable to proceed with constructing the ON Line with the revised budget and according to the revised schedule.

Economic Analysis and the Preferred Plan

The 2012 Resource Plan evaluates the present worth of revenue requirements ("PWRR") of various expansion plans in order to determine which alternative has the lowest PWRR over 20 and 30-year planning horizons. The Company's IRP decisions must take into account an assessment of risk with respect to cost, reliability, finances and exposure to fuel and power price volatility. The intent of the analysis is to determine the expansion plan that will provide the greatest savings to Nevada's Power's customers while also meeting the RPS and environmental requirements and considering other relevant factors such as fuel diversity, operational flexibility, and related economic planning considerations. Nevada Power developed four alternative expansion plans for meeting its projected long-term needs for incremental capacity and energy. The Company evaluated the alternative expansion plans with sensitivities around high and low load forecasts, high and low fuel and purchase power price forecasts, and high and low carbon forecasts. In addition, an economic analysis of the four plans with and without external system power sales was performed.

The Preferred expansion plan centers on conventional gas-fired technologies-- a block of simple-cycle combustion turbines (375 MW) in 2018, and additional units in 2021. The Company is not requesting authority to proceed with the acquisition or construction of any of these gas-fired generating units at this time. The Company is limiting its Action Plan request to authorization to expend sufficient funds ($9.95 million) to identify sites and begin initial permitting activities for future generating units. By remaining focused on preserving future resource options, Nevada Power maintains least cost options for customers while continuing to protect customers from exposure to potentially volatile energy markets.

Financial Plan

The analysis contained in the Financial Plan shows that the Company has the financial capacity to finance the Preferred Plan, both as modeled in the Financial Plan and as specified in the Action Plan.

SECTION 2. SUPPLY SIDE PLAN

A. GENERATION

1. EXISTING AND PREVIOUSLY APPROVED GENERATION

(A). SUMMARY

Nevada Power's net portfolio of generation capacity has increased by approximately 339 MW[1] since the Commission issued its Order (dated July 30, 2010) in the 2009 Resource Plan, Docket No. 10-02009. In late 2010, the Goodsprings Heat Recovery renewable project entered into service, and in 2011, Nevada Power completed construction of the Harry Allen Combined Cycle. These capacity additions were partially offset by the retirement of Sunrise Units 1 and 2.

An overview of existing renewable and fossil-fired generation is provided below. This section also includes an update on the retirement of the Sunrise Units 1 and 2, Brownfield Site Selection Study, the final transfer of ownership of Reid Gardner Unit 4, the status of environmental regulations affecting the coal units in the Nevada Power Fleet, Navajo Generation Station Uncertainty, and an explanation of the Generation Technology options utilized in the expansion plan analysis for this IRP.

(B). EXISTING GENERATION

Nevada Power holds an ownership interest in 4,340 MW (total peak summer capacity) of resources composed of the following generating facilities:

- Clark Generating Station: 1,102 MW of total peak summer capacity, located in Las Vegas. Clark Station is composed of two 2x1 natural gas-fired combined cycle units (430 MW), one natural gas-fired combustion turbine unit (54 MW), and twelve natural gas-fired simple cycle combustion turbines (618 MW).

- Chuck Lenzie Generating Station: 1,102 MW of total peak summer capacity including duct burners and inlet chillers. The plant is located approximately twenty-four miles northeast of Las Vegas and is composed of two 2x1 natural gas-fired combined cycle units (551 MW each).

- Goodsprings Heat Recovery: 7.5 MW (summer peak) waste heat recovery project is adjacent to the Kern River Goodsprings compressor station. The unit captures heat from Kern River's natural gas-fueled compressors, and uses a separate generator to produce electricity.

[1] Summer peak capacity.

- Harry Allen Generating Station: 628 MW of total peak summer capacity, located twenty-four miles northeast of Las Vegas. The Harry Allen Generating Station is comprised of the new 484 MW natural gas-fired Harry Allen Combined Cycle facility, as well as 144 MW of natural gas-fired combustion turbine peak summer capacity generated by two gas-fired turbine units (72 MW each). The 484 MW (peak summer capacity) natural gas-fired Harry Allen CC became commercially available in May of 2011.

- Navajo Generating Station: Nevada Power has rights to 255 MW of net capacity, which reflects an 11.3 percent ownership share of the Navajo Station, a 2,250 MW total net capacity facility located near Page, Arizona. The facility is composed of three similar coal-fired steam turbine units (750 MW each). The units are co-owned by a number of parties with Salt River Project serving as the operator.

- Reid Gardner Generating Station: 557 MW of total peak summer capacity, located fifty-two miles northeast of Las Vegas, composed of three similar coal-fired steam turbine units (100 MW each) as well as one larger coal-fired steam turbine unit (257 MW) that is co-owned with the California Department of Water Resources ("CDWR"). Nevada Power currently has rights to 25 MW of base load energy from the larger coal unit ("RG4") as well as interruptible energy rights to most of the remaining share. Nevada Power operates RG4 until it takes full ownership of the facility in 2013. Nevada Power can store an estimated maximum of 1.8 million tons of coal on site at Reid Gardner.

- Silverhawk Generating Station: 520 MW of total peak summer capacity, including duct burners, located approximately twenty-six miles northeast of Las Vegas. The plant is composed of one 2x1 natural gas-fired combined cycle unit and is co-owned by Nevada Power and the Southern Nevada Water Authority ("SNWA"). Nevada Power has a 75 percent ownership (390 MW) share and is the operator of the unit. Nevada Power and SNWA currently have a Long-Term Power Exchange Agreement regarding SNWA's twenty-five percent interest, which expires in 2013. The Action Plan includes a request to approve an amendment to this agreement.

- Walter Higgins Generating Station: 530 MW of total peak summer capacity including duct burners, located approximately thirty-five miles southwest of Las Vegas, composed of one 2x1 natural gas-fired combined cycle unit.

Figure SS-1 summarizes Nevada Power's renewable and fossil-fired generation facilities. Additional information regarding the operating parameters of each unit is contained in the Unit Characteristics Table, which is provided as Confidential Technical Appendix Item GEN-1. It should be noted that the fixed and variable costs shown in GEN-1 are the recently updated costs that were used in the Reid Gardner investigatory docket and are currently being used for dispatch of the units.

FIGURE SS-1 - NEVADA POWER GENERATING UNITS SUMMARY

Unit	Commercial Operation Date	Depreciation Based Retirement Date	Prime Mover	Designation	Name Plate (MW)	Winter Capacity (MW)(1)	Summer Capacity (MW)(1)	Summer Capacity at Peak (MW)(1)	Fuel Types	Fuel Storage
Chuck Lenzie 1	2006	2041	CC/ Steam	Intermediate	610	601	585	551	Gas	none
Chuck Lenzie 2	2006	2041	CC/ Steam	Intermediate	610	601	585	551	Gas	none
Clark 4	1973	2020	CT	Peak	60	63	55	54	Gas	none
Clark 7,8,9	1980,1982, 1993	2033	CC/ Steam	Intermediate	236	250	230	215	Gas	none
Clark 5,6,10	1979,1979, 1994	2034	CC/ Steam	Intermediate	236	250	230	215	Gas	none
Clark 11 – 22	2008	2038	CT	Peak	726	684	624	618	Gas	none
GoodSprings	2010	2040		Base	7.5	6	5	5	Waste Heat	none
Harry Allen 3	1995	2025	CT	Peak	72	84	74	72	Gas	none
Harry Allen 4	2006	2036	CT	Peak	72	84	74	72	Gas	none
Harry Allen CC	2011	2046	CC/ Steam	Intermediate	558	524	510	484	Gas	none
Reid Gardner 1	1965	2020	Steam	Base	121	100	100	100	Coal	120 days
Reid Gardner 2	1968	2020	Steam	Base	121	100	100	100	Coal	120 days
Reid Gardner 3	1976	2020	Steam	Base	116	100	100	100	Coal	120 days
Reid Gardner 4 (1)	1983	2023	Steam	Base	270	257 (25 NPC)	257 (25 NPC)	257 (25 NPC)	Coal	120 days
Silverhawk(2)	2004	2039	CC/ Steam	Intermediate	599	599	560 (420 NPC)	520 (395 NPC)	Gas	none
Navajo 1-3 (3)	1974-1976	2024,2025, 2026	Steam	Base	255	255	255	255	Coal	180 days
Walter Higgins	2004	2039	CC/ Steam	Intermediate	688	600	550	530	Gas	none

Notes:
1. RG4 is co-owned with CDWR but operated by Nevada Power. Nevada Power has rights to 25 MW of base load energy and interruptible energy rights to most of the remaining share.
2. Silverhawk is co-owned by Nevada Power (75 percent) and SNWA (25 percent). Nevada Power is the operator of the unit. Nevada Power and SNWA have a Long-Term Power Exchange Agreement regarding SNWA's twenty-five percent interest.
3. Navajo is composed of three similar coal-fired steam turbine units (750 MW each or 2,250 MW total). The units are co-owned by a number of parties with Salt River Project serving as the operator. Nevada Power's ownership share of Navajo is 11.3% or 255 MW.

(C). Sunrise Retirement Status

In its Order in Docket No. 11-08011, the Commission approved Nevada Power's request to retire the Sunrise units on December 31, 2011. Immediately following the Commission's Order, Nevada Power began the engineering and construction required to separate the Sunpeak generating units from the Sunrise units. Separation was required because the Distributed Control System ("DCS") cabinets, switchyard relays and other controls dedicated to the Sunpeak units were located inside the Sunrise 1 control room. With the impending demolition of the Sunrise Station, these controls were required to be moved to a new location. The existing electrical and instrumentation shop building adjacent to the Sunpeak units was chosen to house the Sunpeak cabinets and relays, and has been retrofitted to accommodate the relocated controls. Additional work was required to separate the fuel systems, auxiliary plant power, water supply for plant operations and fire control, and waste water evaporation pond. The work was completed on May 1, 2012, to ensure that the Sunpeak units are able to operate independently during the peak season of 2012.

The current cost estimate for the entire demolition and decommissioning of the Sunrise Units is $13.8 million, which includes approximately $4 million in costs associated with the separation of the Sunpeak plant from the Sunrise plant. This is higher than the cost estimated and presented in Docket No. 11-08011, primarily because of the work necessary to separate the Sunpeak Units which was not included in the previous estimates. The actual decommissioning is being bid at this time and better estimates of demolition and salvage will be available in July 2012.

(D). Brownfield Site Study

In Docket No 10-02009, the Commission approved Nevada Power's request to study potential sites for brownfield generation projects in Southern Nevada. The order provides:

> *NPC will perform a preliminary assessment of opportunities for expansion in 'brownfield' sites which are sites in and around existing NPC generating facilities. Should include Reid Gardner, Harry Allen and Sunrise. Although the opportunities may be limited in some areas due to air emissions criteria discussed above, it may be possible to make use of offsets associated with the retirement or shutdown of existing facilities, and make use of a site with existing land and infrastructure in place.*

The study originally included the evaluation of brownfield sites at Harry Allen, Reid Gardner and Sunrise facilities, but was subsequently expanded to study brownfield opportunities at Higgins, Silverhawk, and Mohave plant sites. The primary work product is a matrix of options for each site that identifies type of development options available, the best fit for each site considering land status, estimated cost, and environmental requirements.

The Commission approved a budget of $600,000 for the brownfield site, of which approximately $190,000 has been spent. The analysis is included in Technical Appendix GEN-3.

(E). REID GARDNER 4 ("RG4") PARTNERSHIP TERMINATION

In 1979, Nevada Power and CDWR began to construct RG4 under a Partnership Agreement ("PA") that governs its joint ownership and operation. A copy of the PA is included in Technical Appendix GEN-2.The PA specifically identifies three ways in which the agreement may be terminated: 1) upon retirement; 2) upon mutual agreement in the event RG4 is unable to obtain initial operation; or finally 3) upon expiration "30 years after the Date of Firm Operation."[2] Moreover, termination may occur only upon settlement or payment of all monies owed by one party to the other.[3] Firm Operation was established as of July 25, 1983.[4] Nevada Power does not anticipate that unsettled past or future obligations will remain owing at expiration. Accordingly, in compliance with the agreement, the PA will terminate as of July 25, 2013.

While termination is conditioned upon full payment of amounts owed, Nevada Power's payment is not subject to further conditions. The PA dictates that "[a]t the termination of this agreement, Nevada [Power] shall pay [CDWR] for any undepreciated cost of Capital Improvements for Reid Garner No. 4."[5] "[CDWR's] undepreciated cost of Capital Improvements shall be determined by using 30-year sinking fund depreciation for all Capital Improvements using the interest rates determined pursuant to Section 23.2."[6]

Under the terms of the PA, Nevada Power is obligated to pay CDWR for its share of RG4 on July 25th, 2013 and assume full ownership at that time. Nevada Power and CDWR are currently engaged in discussions to confirm and validate the documentation that will be used to quantify the cost of Capital Improvements and the interest rates to be utilized in the depreciation calculation. In addition, Nevada Power and CDWR are drafting a termination agreement to cover the logistics of the transaction. Nevada Power reported an estimated termination obligation in its 2011 10-K filing of approximately $42,700,000. This estimate was calculated using Nevada Power's own book value of RG4 and is subject to change with the completion of data validation.

CDWR presently participates in a share of the obligations incurred as a result of an Administrative Order on Consent ("AOC") with the Nevada Division of Environmental Protection ("NDEP") governing current and future operations at Reid Gardner Station.

[2] PA Section 29
[3] PA Section 29
[4] MOA 33, dated July 25, 1983
[5] PA Section 31.6
[6] PA Section 31.7

NPC and CDWR are currently engaged in discussions to reach an agreement establishing responsibility for ongoing AOC costs following termination of the PA. Nevada Power anticipates that those discussions will be concluded prior to expiration to ensure full payment of past and future monies owed under the AOC upon termination.

(F). ACTIVE AIR REGULATIONS AFFECTING COAL PLANTS

Regional Haze – Reid Gardner Station Units 1, 2, & 3

The EPA's Regional Haze Rule requires the State of Nevada (and other affected States)

> *[T]o develop and adopt an implementation plan that will improve the haziest days and protect the clearest days at each mandatory Class I area in the state with a goal of returning to natural visibility conditions by the year 2064. A key component of the Regional Haze Rule is the requirement to install and operate the best available retrofit technology (BART) for qualifying older, existing sources of visibility impairing pollutants.*[7]

Together Reid Gardner Units 1, 2 and 3 ("RG123") have been identified as "BART-eligible" units, meaning they must comply with the requirements of EPA's Regional Haze Rule (RG4 is not subject to the Regional Haze Rule). The original proposed State Implementation Plan ("SIP") put forth by NDEP in 2009 required the installation of pollution control equipment to reduce emission to specified levels or cease operation by January 1, 2015. The SIP is subject to approval and adoption by the Federal Environmental Protection Agency ("EPA"), and approval has been delayed. NDEP has recently indicated that it will be pushing the compliance date for the SIP to correspond with a later date specified by EPA when they announce their final approval of the rule.

The Regional Haze Rule is intended to be implemented in phases to improve visibility to natural levels by 2064 ("reasonable further progress"). The SIP is intended to satisfy the first phase of the Regional Haze Rule, and is anticipated to be followed by further actions that will lead to attaining natural visibility conditions in affected Class I areas by the year 2064. Comprehensive SIP revisions are required every ten years, with the next round of revision being due to the EPA in 2018. It is estimated that if the next SIP revision requires the installation of additional measures to achieve the State's goals, those measures will need to be in place by 2023 (within five years of the issuance of the revised SIP). This five year estimation is based on historical regulatory timing and could be modified depending on the ultimate decision of the EPA.

The EPA has confirmed that the particulate controls recently installed at RG123, and the SO2 controls currently in operation on the units meet the new BART emission requirements for SO2 and PM10. No additional capital investment will be required for these constituents. Under the current version of the Nevada SIP and based upon

[7] From http://ndep.nv.gov/baqp/planmodeling/rhaze.html - State of Nevada, Division of Environmental Protection

historical unit performance, existing NOx controls on RG123 will not meet the new BART limits. The BART determination put forth by NDEP in the SIP identifies the NOx reduction technology to be used in order to meet the proposed emission limits. The cost of complying with NDEP's and EPA's ultimate BART determinations will form the basis of a new Life Span Analysis Process ("LSAP") plan to be filed with the Commission after EPA issues its final approval of the Nevada SIP. The anticipated timing of this filing is described below.

As discussed in both written and oral comments taken during workshops in Investigative Docket 11-08019, until there is certainty on the BART compliance date, the Company cannot accurately forecast spending for BART compliance (or optional retirement of the units) for the Action Plan associated with this IRP. Once the SIP is approved, Nevada Power will perform the required engineering analysis to finalize engineering-level estimates of the cost of compliance, and perform the customary and usual analysis required by an LSAP plan. That analysis will then be presented in an appropriate resource plan or resource plan amendment filing. In conducting this review, Nevada Power will fully comply with the directives in the Commission's Interim Order from Docket Nos. 11-06007, 11-06006, and 11-06008 issued on September 9, 2011. Those directives are predicated on EPA approval of the SIP.

While full approval of the Nevada SIP is pending, Nevada Power continues to take steps to mitigate spending risks at RG123. For capital planning purposes, Nevada Power is already requiring a shorter economic justification window than the current 2020 retirement date. For purposes of this docket, no BART compliance capital was included in the Capital Expenditure Recovery ("CER") portion of the PWRR analysis. The Company will address the BART spending in a future resource plan filing once a compliance date has been finalized.

Mercury and Air Toxic Standard – "MATS" (Formerly referred to as "Utility MACT") – Reid Gardner Station

Mercury emissions are currently being monitored on Reid Gardner Unit 1. The new EPA MATS rule includes a mercury emission limitation, and review of the rule and the data from Unit 1 suggest that all four Reid Gardner Units meet the proposed limits without any incremental capital investment. Mercury emissions are controlled primarily through particulate control, with bag houses being the best option, coupled with sulfur dioxide scrubbers, the wet scrubbers being the best option. Given that all four Reid Gardner are already outfitted with the best control options, the plant has some of the lowest mercury emission levels in the country.

The EPA MATS rule allows for the use of surrogate compounds to determine compliance with emission limits for certain hazardous air pollutants. For example, a plant that is highly scrubbed with a low SO_2 emission rate would use that SO_2 rate as a surrogate for compliance with the Acid Gas limits found in the MATS rule. An initial review of the rule compared with the current emission rates indicates that Reid Gardner is well below the surrogate emission limits in the MATS rule and meets the proposed Mercury emission limit. Therefore, no capital investment at Reid Gardner will be required for compliance with MATS.

Navajo Generating Station – Regional Haze & MATS

Navajo Generating Station ("NGS") is sited on tribal lands. Therefore, the environmental regulatory body for the plant is EPA Region 9, not the State of Arizona. Thus, instead of a state-developed SIP for Regional Haze Rule compliance that is then affirmed by the EPA (as in the Reid Gardner example), at Navajo the EPA will issue a Federal Implementation Plan ("FIP") directly. In 2009, EPA indicated it was looking at a range of technology options to comply with the Regional Haze Rule, including selective catalytic reduction ("SCR") systems combined with polishing bag houses. If EPA requires the most stringent control technology under consideration, NGS owners could be required to invest over $1.1 billion (~$490/kW) for Regional Haze compliance. Nevada Power's share of NGS is 11.3%. Because of uncertainty regarding the EPA's regulatory timeline and a lack of clarity around economic assumptions (see section G below) at the time of this filing, no dollars have been included in the Action Plan for NGS Regional Haze Rule compliance.

It should be noted that combustion controls (low NOx burners) were recently installed on all three units that significantly reduced NOx emissions from the plant. It is possible that those controls could be identified by the EPA as adequate for phase 1 of Regional Haze compliance.

It is possible that any more stringent Regional Haze Rule requirements would also provide compliance with the MATS rule. The Operating Agent of the plant continues to investigate compliance options for both Regional Haze and MATS.

(G). NAVAJO GENERATING STATION UNCERTAINTY

As indicated in Figure SS-1 above, the approved retirement dates for the NGS Units 1, 2, and 3 are 2024, 2025, and 2026, respectively. However, the site lease with the Navajo Nation, and the grants of rights-of-way for the coal mine, plant, railroad, transmission and water lines, will begin expiring in 2019. Extension or replacement of each of these agreements will require multi-party negotiations and full Environmental Impact Statement ("EIS") preparation and approval. The coal supply agreement for the NGS also expires in 2019. Thus in addition to uncertainty around the extent, cost, and timing of additional investment in environmental controls, contractual issues may impact the operational life of the NGS. The operator of NGS, Salt River Project, is working diligently to resolve issues between the stakeholders, but it is important to recognize that the availability of NGS after 2019 is at risk at this time. While NPC's ownership share of the plant is relatively minor, the impacts to the energy, capacity, and natural gas markets in the Southwest could be significant if NGS retires in 2019.

Given the uncertainties described above, it is not possible at this time to perform a meaningful economic assessment of the innumerable potential environmental and contractual alternatives impacting the projected live of NGS. The Company will perform a LSAP analysis on NGS once a Regional Haze Rule determination is finalized, and timely file the LSAP in an appropriate resource plan or resource plan amendment. Should resolution of Regional Haze Rule compliance result in contractual commitments that would extend Nevada Power's obligations beyond the dates currently listed in the L&R table, the Company will seek resource planning approval of such commitments.

For more information on the history and timeline of these issues at NGS, please review http://ngspower.com/present.aspx.

(H). Generation Technologies

Nevada Power's opportunities for additional generation vary, depending on geographic, permitting and technology considerations. The fossil fired technologies modeled in this IRP include:

- Natural Gas-Fired Combined Cycle Unit: Natural gas-fired turbine technologies are evolving with respect to technical, operational, commercial, and financial characteristics. Evaluation of combustion turbine options for a combined cycle plant application identified the GE 7FA combustion turbine as a basis of cost and performance for this IRP. The 7FA has more installations than any other combustion turbine in its class with a total combined fleet operating history of over twenty million hours and an installed base of over 640 units. The performance characteristics for the 2x1 GE 7FA unit are shown in the Performance Summary for Modeling spreadsheet contained in Technical Appendix GEN-5. A typical project schedule for a 2x1 GE 7FA combined cycle plant is provided in Confidential Technical Appendix GEN-4. The Company will explore more fully the latest upgrades and technologies for a combined cycle plant to meet the resource requirements in 2018 and beyond.

- One, two or three LMS 100 Combustion Turbine Units: Combustion turbines utilized for simple cycle applications offer fast starts and high reliability. Due to the original design purpose of aero derivative engines, the LMS 100 is designed to achieve full load operation in as little as ten minutes. The performance characteristics for the LMS 100 Units are shown in the Performance Summary for Modeling spreadsheet contained in Technical Appendix GEN-5. A typical project schedule for a three block LMS 100 simple cycle plant is provided in Confidential Technical Appendix GEN-4.

- One GE 7EA Combustion Turbine Units: The GE 7EA unit is well proven in the power generation industry and offers low emissions. The size of the unit allows for reasonable additive capacity increments to satisfy peaking load requirements while the installed unit cost is similar to larger, more advanced technologies despite its reduced unit capacity. Additionally, the design of the unit avoids the utilization of advanced technology designs and materials such that operations and maintenance costs for the unit are advantageous as compared to high cycling technologies. The performance characteristics for the GE 7EA simple cycle unit are shown in the Performance Summary for Modeling spreadsheet contained in Technical Appendix GEN-5. A typical project schedule for a six block GE 7EA simple cycle plant is provided in Confidential Technical Appendix GEN-4.

As additional options, various renewable technologies were also considered for potential development. These include utility-scale wind generation, solar photovoltaic ("PV"), concentrated solar power ("CSP") with storage, and geothermal generation. While the Company has a limited history in the ownership and operation of these technologies, it is able to rely on data and information from its diverse portfolio of power purchase agreements to look at the technological attributes and benefits of such technologies for potential future generation. A counterbalancing concern is that these technologies will necessarily be geographically limited by the location of the resource. As part of the Company's review of potential sites and resources, it intends to analyze the potential use or integration of these technologies at brownfield and greenfield locations.

2. GENERATION PROJECTS WITHIN THE ACTION PLAN

(A). GENERATION SITE IDENTIFICATION – 2018-2020 TIMEFRAME

The identification and analysis of new potential generation sites must address air quality, water supply, electric transmission access, fuel availability, renewable resource potential and land use issues. These elements must be evaluated in the context of geographic, permitting and technology considerations. Due to newly proposed environmental performance standards for greenhouse gas emissions, Nevada Power is not contemplating adding new coal-fired generation at this time. The Company will also consider the ability to co-locate or integrate solar thermal, PV or other renewable energy technologies with new natural gas generation facilities.

Nevada Power's existing generation fleet is located entirely within non-attainment areas (for at least one regulated air pollutant) of Clark County, Nevada. Banked and/or purchased Emission Reduction Credits ("ERCs") would likely be required for either a new generation site (greenfield) or additions/modifications at existing generation (brownfield) sites located in Clark County. Existing generation located in Clark County may potentially be replaced using offsets from the retirement of existing generation. Building on a brownfield site is dependent on whether the emissions associated with the new generation units can fit within the banked ERCs and/or ERCs that could be obtained from retiring units. A greenfield site located outside of the Clark County non-attainment area may not require emission offsets or ERCs.

As discussed above, in compliance with the order in Docket No 10-02009, the Company retained Sargent and Lundy to complete a brownfield assessment of generation sites in Southern Nevada. The study focused on the existing sites for the Reid Gardner, Harry Allen, Silverhawk, Sunrise, Mohave and Walter M. Higgins facilities, and identified the type of development options available considering location, access, land availability, transmission constraints, water availability and environmental considerations. The report summarizes the constraints for expansion at each site and provides a high level assessment of each site for further development. The report is included as a technical appendix GEN-3 for further reference.

The Company considers a variety of selection criteria for evaluating site opportunities. These include:

- **Location**: Where is the site and what is its proximity to the load being served?

- **Land Availability**: What existing real property assets, private or public, are available? If private land is available, is the offered price comparable to that of public land? If not, does the private land offer some benefit not available from public lands, such as a shortened licensing schedule and avoidance of the National Environmental Policy Act ("NEPA") process costs?

- **Land Permitting**: Existing site, public or private, what approvals are required in order to use the site, such as zoning, planning, special use permits, etc.

- **Renewable Potential**: How does the site compare to others with respect to renewable capabilities and resource potential?

- **Air Quality**: Most of Clark County is classified as non-attainment for at least one regulated air pollutant, necessitating the utilization of the lowest achievable emissions control equipment and the use of either purchased or banked ERCs or appropriate emission offsets. Alternatively, there are areas outside of the non-attainment areas which may provide some enhanced siting potential. Other issues of concern needing assessed are new National Ambient Air Quality Standards ("NAAQS") and New Source Pollutant Standards ("NSPS").

- **Water Supply**: Water is beneficial to the efficiency of combined cycle and solar thermal facilities. Without water, dry cooling technologies can be employed, or facilities developed on simple cycle (peaking) gas turbines or PV solar installations.

- **Natural Gas Transmission**: Access to high pressure natural gas is critical to both peaking and combined cycle natural gas plants, as well as for solar thermal plants that use natural gas to maintain generating capacity during "shoulder" hours.

- **Electric Transmission**: For large scale combined cycle facilities, typically 500-600 MW in size, transmission voltage at the 345-500 kV level is preferred. Peaking and solar thermal projects within a certain size may be able to utilize lower voltage lines such as 138-230 kV.

- **Intermittent Resource Considerations**: During shoulder months as the percentage of generation from renewable resources increases, the potential to quickly load follow to offset the intermittency of these assets needs to be considered in the evaluation for new generation.

With the exception of Renewable Potential, Intermittent Resource Considerations, and New Turbine Technology criteria, the report that was completed by Sargent and Lundy includes an assessment of the above criteria for the brownfield sites located in Clark County.

The Preferred Plan in this IRP shows a need for an additional 500 MW in 2018, and an additional 2000 MW by 2020. To meet these incremental needs the Company recommends that the Commission authorize the completion of the following recommendations.

Recommendation 1: a comprehensive study and conceptual design for a Company-owned brownfield facility, suitable for commercial operation as early as 2018. This study is the next step for the work authorized in the 2009 IRP where Nevada Power performed its preliminary assessment. While the 2018 expansion resources are identified in this IRP as peaking units, this study will also assess combined cycle options in order to preserve maximum flexibility at this stage in the planning process. This study and conceptual design will build upon the prior studies performed, and is estimated to cost $3.5 million dollars.

Begins with a Site Screening Level Analysis of a brownfield site: The Company will engage the services of an experienced architectural and engineering firm to refine the preliminary work performed in 2011 and 2012, including:

- New Gas Combustion Turbine Technology;
- Natural gas supply pipeline capacity and risk;
- Electrical power interconnect and transmission risk;
- Environmental / Permitting requirements and risk;
- Determination of New Source Review ("NSR") requirements including developing emission values for project emission sources and offsets from retirement of existing unit(s). This includes the consideration of banked or traded ERCs. The emission point estimates and location information suitable to support air dispersion modeling will also be determined and provided, if required, for the project;
- Greenhouse Gases ("GHG") permitting and BACT requirements;
- Assessment of NAAQS concerns;
- Pre- and post-construction ambient monitoring requirements (if required);
- Drafting and submitting required NEPA studies and/or NSR permit applications;
- Water supply/discharge availability and requirements;
- Site topography and geotech characterization;
- Property considerations;
- Renewable generation potential; and,
- Demolition studies (if necessary).

- Re-use of existing infrastructure.

Perform conceptual plant design:

- Perform preliminary evaluations of technology options, predicted plant performance, etc. These evaluations would be documented in a preliminary design basis document which would be used as input to the preparation of equipment and EPC specifications. The preliminary evaluations would include:
  - Comparison of gas combustion turbine technologies (F class, G class, and H class);
  - Heat balance calculations to determine optimal plant configuration (Peakers, 1x1, 2x1, and 3x1) and HRSG types;
  - Plant System Design:
    - CTG technology
    - Steam cycle parameters
    - Feedwater system design
    - Deaeration
    - Water balances and means to preserve fresh water

- Plant operating flexibility with respect to plant dispatch (base load or intermediate) expectations. This analysis would include a review of the benefits and complications associated with fast start plant designs as compared to traditional start designs;
- Potential for renewable generation and/or integration;
- Emissions:
  - Emission controls: Identification of the SCR and CO catalyst designs required to satisfy the emissions limitations. Compliance with GHG, BACT requirements, and NAAQS.
  - Fuel gas condition requirements/fuel specification requirements
  - Site specific design criteria and interface conditions
  - Electrical interconnection analysis support
  - Review and possible integration of existing plant systems into new generation

All of the above issues will be summarized in a preliminary project feasibility and design basis document. The design basis document would include:

- Design basis discussion including:
  - Overall Plant Configuration
  - Thermal Cycle Design
  - Major Equipment Ratings and Design Margins
  - Fuel Specifications
  - Site and Plant Arrangement (including drawings)
  - Air Emissions

  - Site-Specific Design Criteria
  - Water Systems Overview
  - Electrical Interconnection
  - Communications
  - Codes and Standards
- Mechanical Systems and Equipment Requirements
- Electrical Systems and Equipment Requirements
- Instrumentation and Control System Requirements
- Civil/Structural/Architectural Features
- Permitting Matrix and permit submission
- Drawings included in the Design Basis Document would include:
  - Heat balance diagrams
  - Water balance diagrams
  - Site Layout drawings
  - One-Line diagrams
  - Control system architecture drawing

Develop project schedule and cost estimate:

- Develop a Level 1 project schedule taking into account current market lead times for major equipment (steam turbine generator, combustion turbine generators, heat recovery steam generator, generator step-up transformer, solar panels).
- Develop a project cost estimate for the engineering, equipment, materials, and construction labor costs (estimate will include a recommended contingency) for the new combined cycle plant. The project cost estimate would be developed by soliciting budgetary quotes from equipment manufacturers and using database quantities for bulk materials and construction labor hours. The estimate will be suitable for project planning activities and would support a request to the Commission for project approval.

Develop technical procurement specification for a steam turbine generator and issue RFP:

- It is anticipated that a steam turbine generator will be the component with the longest lead time, and the procurement of this item will be critical in determining the project schedule and ultimately the commercial operation date for the project. This scope would be to develop a technical procurement specification for the steam turbine generator such that it was ready for release shortly after project approval by the Commission.

<u>Recommendation 2:</u> a Site Screening Level study for a new greenfield site suitable for commercial operation beginning in 2020 is estimated to cost of $5.0 million dollars, and is described in more detail below.

Site Screening Phase Assessment of potential greenfield Sites: The Company will engage the services of an experienced architectural and engineering firm to assess the viability of siting additional Greenfield generation outside of the non-attainment area of Clark County, Nevada. This screening study would expand the format of the Comparative Site Analysis performed by Sargent and Lundy in May 2012. The assessment will address issues such as air quality, water, ecological and geophysical issues, socioeconomics, infrastructure, fuel diversity and renewable potential. Cost, including internal review and management, is estimated at $5,000,000. It is estimated that the site screening study can be completed within approximately twenty-four months. This work is necessary to meet the needs highlighted in the IRP for 2020 and beyond.

- Prequalification Phase: Based on the results of the site screening study, two to three geographic locations will be selected for further detailed study, including identification of potential sites, air impact modeling, natural resource impacts, socioeconomic and cultural assessments, water availability, land use assessment (permitted uses), renewable resource potential and fuel delivery and transmission system impact assessments. Each of these prequalification estimates would cost an estimated $250,000 per site, or as much as $750,000 total. The duration of the prequalification analysis is estimated at 8 months.

- Assuming one or more suitable site candidates is identified as a result of the prequalification analysis, the Company will proceed with securing a site through an option agreement, commence land use applications (such as an Environmental Assessment ("EA") or Environmental Impact Statement ("EIS") in the event the site is on federal lands), establish a meteorological monitoring station and submit an air permit application. The Company estimates the costs to complete these activities per site to be approximately $4.25 million, and take approximately eighteen months to complete. The Company will return to the Commission for approval to construct on a permitted site before major material orders have been placed.

<u>Recommendation 3:</u> Renewable Additions at Existing Generating Facilities. The Company would undertake permitting activities to facilitate the addition of renewable technologies, primarily solar, at or near the Company's existing generating sites. The Company would primarily undertake BLM permitting efforts to accommodate the maximum flexibility for the Company to co-locate renewable technologies at or near existing generator sites, including without limitation the Harry Allen and Chuck Lenzie facilities. The Company will engage the services of one or more experienced environmental and/or technical service firms to undertake preliminary analysis and design of potential renewable facilities and carry out the permitting activities on behalf of the Company with BLM or other regulatory bodies in order to maintain the Company's ability to construct renewable facilities at such sites. The assessment and permitting will address issues such as resource adequacy, ecological and geophysical issues, socioeconomics, infrastructure, fuel diversity and any other issues necessary to complete NEPA permitting with BLM of renewable facilities at such sites. Cost for preliminary permitting, including internal review and management, is estimated at $1,450,000. The permitting activity will require NEPA review and is estimated to require at least two years. This work is necessary to meet the needs highlighted in the IRP for 2018 and beyond if the Company were to pursue renewable options as part of a diverse generation portfolio to meet customer load.

B. POWER PURCHASE & PORTFOLIO ENERGY CREDIT AGREEMENTS

Nevada Power meets the energy demands of its customers through a combination of Company-owned generating units and power purchase agreements ("PPAs"). The PPAs vary by fuel type (natural gas, geothermal, etc.), contract type (dispatchable, must take), and contract length (short-term, long-term, seasonal). In additional to PPAs for puchased power from conventional resources and cogeneration facilities, Nevada Power meets the requirements of the State of Nevada's RPS through a combination of renewable energy PPAs, PC only agreements, and energy efficiency programs (see Section 2.B.3.). Figures SS-2, SS-3, and SS-4 below list all of Nevada Power's conventional, qualifying facility and renewable PPAs.

FIGURE SS-2 - CONVENTIONAL POWER PURCHASE AGREEMENTS

CONVENTIONAL ENERGY PPAs/POWER EXCHANGE AGREEMENT (DISPATCHABLE)

Counterparty	Project	Location	Fuel Type	Contract Type	MW	Contract Start Date	Contract End Date
ArcLight Capital Partners, LLC	Nevada Sun-Peak Limited Partnership	Las Vegas, NV	Gas	Tolling-Capacity & Energy	222.0	06/01/91	05/31/16
Colorado River Commission	Hoover	Boulder City, NV	Hydro	Capacity & Energy	235.0	01/01/87	09/30/17
Star West Generation LLC	Griffith Energy LLC	Kingman, AZ	Gas	Tolling-Summer Only, Capacity & Energy	570.0	06/01/08	09/30/17
Southwest Generation Operating Company, LLC	Las Vegas Cogen I	North Las Vegas, NV	Gas	Tolling-Summer Only, Capacity & Energy	50.0	06/01/08	09/30/17
Southwest Generation Operating Company, LLC	Las Vegas Cogen II	North Las Vegas, NV	Gas	Tolling-Capacity & Energy	224.0	04/01/04	12/31/13
Southern Nevada Water Authority	Power Exchange Agreement	Apex, NV	Gas	Tolling-Capacity & Energy (Silverhawk)	130.0	06/01/05	05/31/13
				Firm Sale	(75.0)		
				Total	1,356.0		

FIGURE SS-3 – QUALIFYING FACILITY PURCHASE POWER AGREEMENTS (MUST TAKE)

QUALIFYING FACILITY PPAs (MUST TAKE)

Counterparty	Project	Location	Fuel Type	Contract Type	MW	Contract Start Date	Contract End Date
Nevada Cogeneration Associates #1	NCA#1	Las Vegas, NV	Gas	Capacity & Energy	85.0	06/18/92	04/30/23
Nevada Cogeneration Associates #2	NCA#2	Las Vegas, NV	Gas	Capacity & Energy	85.0	02/01/93	04/30/23
Saguaro Power Company	Saguaro	Henderson, NV	Gas	Capacity & Energy	90.0	10/17/91	04/30/22
				Total	260.0		

FIGURE SS-4- RENEWABLE POWER PURCHASE AGREEMENTS

RENEWABLE ENERGY PPAs

Counterparty	Project	NV Location	Fuel Type	Contract Type	MW	Contract Start Date	Contract End Date
Acciona-Solargenix, LLC	Nevada Solar One [a.]	Boulder City	Solar Thermal	Capacity & Energy	56.6	06/27/07	12/31/27
American Capital Energy	Searchlight Solar [c.]	Clark County	Solar	Capacity & Energy	17.5	Q4/2012	12/31/32
CC Landfill Energy, LLC	CC Landfill Energy [c.]	Clark County	Landfill Gas	Capacity & Energy	12.0	Q1/2012	12/31/32
Enel Salt Wells, LLC	Salt Wells [b.]	Churchill County	Geothermal	Capacity & Energy	23.6	09/18/09	12/31/29
Enel Stillwater, LLC	Stillwater II [b.]	Churchill County	Geothermal	Capacity & Energy	47.2	10/10/09	12/31/29
Enel Stillwater, LLC	Stillwater II PV [b.& c.]	Churchill County	Solar PV	Capacity & Energy	22.0	Q1/2012	12/31/29
Fotowatio Nevada Solar, LLC	RV Apex Solar Power [c.]	Clark County	Solar PV	Capacity & Energy	20.0	Q2/2012	12/31/37
FRV Spectrum Solar LLC	FRV Spectrum Solar [c.]	Clark County	Solar PV	Capacity & Energy	30.0	Q3/2013	12/31/38
Mountain View Solar, LLC	Mountain View Solar [c.]	Clark County	Solar PV	Capacity & Energy	20.0	Q1/2014	12/31/39
Nevada Geothermal Power	Faulkner 1 [b.]	Humboldt County	Geothermal	Capacity & Energy	49.5	11/20/09	12/31/29
Ormat Nevada / ORNI 3	Desert Peak 2 [b.]	Churchill County	Geothermal	Capacity & Energy	25.0	04/17/07	12/31/27
Ormat Nevada / ORNI 9	Galena 2 [b.]	Washoe County	Geothermal	Capacity & Energy	13.0	05/02/07	12/31/27
Ormat Nevada / ORNI 15	Jersey Valley [b.]	Lander County	Geothermal	Capacity & Energy	22.5	08/30/11	12/31/31
Ormat Nevada / ORNI 32	Dixie Meadows [c.]	Churchill County	Geothermal	Capacity & Energy	51.0	Q2/2015	12/31/35
Ormat Nevada / ORNI 39	McGinness Hills [b.& c.]	Lander County	Geothermal	Capacity & Energy	52.0	Q2/2012	12/31/32
Ormat Nevada / ORNI 42	Tuscarora [b., c. & e.]	Elko County	Geothermal	Capacity & Energy	25.0	Q1/2012	12/31/31
Ormat Nevada / ORNI 42	Tuscarora, (Exp. Option) [c..]	Elko County	Geothermal	Capacity & Energy	25.0	Q1/2017	12/31/31
Ram Power	Clayton Valley [c.]	Esmeralda County	Geothermal	Capacity & Energy	53.5	Q3/2014	12/31/34
Silver State Solar, LLC	Silver State Solar [c.]	Clark County	Solar PV	Capacity & Energy	52.0	Q2/2012	12/31/37
SolarReserve LLC	Crescent Dunes [c.]	Nye County	Solar Thermal	Capacity & Energy	110.0	Q4/2013	12/31/38
Spring Valley Wind, LLC	Spring Valley Wind [b.& c.]	White Pine County	Wind	Capacity & Energy	151.8	Q2/2012	12/31/32
WM Renewable Energy, LLC	Lockwood [b.& c.]	Storey County	Landfill Gas	Capacity & Energy	3.2	Q1/2012	12/31/32
				Total	882.4		

RENEWABLE ENERGY RELATED PPAs

Counterparty	Project	NV Location	Fuel Type	Contract Type	MW	Contract Start Date	Contract End Date
Sierra Pacific Power Company	Nevada Solar One [a.]		Solar Thermal	Capacity & Energy	12.4	06/27/07	12/31/27
Sierra Pacific Power Company	Salt Wells [b.]	Churchill County	Geothermal	Capacity & Energy	(23.6)	09/18/09	12/31/29
Sierra Pacific Power Company	Stillwater II [b.]	Churchill County	Geothermal	Capacity & Energy	(47.2)	10/10/09	12/31/29
Sierra Pacific Power Company	Stillwater II PV [b.& c.]	Churchill County	Solar PV	Capacity & Energy	(22.0)	Q1/2012	12/31/29
Sierra Pacific Power Company	Faulkner 1 [b.]	Humboldt County	Geothermal	Capacity & Energy	(49.5)	11/20/09	12/31/29
Sierra Pacific Power Company	Desert Peak 2 [b.]	Churchill County	Geothermal	Capacity & Energy	(25.0)	04/17/07	12/31/27
Sierra Pacific Power Company	Galena 2 [b.]	Washoe County	Geothermal	Capacity & Energy	(13.0)	05/02/07	12/31/27
Sierra Pacific Power Company	Jersey Valley [b.]	Lander County	Geothermal	Capacity & Energy	(22.5)	08/30/11	12/31/31
Sierra Pacific Power Company	McGinness Hills [b.& c.]	Lander County	Geothermal	Capacity & Energy	(52.0)	Q2/2012	12/31/32
Sierra Pacific Power Company	Tuscarora [b.& c.]	Elko County	Geothermal	Capacity & Energy	(25.0)	Q1/2012	12/31/31
Sierra Pacific Power Company	Spring Valley Wind [b.& c.]	White Pine County	Wind	Capacity & Energy	(151.8)	Q2/2012	12/31/32
Sierra Pacific Power Company	Lockwood [b.& c.]	Storey County	Landfill Gas	Capacity & Energy	(3.2)	Q1/2012	12/31/32
				Total	(422.4)		

GRAND TOTAL LONG-TERM RENEWABLE POWER PURCHASE AGREEMENTS **460.0**

RENEWABLE PC ONLY AGREEMENTS

Counterparty	Project	NV Location	Fuel Type	Contract Type	MW	Contract Start Date	Contract End Date
MMA Renewable Ventures	SolarStar, NAFB	Las Vegas	Solar PV	PC Only	13.2	12/15/07	12/31/27
Steamboat Geothermal	Steamboat 1A SU	Washoe County	Geothermal	PC Only	2.0	01/01/04	12/31/13
SunPower	LVWD (Six sites)	Las Vegas	Solar PV	PC Only	3.0	04/20/06	12/31/26
Sierra Pacific (NPC buys from SPPC)	Various Ormat Geothermal	SPPC's Service Territory	Geothermal	PC Only	d.	01/01/09	12/31/28
Amonix	Pecos [c.]	Clark County	Solar PV	PC Only	0.5	Q4/2012	12/31/17
Amonix	CNLV Water Reclamation [c.]	Clark County	Solar PV	PC Only	1.0	Q4/2012	12/31/32
				Total	19.7		

Notes:

a. Both NPC & SPPC have PPAs with Nevada Solar One. Currently, because the generator is electrically interconnected to NPC's system, SPPC resells the energy to NPC under a RPPA.

b. These units are or initially will be electrically interconnected to SPPC's system. NPC will resell the energy to SPPC under RPPAs pending the completion of the ON Line north/south intertie.

c. Units have not declared commercial operation or have declared commercial operation but that declaration has not been confirmed by the utility at the time this filing was being prepared. The start date listed (quarter & year) and termination dates (always the last day of the year) are estimates per the data available as of February 1, 2012

d. The number and price of renewable energy credits sold to NPC by SPPC is based on a predetermined schedule: (2012) 60,200 kPCs, (2014) 51,361 kPCs & (2015-2028) 19,710 kPCs. 1 kPC= 1,000 PCs. Reference Commission Order Docket Nos. 09-09018 (SPPC) & 09-08020 (NPC)

e. 25 MW capacity reflects contractual limitation pre-expansion and not actual nameplate installation.

A brief overview of these Agreements follows:

1. CONVENTIONAL ENERGY PPAS

Nevada Power has five long-term dispatchable PPAs for conventional energy and a power exchange agreement with SNWA for a total capacity of 1,356 MW. In the power exchange agreement, Nevada Power receives the rights to SNWA's 25% interest in the Silverhawk Power Plant (130 MW), in exchange for which Nevada Power provides SNWA with 75 MW of firm energy delivered to the Mead Substation. The power exchange agreement expires May 31, 2013. The Action Plan includes a request for approval of a new power exchange agreement with SNWA, effective June 1, 2013, as described in Section 5.A below.

2. QUALIFYING FACILITY PPAS

Pursuant to the Public Utility Regulatory Policies Act ("PURPA"), Nevada Power has three long-term PPAs with gas-fired Qualifying Facilities ("QFs") with a total capacity of 260 MW. All three agreements are with cogeneration plants that use natural gas as the primary fuel for generation of electricity and utilize waste heat from the electric generator for industrial purposes. These PPAs are for energy only—the waste heat technology utilized by these plants do not qualify for PECs under Nevada's RPS.

3. RENEWABLE ENERGY & RELATED PPAS[8]

Nevada Power has executed and the Commission has approved a total of twenty long-term renewable energy PPAs representing a total capacity of 882.4 MW, of which 296.4 MW were in-service as of Q1 2012. Already approved projects representing 586 MW are scheduled to be completed between Q2 2012 and Q1 2017. Two of the largest projects in the development pipeline are Spring Valley Wind (151.8 MW) and Crescent Dunes (110.0 MW). Spring Valley will be Nevada's first large scale wind project. The Crescent Dunes project is on track to be the first large scale solar thermal facility in the United States utilizing a central receiver tower design with molten salt storage technology. Since Nevada Power's previous IRP filing, three new PPAs (FRV Spectrum Solar, Mountain View Solar, & Dixie Meadows Geothermal) and one PPA amendment to expand an existing facility (Stillwater 2 PV) have been approved by the Commission. Offsetting these three new contracts and one amendment were two contract terminations. The Carson Lake Basin and Carson Lake contracts were terminated due to the counterparties' inability to achieve commercial operation at contracted production levels.

Until the completion of the ON Line project, Nevada Power will continue to resell the geothermal and wind energy that is connected to Sierra's system but under contract with Nevada Power back to Sierra, while retaining the Renewable Portfolio Credits ("PCs") from these projects for use towards its compliance with Nevada's RPS. Similarly, Sierra will resell its contractual share of the energy from the Nevada Solar One project, which is

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8 Please refer to Technical Appendix REN-1 for the anticipated costs for each of the long-term renewable energy agreements.

physically interconnected to Nevada Power's system, back to Nevada Power while retaining the PCs from the project for use towards its compliance with Nevada's RPS. These transactions will continue to be governed by Commission-approved Related PPAs.

4. SHORT-TERM RFP CONTRACTS

Based on its forecasted credit requirement and supply outlook, Nevada Power does not contemplate a need for deliveries from any short-term renewable contracts (energy and credits or credit only) in order to achieve RPS compliance during the upcoming Action Plan period (2013-2015). However, Nevada Power will diligently monitor its portfolio and any external changes (such as change in load or law) that may cause it to revisit this requirement.

5. SECOND POWER EXCHANGE AGREEMENT WITH SNWA

In 2005, as part of the Business Accord Master Agreement ("Business Accord") between Nevada Power, the Southern Nevada Water Authority ("SNWA"), and the Colorado River Commission of Nevada ("CRC"), Nevada Power and the SNWA executed a Power Exchange Agreement ("Existing Power Exchange"). The Existing Power Exchange was effective June 1, 2005, and expires May 31, 2013. Nevada Power and SNWA have executed a Second Power Exchange Agreement ("Second Power Exchange"), for which the Company requests Commission approval in this IRP filing. The Second Power Exchange is attached as Technical Appendix CON-2 in this filing.

(A). EXISTING POWER EXCHANGE

The term of the Existing Power Exchange is June 1, 2005, through May 31, 2013. The Existing Power Exchange provides Nevada Power the right to dispatch SNWA's 25% share of the Silverhawk plant (130 MW in the summer months, 150 MW in the non-summer months). When Nevada Power utilizes SNWA's share of Silverhawk under the Existing Power Exchange, Nevada Power is responsible for providing the natural gas necessary to generate the required energy, and also pays the variable O&M rate associated with the Silverhawk plant.

In exchange for this right, Nevada Power delivers 75 MW of firm energy to SNWA (7 days per week, 24 hours per day) at the Mead 230 kV substation. SNWA pays Nevada Power for such energy at the rate of 7.2 MMBtu/MWh times the SoCal Border natural daily gas index price, plus the Silverhawk variable O&M rate.

In addition, under the Existing Power Exchange SNWA provides Nevada Power with the exclusive right to utilize SNWA's 125 MW point-to-point transmission contract from the Harry Allen switchyard to the Mead 230 kV substation. Nevada Power pays all costs of the SNWA 125 MW transmission contract.

The Business Accord (which also resolved litigation between the parties), the Existing Power Exchange, and two other ancillary agreements were approved by the Commission in Docket Nos. 05-4014 and 05-4015. In Docket 05-4014, Nevada Power filed Rate Schedule RPE (Retail Power Exchange), which was also approved by the Commission.

(B). SECOND POWER EXCHANGE

The term of the Second Power Exchange is June 1, 2013, through December 31, 2018. As with the Existing Power Exchange, the Second Power Exchange will provide Nevada Power the right to dispatch SNWA's 25% share of the Silverhawk plant. When Nevada Power utilizes SNWA's share of Silverhawk under the Second Power Exchange, Nevada Power will once again be responsible for providing the natural gas necessary and will also pay the variable O&M rate associated with the Silverhawk plant.

In the Second Power Exchange, Nevada Power will deliver to SNWA at the Mead 230 kV substation, 125 MW of firm energy during on-peak hours (7x16) and 25 MW of firm energy during off-peak hours (7x8). SNWA will pay Nevada Power for such energy at rate of 7.5 MMBtu/MWh times the SoCal Border natural daily gas index price, plus the Silverhawk variable O&M rate.

As with the Existing Power Exchange, under the Second Power Exchange, SNWA will provide Nevada Power with the exclusive right to utilize SNWA's 125 MW point-to-point transmission contract from the Harry Allen switchyard to the Mead 230 kV substation. However, under the Second Power Exchange SNWA will pay all costs of the transmission contract.

The Second Power Exchange includes a provision that would allow either party to terminate the agreement if a greenhouse gas tax, charge, or fee is enacted on Nevada Power's use of SNWA's share of Silverhawk, or any other resource used by Nevada Power to make the deliveries to SNWA required in the Second Power Exchange.

Coincident with this IRP Filing, Nevada Power is filing a modification to Rate Schedule RPE to reduce the required term of a retail power exchange permitted under that schedule from seven (7) to five (5) years.

Nevada Power requests a Commission determination that (1) the terms and conditions of this Second Power Exchange are just and reasonable, (2) the costs associated with the Second Power Exchange are prudently incurred and that Nevada Power may recover all just and reasonable costs associated with the Second Power Exchange, and (3) the Second Power Exchange qualifies as a retail power exchange under Nevada Power Rate Schedule RPE. Either party may terminate the Second Power Exchange if the Commission does not approve the agreement by December 31, 2012, or if the Commission approves the agreement with conditions that are unacceptable to either party.

(C). ECONOMICS OF THE SECOND POWER EXCHANGE

An economic analysis showing the benefit of the Second Power Exchange is provided in Technical Appendix ECON-27.

6. QUALIFYING FACILITIES (QFS) RFP

In Nevada Power's 2010-2029 resource plan (Docket 10-02009), the Company presented its projected long-term avoided costs (see Volume 17, Section 3.J). The Company proposed to use a competitive bidding solicitation process for up to 25 MW to determine which, if any, contracts the Company should enter into, using long-term avoided costs as the cap.

On December 6, 2011, Nevada Power let a Request for Proposal ("RFP") to purchase up to 25 MW from QFs located in Nevada Power's service area. The RFP was sent to over 200 parties. Sierra issued a similar RFP on the same day.

Nevada Power received eight (8) proposals in response to the December 6, 2011 RFP. Four (4) of the proposals offered development rights and/or joint venture ownership but did not offer to sell power to Nevada Power under a purchase power agreement. One proposal was not located in Nevada. One proposal was located in Sierra's service area and was considered under Sierra's RFP. One proposal offered capacity that was already covered under an existing QF agreement with the Company. Finally, one proposal offered capacity that is currently under contract with the Company, but would not be available as a QF until 2018, and the exceeded the 25 MW cap. In summary, none of the proposals conformed to the RFP, and, as such, Nevada Power did not pursue any of the proposals.

C. FUEL CONTRACTS

1. CURRENT PHYSICAL GAS SUPPLY AGREEMENTS

Nevada Power is connected directly through interstate pipeline systems with several major gas producing regions including the Permian, San Juan, Anadarko, and the Rocky Mountain supply basins, as well as California gas supply. The largest producing region with the best connectivity into and through Nevada Power's control area is the Rocky Mountain supply basin. As discussed further in Section II. B of the Load Forecast and Market Fundamentals volume, this gas supply basin is considered by some experts to be a proven supply that is expected to increase through the year 2030. The Kern River Pipeline ("Kern River") connects the Rocky Mountain basin through Nevada into Southern California with a firm capacity of 1.9BCF/day; however 2011 annual throughput (firm plus interruptible) averaged about 2.2 BCF / day. This pipeline deliverability capacity is large in comparison to Nevada Power's daily needs. By way of comparison, Nevada Power's 2013 estimated daily gas supply requirements for its entire Clark County generating fleet (including gas tolling agreements for LV Cogen 1 and 2) range from a winter peak season requirement of approximately 270,000 MMBtu / day, to a summer peak season requirement of slightly above 500,000 MMBtu / day. Figure SS-5 lists Nevada Power's existing gas transportation service agreements.

Gas supplies for Nevada Power's Harry Allen, Chuck Lenzie, Higgins, Silverhawk, and Reid Gardner plants are delivered directly by Kern River. Nevada Power currently holds contracts for firm forward haul gas transportation rights on Kern River totalling 424,925 MMBtu / day (summer) and 374,925 MMBtu / day (winter) to serve a majority of its overall daily natural gas needs. Nevada Power has rollover rights under the Kern River tariff, provided Nevada Power is willing to continue under the terms and conditions specified therein. Nevada Power has a long-term agreement with Kern River for back haul capacity of 134,000 MMBtu /day.

The Clark and remaining Sunrise peaking facilities (Sunpeak) receive gas delivered under a 288,000 MMBtu / day transportation service contract with Southwest Gas ("SWG"). The transportation agreement with SWG provides for receipt of Kern River supplies, as well as limited quantities of gas from sellers off of the El Paso and/or Transwestern pipelines south of Las Vegas (from the Topock, Arizona area, if SWG is not using its capacity rights to serve their own requirements). The maximum capacity of SWG's connection with these southern interstate pipelines is estimated at about 170,000 MMBtu / day. Topock-delivered gas is sourced upstream from the San Juan Basin and Permian Basin supply regions.

Nevada Power also purchases gas supply for delivery through the SWG system to satisfy a tolling agreement with LVC2, with a separate firm transportation contract for up to 45,000 MMBtu / day that is in effect until 2013. The Company also can procure Topock-sourced gas for re-delivery into Kern River at Daggett, California.

The Dynegy Griffith Plant is physically located off of El Paso and Transwestern Pipelines in northwest Arizona, and is served directly by those pipelines.

FIGURE SS-5 - GAS TRANSPORTATION SERVICE AGREEMENTS ("TSA")

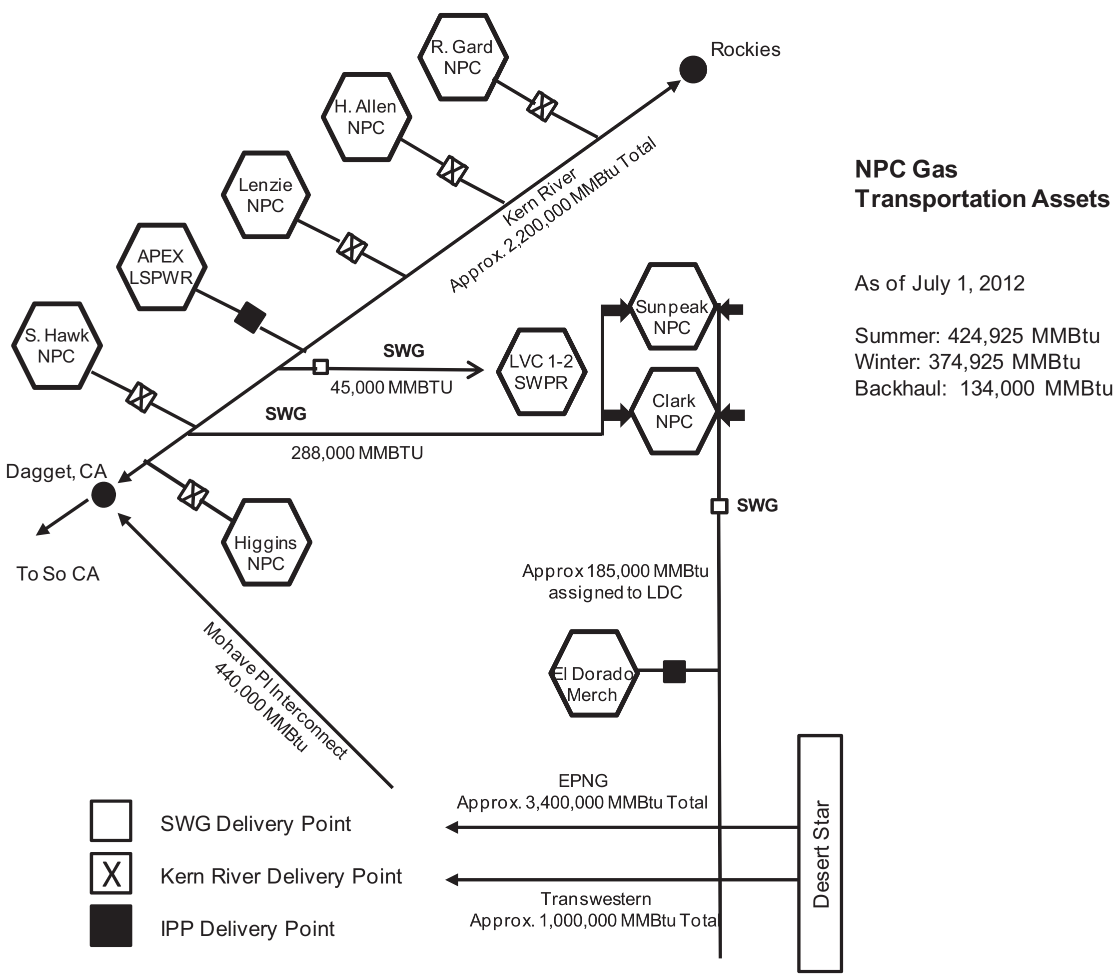
				Maximum Daily Quantity (MMBTUs)				
Contract Type	Counterparty	Contract #	Termination Date	Annual	Winter	Summer I (May-Oct)	Summer II (Apr-Oct)	Comments
TSA	Kern River	1707	4/30/2018	75,000				
TSA	Kern River	1720	4/30/2018				50,000	
TSA	Kern River	7649	4/30/2018	12,500				
TSA	Kern River	7668	9/30/2016	11,075				
TSA	Kern River	7667	9/30/2016	10,350				
TSA	Kern River	1617-2	10/31/2031	134,000				Backhaul
TSA	Kern River	1830	10/31/2031	266,000				Forward Haul
Rental	Kern River	Higgins Facility Meters	12/31/2017					No Volume
TSA	SW Gas[1]	21016	4/30/2027	288,000				
TSA	SW Gas[1]	21011	9/30/2017		5,200			(LVC 1)
TSA	SW Gas[1]	21088	12/31/2013	45,000				(LVC 2)

[1] This contract is not with NPC, but is being shown for informational purposes only

Nevada Power's open position with respect to firm interstate gas transportation is very small and can be reliably met by purchasing firm delivered gas. Figure SS-6 shows the pipeline routes.

FIGURE SS-6 - PIPELINE ROUTES

NPC GAS DIAGRAM



Nevada Power's proposed gas transportation strategy for the Action Plan period is set forth in Section 1 of Nevada Power's 2012 Energy Supply Plan.

2. PHYSICAL GAS PROCUREMENT

In Docket No. 09-07003 the Commission approved a four-season laddering strategy for physical gas purchases through which Nevada Power would procure 25% of projected monthly gas requirements per season, subject to the availability of conforming bids and the willingness of suppliers to accept reasonable commercial terms. Physical gas volumes were to be procured at indexed prices, subject to a cap of $0.025 per MMBTU on the premium. The $0.025 per MMBTU cap could be exceeded with prior approval from the Energy Risk Committee. However, if the $0.025 per MMBTU premium cap was exceeded, Nevada Power would provide written notice to the Staff and Bureau of Consumer Protection indicating such. As is described in the Energy Supply Plan, Nevada Power is proposing to continue to follow the physical gas procurement strategy reviewed and approved in Docket No. 09-07003.

During Q3 of 2012, Nevada Power will issue a Request for Proposal for physical gas supply for the period November 2012 through October 2014 as part of the four season laddering strategy. Figure SS-7 reflects the planned implementation of the physical gas acquisition strategy.

FIGURE SS-7 - PHYSICAL GAS ACQUISITION STRATEGY

	Delivery						
Transaction	Winter '12-'13	Summer '13	Winter '14-'15	Summer '14	Winter '15-'16	Summer '15	Winter '16-'17
Q3 '12	100%	75%	50%	25%			
Q1 '13		25%	25%	25%	25%		
Q3 '13			25%	25%	25%	25%	
Q1 '14				25%	25%	25%	25%
Q3 '14					25%	25%	25%
Q1 '15						25%	25%
Q3 '15							25%
Sum	100%	100%	100%	100%	100%	100%	100%

Note: Winter includes the months of Nov through Mar and Summer includes the months of Apr through Oct.

All of Nevada Power's physical gas is expected to come from the Rocky Mountain gas supply basin. Nevada Power's proposed strategy for procuring physical gas supplies during the Action Plan period is provided in the 2012 Energy Supply Plan.

3. CURRENT OIL SUPPLY AGREEMENTS

Nevada Power does not currently use fuel oil as a secondary fuel at any of its generating sites or for start-up fuel for Reid Gardner. However, Nevada Power is contractually obligated to supply fuel to the remaining Sunpeak units at Sunrise Station, which are capable of #2 diesel firing. At Nevada Power's discretion, the Sunpeak generators can be dispatched on #2 diesel fuel. If the Company dispatches Sunpeak on #2 diesel fuel, it is obligated to procure and deliver the fuel. Given the low probability of #2 diesel fuel firing at Sunpeak, Nevada Power is not proposing to maintain long term oil supply contracts during the Action Plan period, relying instead on the purchase of delivered product only as needed.

4. CURRENT COAL PURCHASE &TRANSPORTATION AGREEMENTS

Coal delivered to the Reid Gardner Station originates from mines in Utah, Colorado, and Wyoming and is delivered to the station via the Union Pacific Railroad.

Nevada Power currently has three separate coal supply agreements that run through 2012 or 2013. The Coal Supply Agreement with Andalex Resources, Inc., is for coal from their West Ridge Mine in central Utah and extends through 2012. Coal delivered under this contract can be burned at any of the Reid Gardner Units. The Coal Supply Agreement with Thunder Basin Coal Company, an affiliate of Arch Coal Sales Company originally provided coal from their Black Thunder Mine in the Southern Power River Basin, Wyoming, through Q1 2012. In April 2012, this Agreement was amended to convert the source mine to Arch's Sufco Mine in Central Utah. The amendment resulted in a lower delivered cost for Sufco coal and extends through 2013. Coal supplied under this agreement can be burned in Units 1, 2, and 3.The Coal Supply Agreement with Canyon Fuels is for coal from the Sufco and Skyline Mines in Central Utah, and the West Elk Mine in Western Colorado. This agreement provides coal to Unit 4 and extends through 2013.

The Union Pacific Rail Transportation Services Agreement, which expires at the end of 2014, provides for deliveries from Central Utah, Western Colorado, Southern Wyoming, and the Powder River Basin ("PRB"). Nevada Power leases 205 aluminum rapid discharge coal cars and Union Pacific provides up to 16 cars per train (for a total of two trains plus spares) that deliver Reid Gardners coal. Nevada Power's leases are with Flagship Rail Services, LLC, for 179 cars and Mitsui Rail Capital, LLC, for 26 cars and extend through December 2014 and June 2013, respectively.

Navajo Generating Station receives 100 percent of its coal requirements from the Kayenta Mine on the Navajo and Hopi reservations in the Black Mesa Basin of Arizona, under a long-term Coal Supply Agreement with Peabody Western Coal Company. The contract for Navajo coal terminates at the end of 2019. Navajo coal is transported 78 miles from the Kayenta Mineto the Navajo Stationvia a private railroad.

D. RENEWABLE ENERGY PLAN

1. OVERVIEW

Nevada Power has seen significantly greater success in its renewable energy portfolio over the last three years, experiencing a success rate of nearly ninety percent for renewable projects contracted with since 2009. This is very different from the previous experience of fifty to sixty percent success rates in the early years of the Renewable Portfolio Standard ("RPS"). Beginning in 2010, Nevada Power met the overall RPS for the first time without borrowing from its sister utility, Sierra, and Nevada Power expects to meet the RPS requirement of fifteen percent in 2012.

Initially, the RPS only required that one percent (1%) of a utility's total retail electric consumption come from renewable energy. That has grown significantly to the current fifteen percent RPS requirement, which will grow to twenty-five percent by 2025, with five percent (5%) of the RPS that must be generated or acquired from solar resources (growing to six percent (6%) starting in 2016). The RPS continues to grow in accordance with statutory requirements, even during periods of flat load growth. The ability to comply with the RPS after 2020 will be dependent on a multitude of variables that will evolve over time, such as load, changes in law, continued successful operation of the existing portfolio and stable resource for projects. Compliance with the RPS requires the Company to measure against a continuously evolving target.

Nevada Power's successful acquisition and management of its renewable portfolio is expected to enable the Company to comply with the RPS through at least 2020 (based on current law and load projections). Many factors have contributed to Nevada Power's success over the last three years, including the Commission's approval of several large-scale renewable projects, federal grants and loan guarantees that have provided more support for financing of these projects, and accelerated permitting by the Federal government of specific projects. Most notably, the Company's project developers have been successful in taking advantage of significant federal incentives that had a limited window of opportunity to bring projects to fruition.[9]

At the start of the previous Action Plan Period in 2010, Nevada Power's RPS portfolio included approximately 230 MW of operating renewable energy. By the end of 2012, Nevada Power expects that figure to have grown to 610 MW of commercially operating renewable energy facilities, an increase of over 150 percent in just three years. The Company's Renewable Generations incentive program, which provides rebates to residential, small businesses, schools and other government agencies to install solar panels, as well as small wind and hydro-electric generating plants, has seen a tripling in the number of megawatts delivered to the system over the last year. After over a decade of failed attempts by developers, the first utility-scale wind project in the State will begin renewable energy deliveries by the end of 2012 near Ely. Geothermal energy has increased by 200 percent from 2009 to 2012. Solar will increase by over 100 percent and biomass will increase over 1000 percent during the same period.

In addition to the over 350 MW of new renewable energy that will begin delivering to the Company in 2012, Nevada Power expects another nearly 200 MW to begin operating in 2013. This includes two new solar photovoltaic projects in Southern Nevada, and the Crescent Dunes facility near Tonopah, which will use first of its kind technology to deliver stable solar energy to the system even after the sun goes down. The Company's

[9] Most notable of the federal incentives among Nevada Power's portfolio are: (1) the Section 1603 treasury grant which was adopted as part of the American Recovery and Reinvestment Act ("ARRA") which provided a cash grant in lieu of a tax credit for renewable projects that began construction before the end of 2011 and completed construction prior to the expiration of the relevant tax credit deadline, and (2) the Section 1705 loan guarantee program, also part of the ARRA, which provided loan guarantees for renewable projects, which was no longer available after September 30, 2011.

RPS portfolio includes renewable projects under construction in every part of Nevada this year and next, drawing on all of Nevada's different renewable resources.

Ultimately, the primary indicator of the Company's renewable success rests in its ability to meet the RPS, which Nevada Power has now done for two consecutive years. Just as important to these successful efforts is the fact that the Company has been able to meet the increasing RPS while controlling the cost of its renewable portfolio for customers, through competitive procurement, the use of efficiency measures and all of the tools available under Nevada law.

The variable nature of the RPS inherently means that there will be times when the Portfolio Credits ("PCs") exceed the RPS requirement. Surplus PCs have value that must be considered differently than energy because their legal life is indefinite. While they could be used at any point in the future, there may be benefits to selling surplus PCs in order to create near-term value for customers or offset current energy costs. Because Nevada Power will likely confront this surplus situation during the Action Plan Period, the Company has set forth its approach to realizing this value for customers in the Section labeled "Surplus PCs" below.

While Nevada Power is able to meet the growing RPS and currently forecasts compliance through 2020, the Company is requesting approval to continue to procure renewable resources that provide value based on the multiple policy objectives of the legislature that fostered the development of the RPS. These objectives include environmental benefits, diversifying fuel sources and providing economic benefits such as developing Nevada jobs. For example, Nevada Power's service territory includes one of the best solar resources in the U.S. As solar pricing continues to fall, Nevada Power seeks to take advantage of these and other cost-competitive opportunities during the Action Plan Period. The Company proposes to undertake these efforts by issuing at least one and perhaps two requests for proposals ("RFP") in 2014 and/or 2015 for up to 250 MW[10] of new renewable resources located in close proximity to Nevada Power's load centers. This would enable the Company to be in the position to take advantage of opportunities that would assist in the continued development of this vital sector of the local economy, diversify the Company's energy generation sources, and respond to contemplate any potential change in current planning assumptions (e.g., an unexpected change in load growth or new regulations impacting other generation sources). Moreover, because PCs do not expire in Nevada, unused credits can be used in future compliance years after 2020.

While the Company has experienced recent success in its renewable planning strategies, the process remains fluid and dynamic. From the inception of the RPS, the Company faced unique challenges in meeting new and escalating state RPS requirements. First, the Company was just beginning to emerge from the crisis in the Western wholesale markets with limited procurement opportunities due to the Company's financial situation. Second, Nevada was the fastest growing state in the nation so the Company was facing

[10] 250 MW would be the total expected new renewable capacity during the Action Plan Period unless additional amounts are required to meet energy or RPS requirements.

dramatic growth in its retail load (the basis of the new and growing RPS requirement). Finally, unlike Sierra, which had a large portfolio of legacy geothermal projects dating back to the 1980s, Nevada Power had no significant renewable resources in its portfolio, and its resources were largely more expensive than projects in Sierra's territory. The Company met this challenge by developing a comprehensive strategy for meeting the RPS that included: 1) long-term power purchase agreements ("PPAs"); 2) direct investment in renewable facilities; 3) demand side management ("DSM") activities; and 4) transmission improvements that would enable the Company to take advantage of lower-cost renewable technologies in Northern Nevada.

Given the Company's progress to date and changes in the marketplace, the Company's compliance strategy has shifted. A key component of Nevada Power's current compliance strategy is the implementation of modeling techniques to more accurately reflect shortfalls, delays, and the historic rate of project cancellations experienced within the RPS portfolio. Based on the current forecast and current law, Nevada Power is able for the first time to forecast total RPS compliance throughout the Action Plan Period January 1, 2013 through December 31, 2015. Accordingly, in this filing, Nevada Power is not seeking approval of any new Company-owned renewable energy projects or acceptance of any new renewable energy PPAs, although it is seeking to issue RFPs during this time. The Company will remain vigilant in analyzing any potential changes, including load changes or changes in law that may cause this forecast to become inaccurate, thereby triggering a change in approach and potentially the need for future amendments to this IRP. As has previously been presented in recent IRPs and IRP amendments, the Company has developed a renewable expansion scenario that will enable the Company to continue to meet its RPS obligation under three load forecast assumptions (low, high, and base). The renewable expansion scenarios incorporate the new and more rigorous RPS requirements adopted by the 2009 Legislature (discussed above), and the step increase to 18% in 2013.

The foundation for the renewable expansion scenario remains, at a minimum, compliance with the RPS. It incorporates current projects in commercial operation and approved projects under development and construction, and removes any terminated projects. The modeling in this plan assumes that current commercial projects would be renewed when the contract expires if necessary to maintain RPS compliance, but would be renegotiated to reflect market pricing for that technology at that time. Because these projects are operating (thereby having proven a resource and constructed the necessary infrastructure, such as transmission and civil improvements), the expectation is that these facilities would likely present the most feasible options for the Company to meet a need for additional renewable resources at that time. This would not prevent the Company from making a different economic determination of the appropriate project choice at that point in time if there is a change in assumptions. Additional generic placeholder projects are introduced into the Company's expansion plan in future years only when alternate contract extensions are not sufficient to maintain RPS compliance. In addition, the renewable expansion scenario takes into account the contribution of DSM, station usage credits, and PC-only contracts, all of which contribute to compliance with RPS targets pursuant to Nevada law. Details of each renewable expansion plan (base, low, and high) are set forth in Technical Appendix REN-1.

While Nevada Power's renewable energy portfolio is adequate to satisfy the RPS through the Action Plan Period, the Company is acutely aware that federal incentives have expiration dates looming (solar through 2016, geothermal through 2013, and wind through 2012), after which future renewable development may be more difficult, challenging the Company's ability to meet their ongoing RPS compliance requirements after the Action Plan Period. Although no new power purchase agreements with renewable energy projects are presented for approval in this 2012 IRP, the Company is asking the Commission to consider and approve a program for marketing surplus PCs, as well as approval of the actions described below.

1. Issuance of One or More RFPs for No More than 250 MW of Renewable Energy During the Action Plan Period

   The Company is requesting approval to issue one or more RFPs (in 2014 and/or 2015) for new renewable resources located in close proximity to Nevada Power's load centers not to exceed 250 MW of nameplate capacity in total during the entire Action Plan Period.

2. Amendments to the previously approved Long-Term Portfolio Energy Credit and Renewable Power Purchase Agreement between Nevada Power and ORNI 42, LLC, dated February 2, 2010 (Tuscarora formerly Hot Sulphur Springs II):[11]

   i. The Third Amendment establishes an hourly cap on the geothermal facility and formally recognizes a name change to Tuscarora. This Amendment is provided as Technical Appendix REN-2

   ii. The Fourth Amendment is in connection with financing and addresses the Department of Energy's ("DOE's") perceived exposure to "change in law" risk. The Fourth Amendment only applies if the hourly energy cap established through the Third Amendment is removed and the expansion option is exercised. This Amendment is provided as Technical Appendix REN-3.

3. Variable Generation Integration Study

   The Company is requesting funding, not to exceed $800,000, to undertake studies of intermittency impacts and ancillary service cost if it determines additional information is necessary during the Action Plan Period to address the NAC requirements with respect to ancillary service costs[12].

[11] As required by NRS §704.7821 of the Nevada Revised Statutes, Nevada Power seeks a determination that the amendments are prudent and that the terms are just and reasonable.

[12] In order for the Commission to approve a long-term renewable energy contract the Company must provide specific information as required by numerous provisions of the Nevada Administrative Code ("NAC"). NAC 704.8885(2)(h) requires the Company to address the requirements for ancillary services.

2. RENEWABLE GENERATING FACILITIES

Per the National Renewable Energy Laboratory ("NREL"), Nevada is fortunate to have significant renewable resources throughout the state, including some of the greatest solar and geothermal potential in the country. The greatest solar resource in the state actually overlaps with significant portions of Nevada Power's service territory. While Nevada's wind regime is weaker than comparable states (based on wind speed and resulting production capacity), there are sites dispersed throughout the state that provide a utility-scale resource. As technology costs have fallen for wind and solar, all three renewable technologies, wind, solar and geothermal, present comparable economic options throughout the state, especially if they are in close proximity to transmission access.

Nevada Power has been able to contract for many of Nevada's prime renewable resources through long-term PPAs, and is now seeing the results of these efforts as numerous projects complete construction and begin operating. The following list sets forth all of the facilities that are expected to be operating and contributing to RPS requirements by the end of 2012:

1. Goodsprings Recovered Energy Generation Station

   The Goodsprings Recovered Energy Generation Station is located 35 miles south of Las Vegas. It is a 7.5 MW generating plant which converts waste heat from a natural gas pipeline compressor station to electrical energy. The project was approved by the Commission in 2008. It is owned by the Company and started producing energy in 2010.

2. Desert Peak 2 Geothermal Power

   The Desert Peak 2 facility is a 19 MW geothermal project located in Churchill County, NV. The project was approved by the Commission in 2003. It is owned by Ormat Technologies and began producing energy in 2007.

3. Faulkner 1 Geothermal Power Plant

   The Faulkner 1 facility is a 49.5 MW geothermal project located in Humboldt County near Blue Mountain, NV. The project was approved by the Commission in 2007. It is owned by Nevada Geothermal Power Company and began producing energy in 2009.

4. Galena 2 Geothermal Power Plant

   The Galena 2 facility is a 13 MW geothermal project located in Washoe County south of Reno near Steamboat, NV. The project was approved by the Commission in 2003. It is owned by Ormat Technologies and began producing energy in 2007.

5. Jersey Valley Geothermal Project

The Jersey Valley facility is a 22.5 MW geothermal project located in a remote area in both Lander and Pershing Counties. The project was approved by the Commission in 2007. It is owned by Ormat Technologies and began producing energy in 2010.

6. McGinness Hills Geothermal Project

The McGinness Hills facility is a 51 MW geothermal project located in a remote area in both the Lander and Pershing Counties of Nevada. The project was approved by the Commission in 2010. It is owned by Ormat Technologies and began producing energy in 2012, ahead of the PPA deadline date of 2014.

7. Salt Wells Geothermal Plant

The Salt Wells facility is a 23.6 MW geothermal project located in Churchill County east of Fallon, NV. The project was approved by the Commission in 2007. It is owned by Enel North America and began producing energy in 2009.

8. Stillwater 2 Geothermal Plant

The Stillwater 2 facility is a 47.2 MW geothermal project located in Washoe County. The project was approved by the Commission in 2007. It is owned by Enel North America and began producing energy in 2009.

9. Tuscarora Geothermal Plant

The Tuscarora facility (formerly known as Hot Sulphur Springs 2) is a 25 MW geothermal project and allows for an expansion of up to an additional 25 MW by the project (for a total of 50 MW). The owner, Ormat Technologies, installed a 32 MW generator and began producing energy in 2011. The project was initially approved by the Commission in 2010. An amendment to contemplate the change in nameplate capacity from 25 MW to 32 MW is submitted as part of this filing.

10. Las Vegas Valley Water District ("LVVWD"; six projects)

The LVVWD projects comprise six Las Vegas-area solar photovoltaic projects totaling 3.1 MW owned and operated by PowerLight Corporation. The projects were approved by the Commission in 2005. These installations began producing electricity in 2006 and 2007.

11. Nellis Air Force Base, Solar Star

The Nellis AFB PV project is a 12 MW solar PV project that produces energy for Nellis Air Force Base, located north of Las Vegas. The project was approved by the

Commission in 2007. The project is owned by Fotowatio and began producing electricity in 2007.

12. Nevada Solar One

Nevada Solar One is a 69MW concentrating solar thermal plant that is located in the Eldorado Valley near Boulder City, NV. The project was approved by the Commission in 2003. It is owned and operated by Acciona Solar Power and began producing energy in 2007.

13. RV Apex Solar

The RV Apex Solar facility is a 20 MW solar PV project located in Clark County north of Las Vegas. The project was approved by the Commission in 2009. It is owned by Sun Edison and will begin producing energy in 2012.

14. Silver State Solar

The Silver State Solar facility is a 52 MW solar PV project located in Clark County near Primm, NV. The project was approved by the Commission in 2010. It is owned by Enbridge and began producing energy in 2012.

15. Stillwater 2 Solar

The Stillwater 2 Solar facility is a 22 MW solar PV project located in Washoe County, NV. The project was approved by the Commission in 2011. It is owned by Enel North America and began producing energy in 2012.

16. Spring Valley Wind

The Spring Valley Wind facility is a 151.8 MW wind project located in Spring Valley near Ely, NV. The project was approved by the Commission in 2010. It is owned by Pattern Energy and will begin producing energy in 2012.

17. CC Landfill Facility

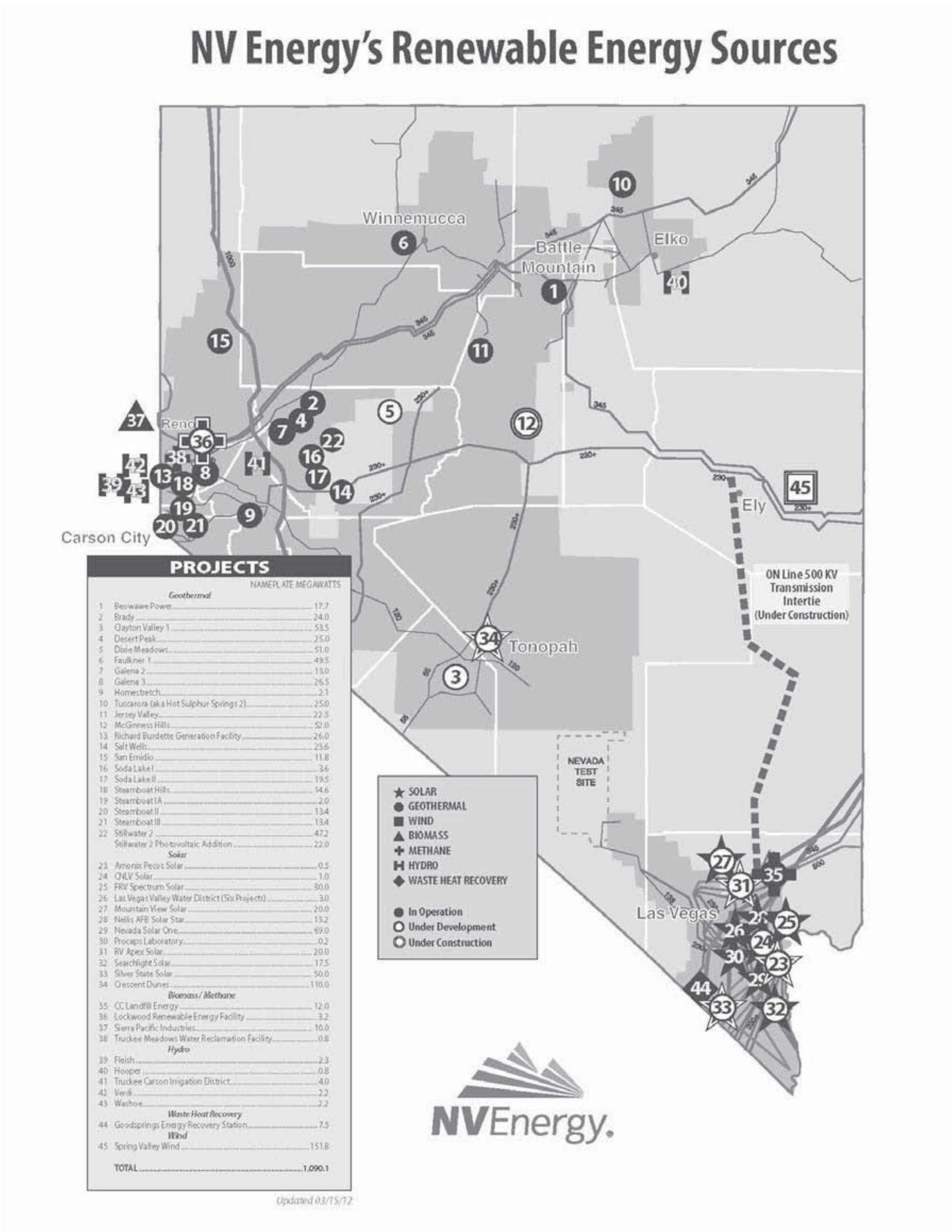
The CC Landfill facility is a 12 MW landfill gas-to-energy project located in Clark County, NV. The project was approved by the Commission in 2009. It is owned by Energenic and began producing energy in 2011.

18. Lockwood Renewable Energy Facility

The Lockwood facility is a 3.2 MW landfill gas-to-energy project located at the Lockwood Landfill near Reno, NV. The project was approved by the Commission in 2010. It is owned by Waste Management and began producing energy in 2012.

Existing renewable energy projects previously approved by the Commission are shown on Figure SS-8 below, which includes facilities contracted to Sierra.

FIGURE SS-8 – NVE RENEWABLE ENERGY MAP



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3. RENEWABLE ENERGY PLANNING

Renewable power purchases will continue to provide the majority of portfolio energy credits for the Company in the near and long-term. Because the Company has only a contractual relationship under the PPA and does not directly control the dispatch and operation of the facilities, it is essential that the Company effectively employ modeling techniques to more accurately reflect shortfalls, delays, and historically high project cancellations that are experienced in the renewable industry. The renewable projects that Nevada Power has contracted with in the last two years have been more successful in meeting their contractual obligations. Nevertheless, the Company will continuously monitor its portfolio to ascertain whether this was an anomaly due to federal incentives or if there is a true change in the outlook for renewable project development in Nevada. By having a flexible modeling process that focuses on more recent activities, the modeling used by the Company attempts to forecast based on this quantitative data and recent history. In determining its future PC needs, the Company must carefully consider several objectives:

1) Complying with an escalating RPS requirement;

2) Balancing the risk of non-compliance if too few renewable PPAs are executed against the cost to customers of potential over-procurement (especially given the high level of uncertainty regarding individual project success;

3) Repaying 2.6 million kPCs drawn by Nevada Power from the credit pool with Sierra and retired (i.e. used) to meet its past compliance obligations; and

4) Providing some "cushion" to allow for unexpected events on the demand side of the equation (against which the RPS is actually measured) in each calendar year, such as a sudden uptick in retail sales or a change in Nevada's renewable energy law.[13]

In order to address each of these objectives, the Company developed a renewable expansion plan based on probability modeling (Monte Carlo simulation). The probability modeling compares the Company's projected RPS requirement against its projected credit supply.

The annual RPS credit requirements were calculated in compliance with NRS 704.7821, which sets forth the annual PC requirement for the Company based on a percentage of total electricity sold to its retail customers during a calendar year. The expected PC supply was determined starting with the current portfolio of approved projects (reduced

[13] The Company is not currently adding a "cushion" above the RPS for the demand part of the forecast based on concerns raised by Staff and BCP in Docket No. 11-03014 about the sufficiency of the margin established for the supply side. While the current supply adjustment may be sufficient while there is still on-going development activity, it will likely need to be addressed again when the supply-side adjustments are reduced as projects become commercially operable.

by projects that have been terminated or are currently not operating),[14] both operating and under development. Several assumptions are built into the forecast.

- First, the PC supply forecast assumed that existing contracts will expire in accordance with their terms, but will be renegotiated as the most likely economic replacements to meet RPS compliance at the then-prevailing rate for that technology;
- Second, operating contracts are assumed to supply their existing contractual requirement in each calendar year of the PPA;
- Third, PCs from the Renewable Generations incentive programs will continue at levels consistent with 2011 until funds are exhausted;
- Fourth, the plan assumed that twenty-five percent of annual PC requirements would be met from energy efficiency and conservation measures (i.e. DSM). This is the maximum amount permitted under current Nevada law;
- Fifth, the plan contemplates that Nevada Power will repay a significant portion of its 2012 non-solar ending pool balance to Sierra in 2013, with the remaining obligation modeled as nine subsequent annual installments ending in 2021[15];
- Finally, the plan assumed that the existing statutory and regulatory regime would not change.

In order to reduce the risk of non-compliance due to delayed, downsized or cancelled projects, the expected supply amounts for all projects in development or under construction were reduced. The first step in determining the amount of supply reduction was based on Monte Carlo analysis, which takes into account the best, worst and most likely supply for each project, but does not account for total project cancellations. As with the Company's Supplemental Filing of its First Amendment (Docket No. 11-03014), the minimum output for each contract was assigned based upon its status at the time of filing preparation and its contractual parameters (*e.g.* Clayton Valley Geothermal has not begun construction, so the plan modeled five potential years of no energy delivery with all other years having a minimum potential output of 71.3% of the contracted supply amount). A PPA project not yet under construction was assigned two potential zero output years for potential commercial operation delay and then three additional zero output years for operational issues, which could occur during the contract life (after which the Company would have a right to terminate). If the project was under construction and/or financed, the first two potential zero output years were removed. All non-zero output years over the contract life were modeled by using the least likely output and most likely output permitted under the contract terms without penalty. The expected value was set at the PPA's then-existing supply amount. The zero-output years and non-zero-output years were then combined into a weighted average to replicate the life of the

[14] The current portfolio includes all Nevada Power projects approved by the Commission other than projects that subsequently have been terminated, such as ORNI 20 (Grass Valley) and Carson Lake Basin (Vulcan).

[15] The repayment over ten years is a modeling protocol in the renewable planning process but is not intended to reflect how and when actual repayments would be made since such amounts would be depend on the factual circumstances that will occur during this time period (*e.g.*, load, renewable generation, changes in law, etc.).

project. The Monte Carlo software uses these parameters to create a beta-PERT probability distribution for each project based on the risk of delay or downsizing. The distributions generated were the result of 10,000 simulation runs. The expected renewable credit supply at P-80 (meaning there is only a twenty percent chance of the supply being lower) was then used to determine the renewable credit contribution for each project. Using this methodology, the Monte Carlo model predicted that projects currently in the development pipeline could reliably be expected to deliver between 67.5% and 92.1% of their expected PPA supply amounts. The variation in percentages is due to the type of technology, PPA terms and the number of zero verses non-zero years used in the calculations. Figure SS-9 below shows the Monte Carlo inputs modeled for projects under development or construction and predicted delivery amounts.

FIGURE SS-9 - MONTE CARLO INPUTS & PREDICTED DELIVERIES

Project Name	Term	Zero/Non-Zero Years	Lower Limit	PPA Supply kPCs	Upper Limit	Monte Carlo Weighted Output @ P80 [a.]	Weighted Avg (kPCs) [b.]	Monte Carlo % [c.]
Projects Under Construction:								
Fotowatio Apex PV	25	3	0	56,828	65,636	39,626		
		22	47,451	56,828	65,636	53,691	52,003	91.5%
SolarReserve Crescent Dunes	25	3	0	528,619	610,555	371,121		
		22	451,969	528,619	610,555	502,365	486,616	92.1%
Spring Valley Wind	20	3	0	346,500	363,825	246,864		
		17	246,881	346,500	363,825	315,776	305,439	88.1%
Projects Pre-Construction:								
Clayton Valley	20	5	0	330,000	433,125	226,414		
		15	235,125	330,000	433,125	297,219	279,518	84.7%
Dixie Meadows	20	5	0	315,010	415,813	213,742		
		15	113,404	315,010	415,813	246,870	238,588	75.7%
ACE Searchlight	20	5	0	43,835	53,041	30,178		
		15	39,452	43,835	53,041	42,314	39,280	89.6%
FRV Spectrum Solar	25	3	0	75,016	99,021	51,587		
		22	50,110	75,016	99,021	66,264	64,503	86.0%
NextEra Mountain View	25	3	0	53,897	71,144	36,667		
		22	36,650	53,897	71,144	47,968	46,612	86.5%
PC Only Agreements:								
CNLV Water Reclamation, Amonix	20	5	0	5,957	7,863	4,040		
		15	4,289	5,957	7,863	5,373	5,040	84.6%
Expansion Options:								
Hot Sulphur Springs 2 (Expansion Option)	15	5	0	168,521	212,336	114,574		
		10	0	168,521	212,336	114,574	114,574	68.0%
San Emidio (Expansion Option)	24	5	0	74,037	97,729	50,008		
		19	0	74,037	97,729	50,008	50,008	67.5%

Notes:

a. The expected # of kPCs per the Monte Carlo analysis @ 80% probability level

b. The expected # of kPCs weighted for zero and non-zero delivery years

c. The adjusted supply percentage (P-80, weighted average)

After developing the renewable baseline forecast described in the preceding paragraph, the Company added placeholder projects to ensure that the Company modeled full RPS compliance throughout the planning horizon. As described above, the Company assumed that existing contracts would be renegotiated upon expiration, because the facilities are operating and the necessary infrastructure (transmission, roads, etc.) would likely make them the most economic options at that time. Other generic placeholders were added to address future RPS requirements not yet met through existing contracts. Because all placeholders (including contract extensions) occur well after the current Action Plan Period, the Company would likely undertake RFPs to determine the best option to meet an RPS need at that time. Thus the underlying assumption can be revisited if other more economical options are presented at that time. Except for contracts with wind and solar projects, placeholder pricing was set at the most recent calendar year's lowest priced negotiated PPA, adjusted for inflation (which was also assumed to be market pricing for renegotiated contracts). Pricing for wind placeholder projects was adjusted by inflation minus one half percent (0.5%) to reflect improved turbine efficiency and recent pricing trends. Pricing for solar PV placeholder projects was adjusted by inflation minus one percent (1.0%) to reflect technology improvements and recent pricing trends. These reductions address concerns raised by Regulatory Operations Staff ("Staff") and the Bureau of Consumer Protection ("BCP") that certain technology prices are declining. The first RPS compliance gap requiring a generic placeholder project appears in 2020 and the first PPA expiration does not occur until 2027, well outside of the Action Plan Period.

Because the Monte Carlo analysis does not contemplate total project cancellation or failure, an additional adjustment was required to address these possibilities. The Company analyzed all 2007-2010 projects to determine the appropriate reduction factor. The analysis contemplated all of the post-2006 historical renewable energy losses directly attributable to project cancellations in order to determine the appropriate reduction that could be applied across the portfolio. Both historical data and current information on the development status of projects show that development risks such as permitting and resource shortfalls can be severe and can result in a significant amount of project attrition despite the efforts of highly motivated proponents. This portfolio-based approach enabled the Company to treat all projects proposed and/or under development equally and apply the same reduction factor, thereby avoiding the need to subjectively determine which projects are likely to be cancelled. Based on this analysis, the cancellation reduction factor was calculated to be thirty-four percent and the projected energy/credit supply for those projects that have not yet begun construction or provided confirmation of financing were reduced by such amount to properly account for the cancellation risk. The final supply adjusted amounts, reflecting both the Monte Carlo forecasted supply and the adjustment for project cancellations, are summarized in Figure SS-10 below:

FIGURE SS-10 - ADJUSTED SUPPLY AMOUNT REFLECTING MONTE CARLO AND CANCELLATION PROBABILITIES

PROJECTS UNDER CONSTRUCTION / DEVELOPMENT

Project Name	Monte Carlo Weighted Output @ P80 a.	Weighted Avg (kPCs) b.	Monte Carlo % c.	Attrition Adj. d.	Adjusted kPCs (after MC & Attrition)	Supply Amt. After all Adjustments e.
Projects Under Construction:						
Fotowatio Apex PV	39,626 53,691	52,003	91.5%	NA	52,003	91.51%
SolarReserve Crescent Dunes	371,121 502,365	486,616	92.1%	NA	486,594	92.05%
Spring Valley Wind	246,864 315,776	305,439	88.1%	NA	305,439	88.15%
Projects Pre-Construction:						
Clayton Valley	226,414 297,219	279,518	84.7%	34.0%	184,477	55.90%
Dixie Meadows	213,742 246,870	238,588	75.7%	34.0%	157,469	49.99%
ACE Searchlight	30,178 42,314	39,280	89.6%	34.0%	25,925	59.14%
FRV Spectrum Solar	51,587 66,264	64,503	86.0%	34.0%	42,574	56.75%
NextEra Mountain View	36,667 47,968	46,612	86.5%	34.0%	30,763	57.08%
PC Only Agreements:						
CNLV Water Reclamation, Amonix	4,040 5,373	5,040	84.6%	34.0%	3,327	55.84%
Expansion Options:						
Hot Sulphur Springs 2 (Expansion Option)	114,574 114,574	114,574	68.0%	34.0%	75,621	44.87%
San Emidio (Expansion Option)	50,008 50,008	50,008	67.5%	34.0%	33,003	44.58%

Notes:

a. The expected # of kPCs per the Monte Carlo analysis @ 80% probability level

b. The expected # of kPCs weighted for zero and non-zero delivery years

c. The adjusted supply percentage (P-80, weighted average)

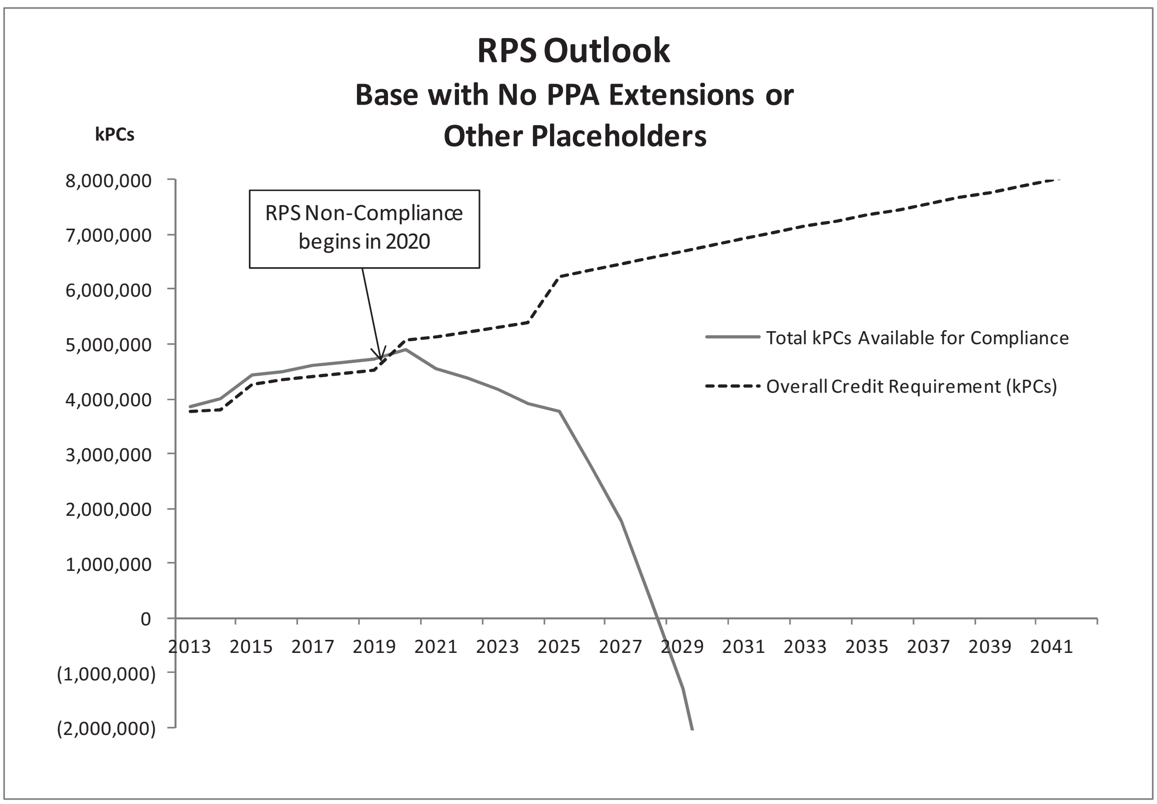
d. Attrition % based on the success of post-2006 PPAs. This adjustment was only applied to projects which have not substantially started construction as of 2/01/12

e. Post adjustment (Monte Carlo & Attrition if applicable) percentage of the original supply amount

Based upon the Company's experience, and given the many risk factors associated with developing new renewable projects, it is reasonable to assume a certain percentage of projects under development will not materialize or will not meet their full contractual supply obligations. The accuracy of the expected amount of renewable energy and PCs to be delivered under executed PPAs is improved by reducing the energy supply profiles for the entire portfolio using the Monte Carlo analysis, and uniformly applying the cancellation reduction percentage. By only applying these factors to early-stage development projects, the Company believes the adjustment provides a reasonable approximation to forecast the portfolio deliveries.

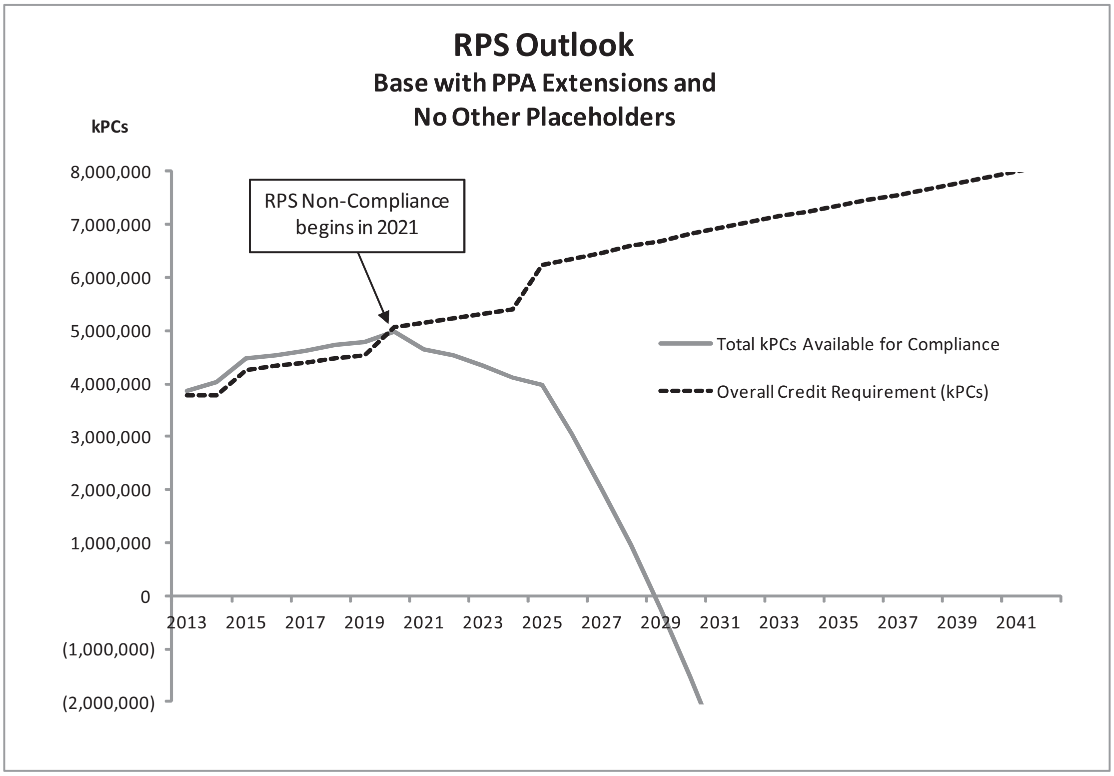
The following figures illustrate the effect of the changes to the Company's modeling approach. Figure SS-11 shows when the Company currently projects a need for additional renewable resources (whether a new PPA or the extension of an existing contract) for RPS compliance. The figure is based on the Company's current renewable portfolio and planning protocol under Base Load projections *with no generic placeholder or extension of existing contracts* (still assuming the ten-year repayment of kPCs to Sierra):

FIGURE SS-11 - RPS OUTLOOK WITH CURRENT PROJECTS ONLY
(NO EXTENSIONS OR NEW PLACEHOLDERS)



The following figure shows when the Company currently projects a need to add a renewable resource for RPS compliance based on its current renewable portfolio and planning protocol under Base Load projections *assuming extension of terminating PPAs with no generic placeholders added* (still assuming the ten-year repayment of kPCs to Sierra). The relative age of the Company's renewable portfolio limits the availability of significant contract extensions until late in the planning horizon.

FIGURE SS-12 - RPS OUTLOOK WITH CONTRACT EXTENSION AND NO OTHER PLACEHOLDERS



5. SURPLUS PCS

It would be extremely difficult, and likely impossible, for the Company to meet the RPS requirement exactly each year. Necessarily, this means that in some years the Company may have more PCs than are necessary for compliance with the RPS. The Company's sister utility, Sierra, has had a surplus of PCs for many years that have continued to aggregate. The RPS forecasts presented in the previous section suggest that Nevada Power may have surplus PCs during the Action Plan Period.

Surplus renewable energy and/or PCs can either be retained for future RPS compliance or sold to a third party. The sale of PCs today would accelerate the need for additional PCs in the future. The Company will evaluate potential opportunities to sell surplus renewable energy and/or PCs, to determine whether doing so creates a better value for customers than retaining the PCs for future compliance years.

The pricing of any potential sale would be dependent on several factors, including the market price of the product being sold, the cost to replace energy that is needed to meet load, the present value of the cost of replacing the PCs in the future, and any costs of delivering the product (e.g. transmission, ancillary services). The price would also vary with the type or class of PC to be sold (e.g., solar, non-solar, un-bundled PCs, without energy or station usage). Revenues from any such sales would be credited to customers through the deferred energy account adjustment ("DEAA") process.

The Company expects that any potential sale of renewable energy and/or PCs would be for a term of less than three (3) years because of the immediate nature of compliance requirements in most jurisdictions. If the Company determines that customers would be advantaged through a sales agreement with a term of three (3) years or longer, the Company would file such proposed transaction agreement with the Commission for approval in an IRP or IRP amendment.

Because forecasting RPS compliance is inherently uncertain and impacted by factors beyond the Company's ability to control (e.g., load and renewable project performance), the Company will only consider selling amounts of renewable energy and/or PCs that are forecasted to exceed ten percent (10%) of the forecast RPS requirement in any calendar year. For example, if the forecast RPS requirement for a given year is 1,000,000 kPCs and the Company forecasts it will have 1,300,000 kPCs, for that year, then it would consider selling up to 200,000 kPCs in the market.

6. RENEWABLE ENERGY RFPS

Through 2010, the Company annually issued renewable energy requests for proposals ("RFPs") to meet the renewable generation requirements of the RPS based on its need to add resources to assure compliance. Given the positive outlook for compliance through 2020, the Company is not currently contemplating the issuance of any RFPs in 2012--for long-term or short-term renewable purchases. While Nevada Power does not have a near-term need (in terms of compliance with the RPS or meeting customer demand), the resource planning regulations require the Companies to consider resource alternatives that mitigate risks related to flexibility, diversity, smaller project commitments, displacement of fuels, and future carbon regulation.[16] Additionally, the Company is cognizant that other policy objectives and pricing considerations may warrant issuance of RFPs during the Action Plan Period. Accordingly, Nevada Power is requesting approval for a narrowly tailored RFP that would enable the Company to seek out cost-effective renewable options for the benefit of customers as described further below during the Action Plan Period. Given the concerns raised by Regulatory Operations Staff and the Commission in Docket No. 11-03014 and Docket No. 11-09018, the Company is seeking advance approval of a specifically defined scope for the RFP to assure that the RFP objective is aligned with the desires of the Commission prior to issuance.

Over the course of the last Action Plan Period, the Company realized tremendous success from its renewable portfolio due to many factors that have been described above. Moving from RPS non-compliance to full RPS compliance was a significant accomplishment, but it now requires the Company, the Commission and the State to take a new approach in how new projects are analyzed. As the Commission indicated in the Order in Docket No. 11-03014, the regulations around the RPS warrant a renewed investigation to determine if the existing regulations, which were developed a decade

[16] NAC 704.937, paragraphs 1 and 5.

earlier, fit with the changed environment. The Commission established Docket No. 11-09018 to determine certain outstanding questions around need and various regulations and has just opened a rulemaking (Docket No. 12-04016) to address these concerns. The Commission's regulations will also need to be harmonized with any legislative changes that may occur in the 2013 session. Accordingly, the Company would not undertake any new RFP until 2014 (as further described below).

As previously described, the Nevada Legislature has cited multiple policy objectives in favor of the development of the RPS. These objectives include environmental benefits, diversifying fuel sources and economic benefits such as job development. Recognizing these policy goals and objectives, Nevada Power is requesting approval to continue to procure renewable resources in or near its service territory and in close proximity to its load centers that take advantage of the improving price paradigm for local natural resources. Resources located in or near Nevada Power's service territory reduce line losses and improve expected reliability from such systems and would complement the existing geothermal resources that would be delivered through ON Line. While Nevada Power does not require a supply-side resource to meet retail load until 2018, and does not require energy from renewable resources to meet the RPS prior to 2020, it believes the policy objectives of the RPS warrant consideration of renewable energy projects after meeting the RPS as described above, especially where pricing is favorable and federal tax incentives remain available.

Accordingly, Nevada Power is requesting approval to issue one or two RFPs during 2014 and/or 2015 for not more than 250 MW of new renewable resources. The expectation is that Nevada Power would present no more than 250 MW of new nameplate renewable capacity for approval by the Commission during the entire Action Plan Period. This proactive approach will enable the sector to continue to thrive in Nevada and secures additional resources to meet increases in forecasted load or changes in current fuel price assumptions. If the Company's load forecast were to change due to any circumstance, such as the economy or weather, Nevada Power would revisit if there is a need to increase the total number of megawatts from such a renewable solicitation. Nevada Power would prefer those resources that are located closest to its retail load and in its service territory as part of the RFP, in order to maximize the use of existing infrastructure and limit transmission line losses.

As solar pricing continues to fall, Nevada Power sits in one of the best solar resource in the United States and, through its RFP, would seek to take advantage of these and other cost-competitive opportunities during the Action Plan Period. The pricing for solar energy has allowed the Company to focus on the benefits of its supply profile, which normally coincides with the Company's highest load demand in summer. In addition, the current deadline for new solar projects to take advantage of the federal Investment Tax Credit is 2016, so falling solar pricing combined with favorable tax benefits may make this the most opportune time to enter into these agreements. The Company would undertake these efforts by issuing one or two annual RFPs for new renewable resources located in close proximity to Nevada Power's service territory and load centers in 2014 and/or 2015 not to exceed 250 MW in total during the Action Plan Period. This would enable the Company to continue developing this vital sector of the local economy and diversifying its fuel sources to contemplate any potential change in the current planning assumptions, such as a change in law affecting natural gas or coal. While the energy is not currently necessary for load requirements, new renewable generation will mitigate future open energy positions. In addition, these renewable facilities could meet any unexpected changes in load and, because portfolio credits do not expire in Nevada, the credits generated could be used in future compliance years after 2020.

Because a key goal of the new RFPs is to obtain the most cost-effective renewable projects for the benefit of customers and is based on taking advantage of a declining market price environment, Nevada Power would undertake a competitive process where the primary comparison would be on the price competitiveness of proposed projects because the goal is to undertake proposals that create the greatest value for customers, by taking advantage of falling prices and near-term tax incentives. Accordingly, the Company would only present projects that are priced below the most recent lowest-priced renewable PPA approved by the Commission for the Company at that time and then only those projects that beat the threshold by the greatest amount (but under no circumstances more than 250 total nameplate MW during the Action Plan Period). Ideally, the MW would be evenly divided between two solicitations in 2014 and 2015, with 125 MW awarded from each RFP. If no proposals meet the pricing threshold, then the expectation is that no new project agreements would be entered or presented for approval from that RFP. This enables the Company to assure that only the best value renewable options are presented for customers even if timing indicates they are earlier than needed for RPS compliance. Recognizing that a key goal of the RPS is economic development and environmental benefits for Nevada Power's customers, as further delineated in the Nevada Administrative Code Section 704.8885 and 704.9357, the Company would prefer those projects which are located closest to its service territory and load centers.

Nevada Power's continuing obligation to Sierra will cause it to undertake offers to residential customers and school customers in Nevada in each year of the Action Plan Period for the purchase of certified PCs which are not otherwise committed to another purchaser, in accordance with past practice. This would not apply to facilities that are already committed to Nevada Power or Sierra by participating in an applicable incentive program. Nevada Power will need to closely monitor its portfolio to determine if there is a change in circumstances that could cause it to revisit the need for any larger or additional RFPs. If it appears that challenges and delays encountered during permitting or difficulty securing financing is forcing developers to cancel or delay their projects, the Company will revisit the need for a larger RFP or will look to short-term contracts to fill any gaps.

7. ORNI 42 LLC AMENDMENT

As part of Docket No. 10-03022 submitted in March 2010, Nevada Power sought approval for a PPA with ORNI 42, LLC (at that time known as Hot Sulphur Springs II). ORNI 42 is a special purpose limited liability corporation and wholly owned subsidiary of Ormat Nevada, Inc. ("Ormat"). The Hot Sulphur Springs II geothermal contract was approved as a 25 MW (16.2 MW net) geothermal project expected to produce approximately 142,000 MWh and 176,633 kPCs annually. The contract also had an option for a potential expansion of a second 25 MW generator priced at the first geothermal unit's price.

On July 30, 2010, the Company executed the First Amendment to reflect an extension of the Company's right to terminate the ORNI 42 PPA in the event the Company did not receive the anticipated approval from the Commission for the proposed ON Line. On September 30, 2010, the Company executed the Second Amendment to the ORNI 42 PPA to extend the termination date set forth in the First Amendment. In addition, the Second Amendment revised the project milestones reflected on Exhibit 6 of the PPA to extend all project milestones by approximately three and a half months.

In late 2011, the Company learned that Ormat installed two geothermal units each with a nameplate rating of 20 MVA with a power factor of 0.8 (nominal nameplate rating of 16 MW each). Given that the contract specified the first unit capacity was limited to 25 MW, and that the expansion option was also limited to an additional 25 MW, the Company investigated whether there was a contract discrepancy. After discussions, Ormat confirmed they did not intend to execute upon the expansion option and thus the Company began negotiating a resolution that would protect its customers from the costs associated with the larger size of the facility.

The Third Amendment to the ORNI 42 PPA establishes an hourly energy cap of 19.4 MWh ("Maximum Amount") on the installed 32 MW geothermal facility, which causes the contract to replicate the delivery that would have been possible with a 25 MW facility. The original PPA allows Ormat to deliver up to 110% of the contracted monthly energy amount at the contract rate of $88.00 per MWh before the reduced rate of $45 per MWh excess energy rate is applied. However, the parties have agreed that if at any given hour the generating facility delivers energy in excess of the Maximum Amount, the amount of energy that is delivered during that Maximum Amount hour is delivered free of charge. In addition, the Company will receive renewable portfolio credits for all energy delivered during this period. The Third Amendment also gives Ormat seven and one half years from the date of commercial operation to remove the 19.4 MW cap; however, if Ormat elects to remove the cap it forfeits the option to add a final generation unit. Alternately, the cap can be removed simultaneous with the exercise of the option to increase the facility up to a total of 50 MW (as permitted in the original agreement). This Amendment also formally recognizes a name change for the facility, as requested by Ormat, from Hot Sulphur Springs II to Tuscarora. The Company believes this resolution protects its customers from purchasing excess energy due to a larger installed facility.

In addition to the Third Amendment, the Company has negotiated a Fourth Amendment to address Ormat's requirements in connection with financing backed with a guaranty by the Department of Energy ("DOE"). As was required by the DOE in connection with the Solar Reserve project in Tonopah, Ormat has indicated that DOE perceives an unacceptable exposure for "change in law" risk in the current PPA which must be resolved before committing to the financing, which is only relevant if the project undertakes further construction through the expansion of the facility. The Fourth Amendment only applies to the final unit expansion option. Therefore, if Ormat elects to remove the cap established in the Third Amendment without additional expansion, the Fourth Amendment would be void. Ormat has seven and one half years to exercise the option to expand the Tuscarora facility, which period begins following commercial operation of the first unit. In exchange for the Fourth Amendment, Ormat has increased their operating security from $20/MWh to $30/MWh, which would provide additional protection for the Company in the event of a default. Both amendments are provided as Technical Appendices: REN-02 and REN-03.

8. UPDATE ON RENEWABLE PPA DEVELOPMENT ACTIVITIES

Nevada Power is not presenting any new renewable PPAs for approval as part of this filing. The current expectation is that six previously approved PPA projects will not be operating prior to the filing of this IRP but are expected to achieve commercial operation during the Action Plan Period. Those projects expected to complete development during the Action Plan Period are listed below, together with changes to their status that have occurred since the refiling in Docket No. 11-03014.

1. American Capital Energy (Searchlight Solar I)

Searchlight Solar I is a 17.5 MW solar PV project near Searchlight, NV being constructed by American Capital Energy ("ACE"). ACE executed their Small Generator Interconnection Agreement ("SGIA") on January 28, 2011 with a commercial operation contemplated in late 2012. The interconnection agreement was completed later than originally contemplated under the ACE PPA. The project was approved by the Commission in 2009. The Company is in the process of negotiating with ACE with respect to the project delays.

2. Ram Power (Clayton Valley 1)

The Clayton Valley 1 project is a 53.5 MW geothermal plant located in Eureka County southwest of Tonopah, NV being developed by Ram Power Corp. Since receiving Commission approval, the BLM released the Clayton Valley Geothermal Exploration Project Environmental Assessment in April 2011. The BLM is currently reviewing agency and public comments. The first critical project milestone (project financing) under the Clayton Valley PPA is not required until December 2012, so there has not yet been any measurable status update for this project. The project was approved by the Commission in 2010.

3. Tonopah Solar (Crescent Dunes)

Tonopah Solar (Crescent Dunes) is a 110 MW concentrating solar power plant in Nye County, NV near Tonopah. It will use a solar power tower design with molten salt storage, as developed by Pratt & Whitney Rocketdyne. The solar power tower system utilizes a field of mirrors called heliostats that concentrate light onto a fluid in a central receiver, and the heat in this fluid is used to generate steam to drive a turbine to generate electricity. The Tonopah Solar project has begun construction and is on track to meet the PPA commercial operation date in 2014. Financing is complete. The power tower has largely been constructed and civil work is under way. The project was approved by the Commission in 2010.

4. NextEra (MountainView)

The MountainView project is a 20 MW solar PV plant located north of Las Vegas in Clark County, NV. The MountainView PPA has an engineering, procurement and construction ("EPC") Notice to Proceed deadline of July 2013 and has not indicated any delay in its schedule. Commercial operation is still expected in February 2014. The first critical project milestone (project financing) is not required until June 2013, so there has not yet been any measurable status update for this project. The project was approved by the Commission in 2012.

5. Fotowatio (Spectrum)

The Spectrum project is a 30 MW solar PV plant located north of Las Vegas in Clark County, NV. The Spectrum PPA has an EPC Notice to Proceed deadline of January 2013 and has not indicated any delay in its schedule. Commercial operation is still expected in July 2013. The first critical project milestone (project financing) is not required until January 2013, so there has not yet been any measurable status update for this project. The project was approved by the Commission in 2012.

6. Ormat (Dixie Meadows)

The Dixie Meadows project is a 51 MW geothermal project located in Churchill County, NV. The Dixie Meadows PPA has an EPC Notice to Proceed deadline of August 2014 and has not indicated any delay in its schedule. Commercial operation is still expected in April 2015. The first critical project milestone (project financing) is not required until August 2014, so there has not yet been any measurable status update for this project. The project was approved by the Commission in 2012.

7. Amonix PV Facilities

Amonix has contracts for two separate facilities in Clark County totaling 1.5 MW. They are expected to construct in 2012 and deliver only portfolio credits to the Company. They were approved by the Commission in 2011.

9. INTEGRATION OF INTERMITTENT RESOURCES

In order for the Commission to approve a long-term renewable energy contract, the Company must provide specific information as required by several provisions of the Nevada Administrative Code ("NAC"). Specifically, NAC §704.8885(2)(h) requires the

Company to address the ancillary services.[17] In Docket No. 11-03014, the Company requested approval of new renewable energy contracts and provided the best information then available regarding ancillary services. The Commission indicated that the Company needed to devote additional attention to ancillary services in future applications. In the Order for Docket No. 11-03014, the Commission reiterated that, for future renewable energy contracts submitted to the Commission for approval, the regulations require the Company to provide information regarding the price of ancillary services and the Company's ability to absorb energy. (Order Para. 116) The Order acknowledges that limits exist on the amount of renewable energy the Company is able to absorb (e.g., operational, physical, financial).

Due to the relatively small sizes of individual variable generation projects (compared to traditional fossil fuel generation) that are likely to be submitted to the Commission for approval, it is difficult to accurately quantify the impacts and, therefore, determine measures and upgrades needed for each specific variable generation("VG") project being analyzed. The impact of any single VG project on the Company's balancing authority ("BA") area, when considered by itself, is virtually undetectable, yet the cumulative impact from the portfolio of VG projects will be significant. The Company has completed numerous integration studies in the last five years, each considering unique aspects of VG. These integration studies have been technically challenging, ranged in cost from several hundred thousand to nearly one million dollars, involved timelines of up to eighteen months, and required detailed knowledge of Nevada Power's system operations and understanding of VG characteristics.[18]

Due to the high cost and the length of time needed to complete ancillary services studies, the Company seeks to make effective use of the results of the investment in the studies presented in prior dockets, as well as upcoming near-term operating experience, to the greatest extent possible as its strategy for meeting its statutory obligations related to the ancillary services for variable generation projects should they be proposed within the three-year Action Plan Period of this 2012 IRP. The two studies the Company proposes to use as primary analysis for the NAC are briefly described below:

<u>Large Scale Photovoltaic ("PV") Integration Study</u>

This study was completed in July 2011 and submitted to the Commission pursuant to a compliance item ordered in Docket No. 10-02009. The Large Scale PV Integration study provided a comprehensive analysis of the regulation requirements for a wide variety of PV penetration scenarios, with sensitivities for a reasonable spectrum of distributed PV generation as well. The results of the study projected integration costs-per-delivered-

[17] "Ancillary Services" as defined by NRS 704B.020 are those generation services that: (1) Are necessary to support the transmission of energy and capacity from resources to loads while maintaining reliable operation of the transmission system of the electric utility; and (2) are defined and established in applicable transmission tariffs on file with the Federal Energy Regulatory Commission.

[18] The Wind Integration Study took 18 months to complete at a cost of $360,000; the Solar PV Distributed Generation Study took 6 months to complete at a cost of $260,000; and the Large-Scale Solar PV Integration Study took 12 months to complete at a total cost of $943,000 (DOE funded $450,000).

MWh provided an estimate of the amount of additional regulation capacity that needed, and the performance requirements of such regulation for a range of large scale PV from the 150MW level to over 1,000MW. The modeled projects in this study sufficiently cover the geographic area of Southern Nevada service territory. Therefore, the Company suggests that the data to support the NAC requirement for ancillary services for any future PV projects that it may propose during the Action Plan can be inferred from this Large Scale PV Integration Study, thereby avoiding the time and expense of a separate and unique study for each new project.

Report on Integration of Renewable Resources in Northern Nevada

This analysis, submitted to the Commission as part of the 2009 IRP (Docket No. 10-02009), examined the ability of the Northern Nevada system to accommodate various degrees of wind-powered generation. Key findings from this analysis were 1) for the specific Spring Valley Wind project, with peak output of 150MW, an additional 35MW of regulating reserve would be necessary in order to avoid a significant decline in BA performance, and 2) at various degrees of integration of must-take geothermal capacity, the Spring Valley Wind project would likely have its output curtailed during hours of low electric system demand. In addition, while the analysis primarily focused on one particular site, Spring Valley, its results and conclusions related to several other potential wind project sites. From the analysis presented in this report, and the experience that the Company will gain following the Summer 2012 in-service date of the Spring Valley Wind project, the Company submits that it will be able to reasonably determine the amount of regulating reserve capacity that will be necessary for future proposed wind projects, and that it will better be able to compute the costs of such regulation and determine the degree of curtailment that may be necessary during minimum load demand periods. Further, while utilities have only limited experience with large-scale PV projects, there is a wealth of experience with large wind projects and the associated electric grid integration techniques available in the Western Interconnection. Significant projects have been integrated in the Pacific Northwest, Colorado, Montana and New Mexico. Operating data and performance statistics are available that could be used to support the determination of integration costs and the ability of the electric system to absorb future wind projects. Therefore, the Company believes that there is no compelling reason to conduct an expensive and time-consuming study of wind projects in Northern Nevada proposed within the three-year Action Plan Period. The Company believes that any wind-powered project that it may propose within that period can be satisfactorily analyzed in compliance with the regulations through the use of the prior analysis, upcoming experience with the Spring Valley Wind project and the wealth of experience that is being realized within the Western Interconnection.

Proposed Strategy for Quantifying Ancillary Services for the Action Plan Period

For each of the types of projects that may be proposed, the Company intends to satisfy the NAC 704.8885 (2)(h) for ancillary services in the following manner during the Action Plan Period:

Solar PV in Southern Nevada
The Company will make use of the 2011 Large Scale PV Integration Study to determine the costs and the regulation reserve requirements that will be necessary to integrate a proposed project of this type. The integration cost, as well as the ability to satisfactorily integrate the project to the grid, will be determined through use of the study results and through the effective modeling of the output profile of the project and the incremental regulation reserve requirements in the production cost simulations.

Wind-Powered Generation in Northern Nevada
The Company plans to use the analysis that was conducted in support of the report "Integration of Renewable Resources in Northern Nevada" to determine both the ability to accommodate the proposed wind project and the amount of incremental regulating capacity necessary to reliably balance the resource. The incremental regulating capacity will be included in the production cost simulation runs, and these simulations will also be able to determine the degree of project curtailment, if any, that will be necessary.

Wind-Powered Generation in Southern Nevada
Should a wind-powered generation project be proposed for the Southern Nevada area, the Company would attempt to use Northern Nevada wind experience along with meteorological data from the proposed Southern Nevada project site to determine a regulation reserve requirement and associated cost.

The Company believes that the above studies provide a reasonable proxy for cost estimates for ancillary service related to specific renewable projects pursuant to NAC 704.8885(2)(h) if new renewable projects are presented to the Commission for approval. However, in some instances, additional factors such as significant changes in load, or the merging of the Companies balancing areas, may necessitate further detailed analysis to determine a specific proxy to address NAC 704.8885(2)(h). Accordingly, the Company is requesting funding not to exceed $800,000, to undertake studies of intermittency impacts and ancillary service costs if such additional information is required during the Action Plan Period, and if prior studies are not able to provide a reasonable proxy for such information. This study (or studies) would seek to model the combined BA operation, and could include a variety of sensitivities of both PV (South) and wind (North), along with the subject southern wind project. A study of this nature would take upwards of one year to complete, but would only be undertaken if the prior studies are no longer suitable to quantify ancillary service costs for projects proposed during the Action Plan Period.

Included in such a study scope would be the following:

- Quantify the likely generation profile of such variable resources, based on locations (wind or solar resource available), sizes and technologies;
- Estimate integration cost under different assumptions, including penetration level, variable generation technology, plant location and size;

- Estimate the impact on operating reserve levels and any other ancillary service requirements to accommodate the variable resources;
- Evaluate the impact of these resource additions on the BA's economic dispatch and existing generators;
- Assess the flexibility of the Company's generation fleet and adequacy to accommodate the variable resources;
- Identify impacts on the ability to comply with NERC control performance standards;
- Identify alternative strategies to manage variability and uncertainty more efficiently (real-time operations and scheduling time frames); and,
- Determine the capacity value of and planning capacity margin needed for the variable resources.

Other Ongoing Variable Generation Integration Activities:

The Company is presently participating in two projects that will inform how future renewable projects can be integrated into the Company's electric grid in the most reliable and economic fashion. Both projects are entirely funded by the DOE and are being conducted by Pacific Northwest National Laboratory and Sandia National Laboratory. The objective of the first study is to simulate real-time unit dispatch in the Company's system, allowing the simulation to analyze actual deployment of automatic generation control ("AGC") units and peaking units in capacity, ramp rates and cycling, and system control performance at various solar PV penetration levels. The second study is a Unit Commitment Analysis. Because uncertainty of variable generation output is an influential factor affecting operations cost and reliability risk, the objective of the study is to understand how a Stochastic Unit Commitment approach might be used to optimize parameters of system operations, economic dispatch, and generation reserve requirements.

In addition to these two analytical efforts, the Company also recognizes the value of a dependable VG output forecast. An accurate, high quality forecast can reduce the integration cost of renewable generation significantly. Because of this, the Company is planning a forecasting pilot project with solar- and wind-forecast providers to better understand forecasting benefits and forecasting providers' capability. The final goal of the pilot program is to determine the benefits of a centralized forecasting service for VG inside the Company's BA.

E. TRANSMISSION PLAN

1. INTRODUCTION

NAC §704.9385(3) requires that every IRP include a twenty-year transmission plan as a component of its supply side plan. This section presents Nevada Power's twenty-year plan for meeting the transmission needs of its native load customers as well as third party service requests. The transmission plan is built upon the system characteristics set forth in this filing (e.g., existing generation from Section 2.A.1. of this volume), existing transmission (Section 2.E.2. of this volume), and the current load forecast (Load Forecast and Market Fundamentals narrative in this filing). Based in part on these key system characteristics, the transmission plan examines the capabilities of the existing transmission system and determines the additional transmission facilities needed and the timing of those facilities. In addition, the transmission plan includes proposals to address transmission for the development of Nevada's renewable resources, both for internal consumption and for import into and export to other markets. Nevada Power's participation in WestConnect and interaction with regional and federal regulators also is discussed.

2. OVERVIEW OF NEVADA POWER'S TRANSMISSION SYSTEM

NAC §704.9385(3)(a) requires that the transmission plan include a description of the capabilities of the current transmission system. Nevada Power's transmission service area encompasses approximately 4,500 square miles, with 1,665 miles of Federal Energy Regulatory Commission ("FERC") jurisdictional transmission lines ranging from 69 kV to 500 kV. Transmission services are offered under the NV Energy Operating Companies' Open Access Transmission Tariff ("OATT").

Nevada Power's existing transmission system can be described in three sections, each of which is depicted in Figure TP-1 below. The first section is generally referred to as the Nevada Power internal system, and is shown as the area between the cut plane lines (the heavy dashed lines) in Figure TP-1. A cut plane is a reference to a combination of lines, either internal or external to a system, which due to their loading capabilities are collectively monitored or examined for congestion. The Nevada Power internal system is located within the Las Vegas Valley, where the vast majority of Nevada Power's customers reside. Except as described below, Nevada Power's ability to deliver resources is not presently limited by the transmission facilities within this area. Two import/export paths are also depicted on Figure TP-1.

The dashed line on the bottom-right of Figure TP-1 is known as the Southern Cut Plane ("SCP") and shows the paths through which Nevada Power brings in power from major substations on the southern interface of its transmission system – namely Mead, McCullough, and Eldorado – located south of Las Vegas in the Eldorado Valley. The SCP consists of one 500 kV and thirteen 230 kV transmission lines electrically situated in parallel with each other. These lines are connected to the Mead, McCullough, and

Eldorado substations. They connect to several trading hubs south of Nevada Power's transmission system and are used to import and export energy that is scheduled across this cut plane. Annual studies are performed to verify the capability of this cut plane and to identify the SCP transmission limitation.

The dashed line on the top-right of Figure TP-1 is referred to as the Northern Cut Plane ("NCP"), and comprises the Red Butte-Harry Allen 345 kV interconnection with PacifiCorp in Utah, and the Crystal interconnection with the Navajo-Crystal-McCullough 500 kV line. Annual studies are conducted in coordination with PacifiCorp to verify the capability of this cut plane and to provide the NCP transmission limitation. Figure TP-2 shows balancing area tie lines, existing Company-owned generation, and existing Independent Power Producer (IPP) generation.

FIGURE TP-1 - NEVADA POWER SYSTEM DIAGRAM

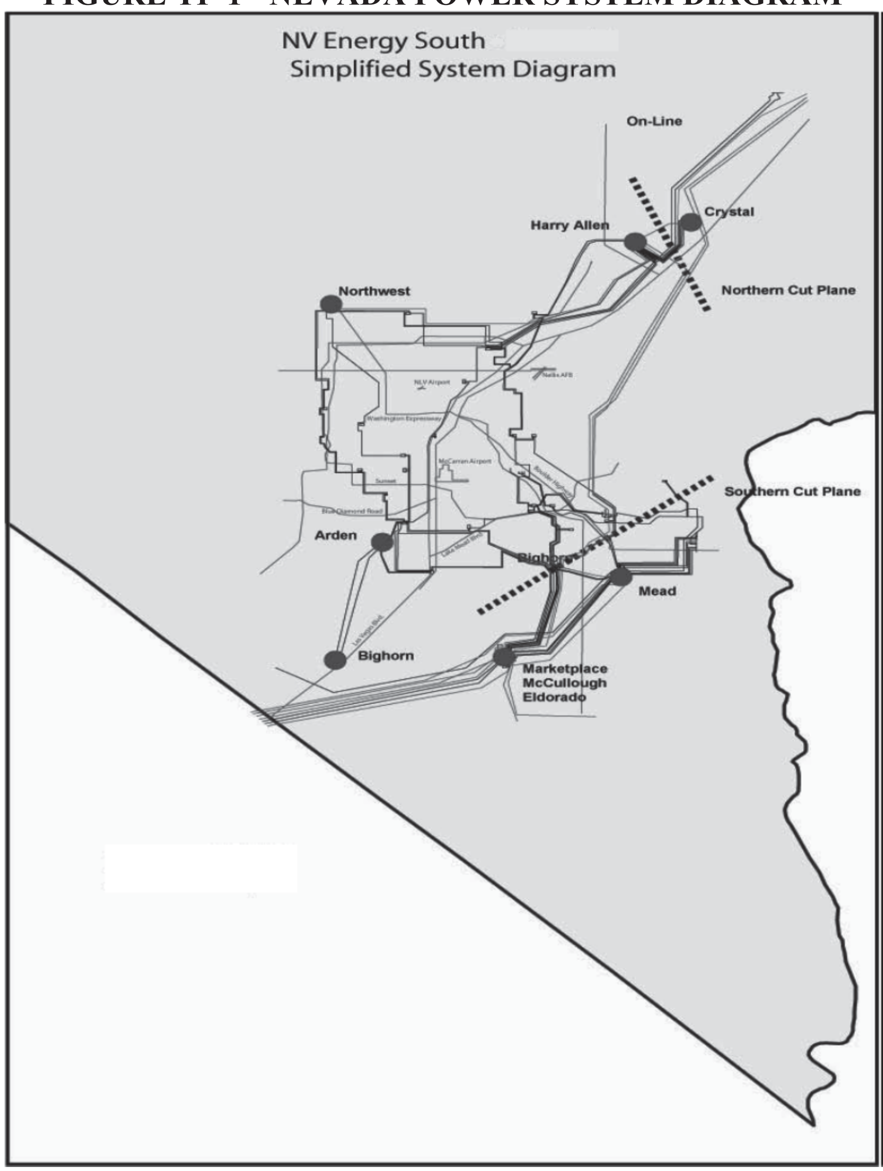
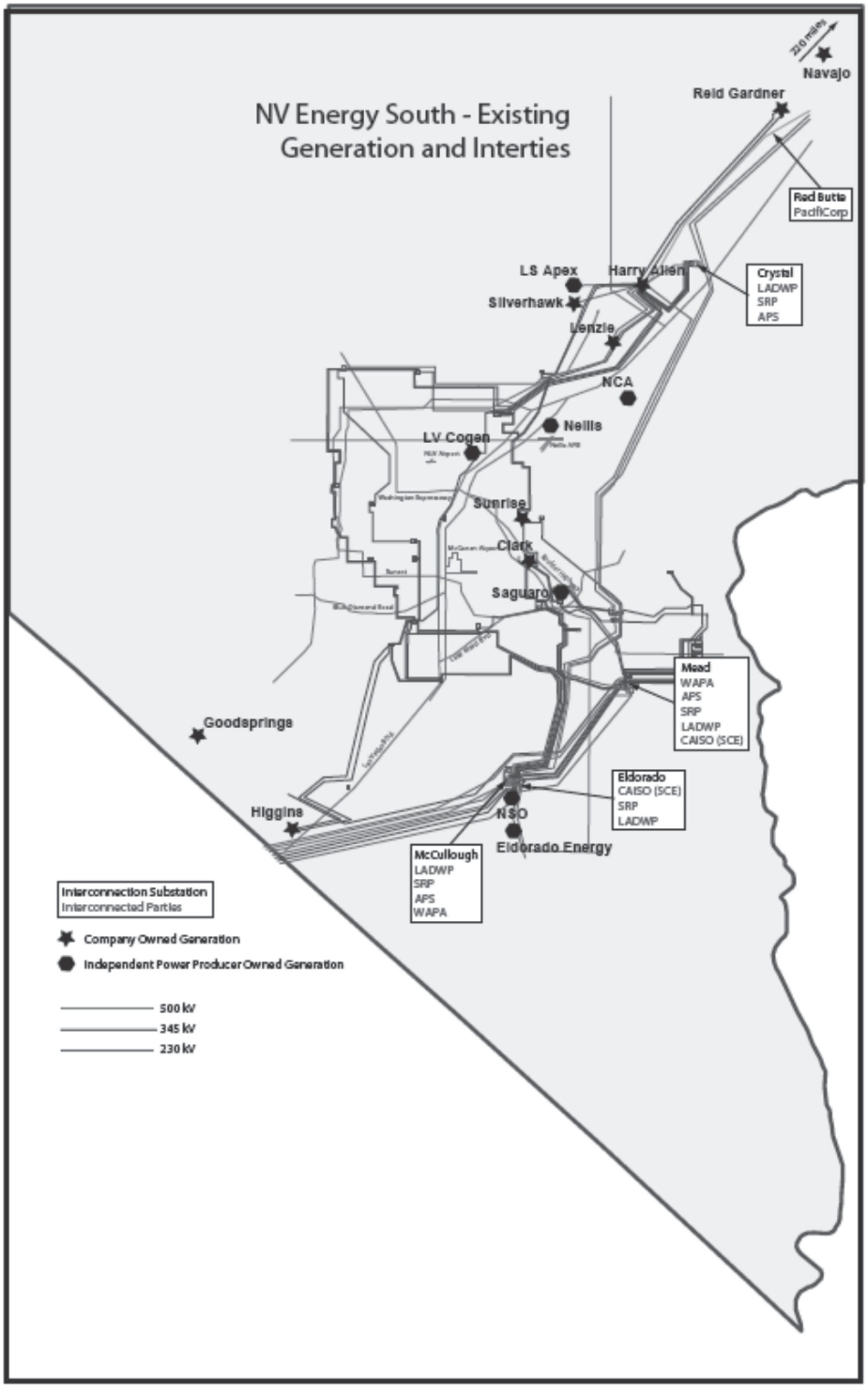


FIGURE TP-2 - DIAGRAM OF AREA TIE LINES, EXISTING COMPANY-OWNED GENERATION, AND EXISTING IPP GENERATION



3. TRANSMISSION PATH RATINGS

NAC §704.9385(3)(a) also requires that the transmission plan describe the path ratings for all significant transmission paths. Nevada Power owns three rated transmission paths, each consisting of one or more transmission lines that are rated in cooperation with the Western Electricity Coordinating Council ("WECC") and Nevada Power's affected neighboring entities within the WECC region. Nevada Power is also a partial owner of one additional WECC-rated transmission path, that being the WECC East of River ("EOR") Path 49. The transmission system of the Western Interconnection is often compared to a "donut," in that the major transmission lines form a circle with Nevada in its center. Transmission schedules along the west coast result in a portion of the transacted power flowing along the east side of the donut, through Idaho, Utah, Arizona, and Southern Nevada.

In anticipation of the completion of the ON Line, Nevada Power and Sierra have requested a re-definition of the WECC Path 81 (Centennial) reflecting the addition of ON Line and its effect on the proposed new path into the "Southern Nevada Transmission Interface" ("SNTI"). Descriptions of all rated transmission paths are provided below. These existing transmission path ratings are expected to remain unchanged with the exception of the re-definition of SNTI/Path 81, described in more detail below.

(A.) EXISTING RATED PATHS

(1) Crystal 500 / 230 kV Path (WECC Path # 77)

This path measures flows through the Crystal Substation transformers and allows energy to be moved from the Navajo-Crystal-McCullough 500 kV transmission line into the northeast corner of the Nevada Power system. This path is rated for 950 MW of inbound flow measured at the Crystal substation. This is a 230 kV phase shifter controlled path.

(2) Harry Allen – Red Butte 345 kV Path (WECC Path # 35 – TOT2C)

This path allows energy to be moved to and from Utah (PacifiCorp – East) and the northeast corner of the Nevada Power system at the Harry Allen switching station. With the addition of the second 345/230 kV transformer at Harry Allen in the summer of 2011, this path is now rated 400 MW of flow southbound (import) and 580 MW northbound (export). This path was redefined in the Gateway South Path Rating Study (A PacifiCorp Project in the WECC Path Rating Process) in 2011 to include the Red Butte – Harry Allen 345 kV line, two 345 kV phase shifters, and two 345/230 kV transformers at Harry Allen Substation. The two phase shifters control the WECC TOT2C path used to mitigate unscheduled flow in the WECC "donut." The full capacity of this path, however, is not available to Nevada Power due to PacifiCorp's rights to the second transformer (see discussion of PacifiCorp transformer).

(3) <u>East of River (WECCEOR Path #49)</u>

Nevada Power is a 26.1 percent owner of the Navajo-Crystal-McCullough 500 kV transmission line, one of several lines that comprise the WECC-EOR Path 49. On June 1, 2009, Nevada Power was allocated approximately 151 MW of additional transmission capacity across the EOR path by virtue of capital improvements made to a limiting series capacitor bank at the Navajo end of the Navajo-Crystal line segment. Nevada Power's bi-directional rights are now 522 MW on the Navajo-Crystal-McCullough 500 kV transmission line. This path (together with the West of River Path 46) is currently under study by SCE in order to re-examine (i.e., to confirm) the existing ratings since the Mohave Generating Station was decommissioned and SCE completed modifications to the Devers – Colorado River – Valley 500 kV system. At this point it is not certain whether SCE will be able to confirm these ratings or if they will have to be reduced.

(4) <u>Centennial Project (WECC Path # 81)</u>

The Centennial Path is rated at 3,000 MW. Centennial path flow is monitored at the Northwest Substation end of the Chuck Lenzie–Northwest 500 kV line, the Mead Substation end of the Harry Allen–Mead 500 kV line, and the Harry Allen Substation end of the Harry Allen-Crystal 500 kV line.

In November 2011, Nevada Power and Sierra requested a re-definition of this path when ON Line goes into service. This re-definition will effectively move the existing Path # 81 measuring points to the south (i.e., onto Nevada Power's SCP) and remove the existing 3000 MW limitation for the post-ON Line system configuration. Additional discussion is provided in Section (B) below.

(B.) ADDITIONAL RATED PATHS

(1) <u>ON Line and NV Energy Rating Consolidation</u>

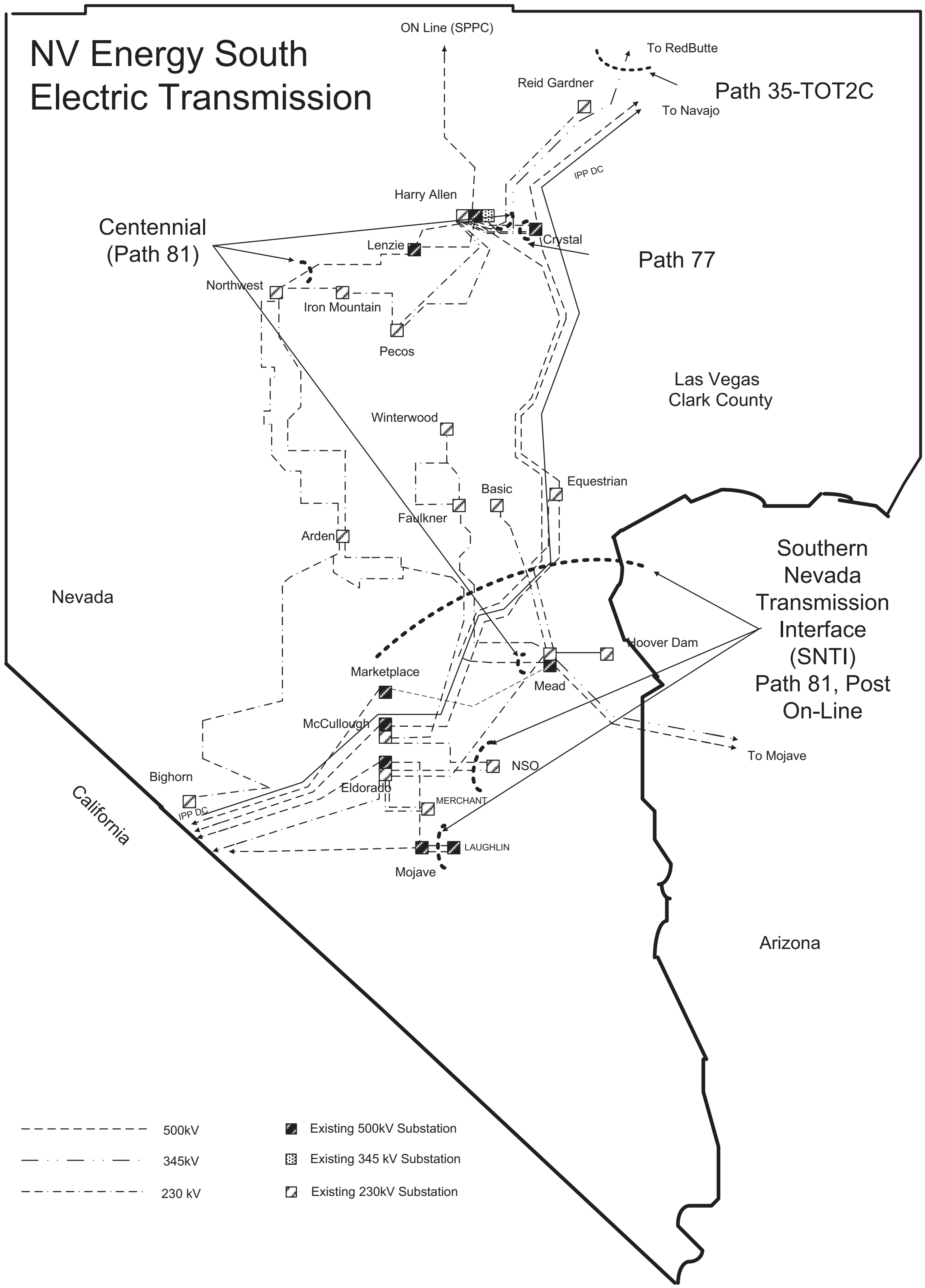
In anticipation of the completion of the ON Line, Nevada Power and Sierra originally initiated the WECC rating three phase process to obtain a rating for ON Line. ON Line (currently expected to be in service in the latter part of year 2013) will interconnect the North and South NV Energy Balancing Areas (BA), creating a combined BA. As ON Line will be an internal line to the combined BA, in November 2011, Nevada Power and Sierra announced to WECC members that they were instead requesting a re-definition of the WECC Path # 81 ("Centennial") into the SNTI. This re-definition will move the existing Path # 81 measuring points to the south, onto the Nevada Power SCP, and remove the existing 3000 MW limitation for the post-ON Line system configuration (see Figure TP-3). In March 2012, the Companies submitted a Comprehensive Progress Report ("CPR") and initiated the WECC Expedited Project Rating Review Process to obtain a new Accepted Rating for the re-defined Path # 81. According to the WECC Overview of Policies and Procedures for Project Coordination Review, Project Rating Review, and Progress Reports manual, after a 60-day WECC review period for the CPR, a Project Review Group ("PRG") is formed and the Expedited Rating process will proceed as a Phase II development. The process completion is dependent on the scope of comments received from the PRG and is expected by the end of 2012 or early in 2013.

(2) SNTI (WECC Path #81, as re-defined)

Nevada Power owns and/or operates the SNTI. SNTI is comprised of 21 transmission tie-lines between the new combined BA and the neighboring BAs in Southern Nevada (WALC, SCE & LADWP). The SNTI represents existing lines, and the path as a whole has been routinely evaluated and annually updated as a part of the seasonal operations studies. The current Total Transfer Capability ("TTC") of SNTI (as posted on NEVP OASIS) is 3500 MW South-to-North (NV Energy import) and 3050 MW North-to-South (NV Energy export).

Studies show that after ON Line goes into service, the TTC of SNTI (i.e., re-defined Path # 81) will be 3948 MW South-to-North (import) and 4465 MW North-to-South (export).

FIGURE TP-3 -POST-ON LINE PATH CONFIGURATION



4. IMPORT CAPABILITY

NAC §704.9385(3)(a) also requires that the transmission plan describe the import capability of the transmission system. The term "import capability" is defined as the energy that can be transferred into a BA. A BA boundary is specifically defined for each BA by the WECC. Import capability is determined using WECC/North American Electric Reliability Corporation ("NERC") reliability criteria. Accordingly, the system must be capable of meeting all performance criteria for steady state and single contingency outage conditions at the stated import level. Nevada Power's system import capability is dependent on generation dispatch patterns and system loads. Maximum import capability is currently attainable only with the operation of the Clark Generating Station, which provides an injection point in the middle of the Nevada Power system.

Once ON Line is in service, the Companies plan to jointly dispatch the Nevada Power and Sierra systems. Thus the ON Line will be an internal system line. As described above, the Companies are seeking to establish a combined BA with WECC. A post ON Line analysis for the combined BA was performed by creating reliability criteria limited, maximum interface transfer limit cases for the Companies' north and south systems. ON Line was then added, and the cases were re-analyzed to determine any increase or decrease in north or south interface capability of the integrated BA. A summer 2011 case was used for the analysis. Figure TP-4 shows the resulting values. These are the most currently available numbers and they remain under study.

FIGURE TP-4- MAXIMUM SYSTEM IMPORT CAPABILITY WITH COMBINED BA,

NON-SIMULTANEOUS, Non-Economic Dispatch

External Interface:	2012, 2013 Pre ON Line	2014 Post ON Line	Comments
Northern Interfaces	1000 MW	1275 MW	BPA (Path 76), Idaho (Path 16), Utah (Path 32) & PG&E (Path 24)
Southern Nevada Transmission Interface	3937 MW	3939 MW	Path 81, post WECC re-definition
Other	1333 MW	1333 MW	Utah (Path 35) & Crystal (Path 77)

The above system import limits are based on two different generation patterns (one for the northern system and another for the southern system) that allow testing and achieving of the maximum system import capability (i.e., it assumes that the generation internal to the system is used at its workable minimum to meet the system load). This generation dispatch is not based on and generally would be different from "economic dispatch", but it allows achieving a higher system import capability. In a non-transmission limited study, system import is equal to load plus losses minus internal generation, or:

$$\text{import} = \text{load} + \text{losses} - \text{internal generation}$$

Therefore, when all available generating units are being used to serve system load, imports will be equal to the difference between load and generation. Whether the system has the capacity to perform a system wheel (i.e., an import with a corresponding export) under these circumstances is determined through studies, which the Companies routinely complete in response to transmission service requests.

The maximum system import capacity using a typical economic dispatch generation pattern (generating units are backed down in economic order until a system limitation is reached and/or dispatched in a specific manner to avoid known system overloads) is 2,500 MW. As explained in Docket 11-08011, in order to reach the 2,500 MW import limit while avoiding costly transmission system additions, operator actions are required. For example, import through the 230 kV Crystal phase shifters must be increased up to 950 MW and the Clark combined cycle units must be run (up to 375MW) in lieu of the Silverhawk units (i.e. out of economic order). Together with the Chuck Lenzie generation tripping scheme, these actions allow Nevada Power to delay or avoid the following significant transmission system additions:

1. Install a new Harry Allen 1,500 MVA, 500/230 kV autotransformer.
2. Replace Clark Bank #6 with a new 300 MVA, 230/138 kV autotransformer.
3. Install a new Faulkner 300 MVA, 230/138 kV autotransformer (Bank #2).

The cost of these additions was estimated to be $60.7 million excluding AFUDC in Docket 11-08011. The economic analysis provided in Docket 11-08011 showed that use of certain changes in operating procedures (discussed below) are less costly that the transmission additions. Nevada Power continues to expect that it can continue to manage the risks and operate this way in order to further delay these transmission additions.

The critical factor in determining the system import capability is the available transmission capacity between the 500 kV and 230 kV transmission systems, which would be enhanced by the aforementioned additions. By itself, the ON Line project has a very limited impact on the Southern Nevada import capability (see Figure TP-X). Flows on ON Line into Harry Allen result in a corresponding reduction in the amount of generation or system imports that can be delivered into the Harry Allen 500 kV bus because of the 500/230 kV limit both sources would use to deliver into the Las Vegas Valley. However, load growth inside the Las Vegas Valley or removal of generation within the load pocket, if replaced by generation outside the load pocket, has the potential to accelerate the need for future transmission upgrades.

Maximum import capability should not be confused with long-term, firm transmission capability under the OATT. Maximum import capability is measured using maximum load and minimum generation and actual imports are highly dependent on load, generation and available voltage support. Long-term, Firm Transmission Service under the OATT must be available without limits imposed by load variations or other transmission customers' actions.

5. EXPORT CAPABILITY

NAC §704.9385(3)(a) requires that the transmission plan describe the export capability of the transmission system. Nevada Power's system export capability is dependent on available internal generation and system load. Currently, maximum system export capability is limited by the available generation. Export capability is limited to the system's maximum generation minus the minimum load. The numbers in Figure TP-5 below assume adequate generation is available to meet load and export demands.

FIGURE TP-5 - MAXIMUM SYSTEM EXPORT CAPABILITY

2012	2013	2014 (post ON Line)
4176 MW	4176 MW	4465 MW

The export levels for 2012 and 2013 were estimated using a case with maximum flow through the SNTI simultaneously with maximum flow through the NCP (combined Paths # 35 and # 77). The post-ON Line export increase was due to an additional injection into the southern service area through the ON Line, resulting in an increase of the SNTI export capability. In a non-transmission limited case, system export is equal to internal generation minus load and losses, or:

export = internal generation – load – losses

Maximum export capability should not be confused with the Company's long-term, firm transmission capability under the OATT. Nevada Power's maximum export capability is determined using minimum load and maximum generation resources within the system and actual exports are highly dependent on load and generation. Long-term, Firm Transmission Service under the NVE OATT must be deliverable without limits imposed by load variations or other transmission customers' actions.

6. NEVADA POWER'S TRANSMISSION SERVICE OBLIGATIONS

NAC §704.9385(3)(d) requires that the transmission plan identify all existing and proposed transmission service agreements ("TSAs") with transmission customers, the expiration dates of those obligations and their impacts on the transmission capacity available for use by bundled retail customers. Nevada Power is currently obligated to provide transmission service to several transmission customers under TSAs. Existing TSAs are listed in Figures TP-6 and TP-7. Figure TP-6 lists Nevada Power's long term transmission obligations for import into the Balancing Area and Figure TP-7 lists Nevada Power's long term transmission obligations for exports out of the Balancing Area. The impact of these combined TSAs on the amount of import transmission capacity available for use by bundled retail customers is reflected in the Transmission portion of the Load & Resource Tables.

FIGURE TP-6 - NEVADA POWER'S LONG TERM BALANCING AREA TRANSMISSION IMPORT OBLIGATIONS (NETWORK CUSTOMERS)

Agreement	Delivery Interface	Termination
SNWA SB-211	MD230	5/31/2013
LVVWD SB-211	MD230	2/28/2014
City of Las Vegas SB-211	MD230	5/31/2013
City of Henderson SB-211	MD230	5/31/2013

Though the above customers are Network Customers, their load obligations are shown as part of the Balancing Area Customer Load in the L&R Table and on a combined basis in Figure TP-9.

FIGURE TP-7 - NEVADA POWER'S LONG TERM BALANCING AREA TRANSMISSION EXPORT OBLIGATIONS

Agreement	MW	POR – POD	Termination
CDWR RG4	235	Reid Gardner – ELD 500	7/1/2013
Apex-Las Vegas Power Co	225	LS Apex – MD 230	7/30/2023
Apex-Las Vegas Power Co	275	LS Apex – MD 230	7/30/2023
Silverhawk – SNWA	125	Silverhawk – MD 230	4/30/2014
Total	**860**		

NAC 704.9385(3)(e) requires the Company to provide "a table identifying all the transmission capacity that the utility has secured for its bundled retail transmission customers on both its transmission system and the transmission systems of other utilities." This information is provided in Figure TP-8, below.

FIGURE TP-8 - TRANSMISSION CAPACITY SECURED FOR BUNDLED RETAIL TRANSMISSION CUSTOMERS

	Firm Import Capacity Reserved by NVE South Native Load Provider (NEVP)									
Interface	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Mead	355	355	355	355	355	355	355	355	355	355
RedButte	0	0	0	0	0	0	0	0	0	0
McCullough	0	0	0	0	0	0	0	0	0	0
Crystal	260	260	260	260	260	260	260	260	260	260
Eldorado	0	0	0	0	0	0	0	0	0	0
Mohave (Laughlin)	50	50	50	50	50	50	50	50	50	50
	665	665	665	665	665	665	665	665	665	665
	Firm Capacity Reserved by NVE South on Other Systems									
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	0	0	0	0	0	0	0	0	0	0

NAC 704.945(4) requires "a graph or table" that shows "the allocation of the capacity of the transmission system of the utility between bundled retail transmission customers, unbundled retail transmission customers and wholesale transmission customers." This information is provided in Figure TP-9, below.

FIGURE TP-9 - ALLOCATION OF CAPACITY OF TRANSMISSION SYSTEM

Firm Import Capacity for NV Energy SB-211 Network Customers									
2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
86	87	88	89	91	92	94	95	97	98
Balancing Authority Customer Import Capacity									
2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
461	462	471	478	485	492	499	500	499	499

7. RENEWABLE ENERGY TRANSMISSION DEVELOPMENT

(A). CONCEPTUAL RENEWABLE ENERGY ZONE TRANSMISSION PLAN

NAC §704.9385(6), which the Commission adopted in Docket No. 09-07011, requires that every IRP include a conceptual Renewable Energy Zone Transmission Plan ("REZTP") for the 20 years covered by the Energy Supply Plan forecast. The REZTP is provided in Technical Appendix TRAN-1.

(B). RENEWABLE TRANSMISSION INITIATIVE (RTI)

The Renewable Transmission Initiative ("RTI") is a transmission planning process designed to determine if there is sufficient market support for new transmission facilities needed to access Nevada's designated renewable energy zones and deliver the resources to loads to merit permitting and constructing the facilities.

1. <u>Developments That Lead to the Renewable Transmission Initiative</u>

In order to comply with federal initiatives and state mandates to foster the development of renewable energy within the state of Nevada, the Companies have participated in a number of different efforts investigating strategies for developing transmission infrastructure needed to support renewable energy resources. These efforts have included (1) the Company's own RPS development; (2) Nevada's Renewable Energy Transmission Access Advisory Committee ("RETAAC") renewable zone definitions; (3) OATT interconnection requests; (4) responses to state policy makers interested in exporting renewable resources; (5) DOE and U.S. Bureau of Land Management ("BLM") corridor designation processes; (6) Western Governors' Association ("WGA") corridor identification processes; (7) Western Renewable Energy Zone ("WREZ") identification process; (8) BLM lease grant requests; and (9) the BLM's Solar Energy Development Programmatic Environmental Impact Statement ("PEIS") process. These efforts resulted in an MOU with the Western Area Power Administration ("WAPA") and the filing of the Renewable Energy Conceptual Transmission Plan ("RECTP") in the Sierra Pacific Power Company 2010 Integrated Resource Plan, Docket in Docket 10-07003.

AB 387, enacted by the 2009 Nevada Legislature, requires:

> the utility to include in its plan a plan for construction or expansion of transmission facilities to serve renewable energy zones *and* to facilitate the utility in meeting the portfolio standard established by NRS 704.7821. (Emphasis added.)

The Commission accepted the RECTP as meeting the requirements of AB387 and the regulations adopted by the Commission in Docket 09-07011 on the development of transmission facilities to serve renewable energy zones. The RECTP included a strategy for developing a robust, flexible and scalable bulk transmission system to interconnect the generation forecasted by RETAAC for each of the renewable energy zones. In compliance with NAC 704.9385 Nevada Power is also for the first time providing a Renewable Energy Zone Transmission Plan ("REZTP"). Because of the conceptual nature of the plan, the fact that the Companies are not asking for Commission approval of any of the facilities in the plan, and because the PUCN defined renewable energy zones have not changed, the REZTP is the same plan (the RECTP) that was approved by the Commission as part of Docket 10-07003 with data tables updated. The REZTP is included in the Technical Appendix TRAN-1.

The Companies are not requesting approval of any of the potential transmission facilities at this time, including the facilities that are the subject of the RTI. All of these potential transmission projects are in the planning/development stages only.

2. The Nature of the Renewable Transmission Initiative

The RTI was the next logical step, building on the RECTP, for the Companies to take in order to promote the construction of transmission facilities to support the development of Nevada renewable energy while also minimizing financial risk to ratepayers. The Companies' current process to provide transmission to markets is driven by individual requests from project developers that result in transmission facilities that are either too expensive for one project to bear alone or do not result in an economically efficient expansion of the transmission system.

The RTI is not a transmission project the Companies have proposed to construct. Rather, it is an integrated renewable resource and transmission *planning process* designed to support the development of renewable energy resources within the state. The purpose of the RTI is to enable the Companies to determine the level of market interest in the development of the transmission infrastructure necessary to access Nevada's identified renewable energy zones through participant-funded transmission facilities, which minimizes ratepayer risk. The Companies designed the RTI as a multi stage planning process intended to consolidate long-term stakeholder interests and limit initial financial commitment while determining the level of market interest in funding transmission development.

The Companies developed RTI corridors based on the previous study work, including RETAAC and other stakeholder groups, regional planning groups, and the Companies' RECTP. The selected corridors provide Northern and Southern market access to the Nevada renewable energy zones that contain the highest development potential. The selected corridors provide access to over 80% of the renewable potential identified by RETAAC. The Companies completed extensive work on identifying RTI corridors and submitted an SF299/Preliminary Plan of Development to the BLM on May 5, 2011.

3. The RTI Process

The multi-stage nature of the RTI is best illustrated by the step-by-step process developed and implemented by the Companies:

(1) Issue public announcement of the RTI and solicitation of indicative statements of interest;

(2) Conduct pre-submittal information conferences;

(3) Submission of indicative statements of interest by market participants; then

(4) Communicate with market participants about the cluster in which individual transmission service statements of interest will be studied and estimate of each RTI participant's pro rata share of study costs;

(5) Perform system impact study using "clustering" technique;

(6) Report results of study process, including calculation of market participants' portion of permitting costs;

(7) Obtain Notices of Intent from RTI participants who intend to continue their participation through the next phase of the RTI;

(8) File with the Federal Energy Regulatory Commission ("FERC") a request that FERC issue a Declaratory Order authorizing NV Energy to among other items, assign to, and collect from, RTI participants certain costs (including permitting and right of way acquisition costs) in exchange for certain capacity rights over the proposed facilities; and simultaneously

(9) Submit the proposed transmission facilities to the Commission for Resource Planning approval;

(10) Subject to FERC approval, obtain financial commitment from market participants for pro rata shares of development and permitting costs;

(11) Subject to FERC approval, market participants to secure capacity rights in exchange for funding said development and permitting activities;

(12) Permitting and right of way acquisition;

(13) Refine transmission studies and costs;

(14) Execute Transmission Service Agreements and securitize market participant's pro rata share of facilities' construction costs and TSA fees; then

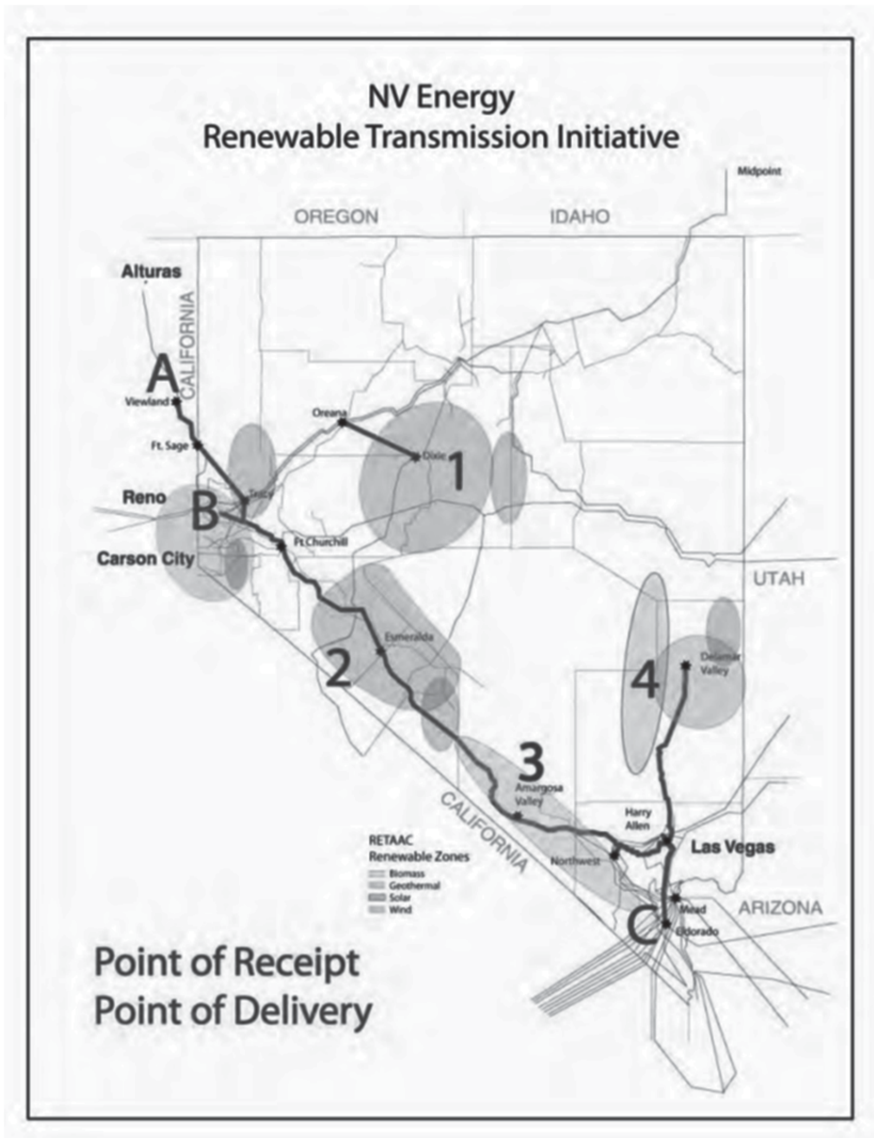
(15) Results of studies, costs and financial commitments submitted to Commission and FERC for approval; and finally

(16) Construction.

The Companies completed Steps (1) through (6).

The Companies initiated the RTI with the issuance of a Solicitation of Interest in June of 2011 to engage renewable developers, load serving entities and others to assess their interest in obtaining transmission service from Nevada's identified renewable energy zones to electric loads in other markets. In the Solicitation of Interest, the Companies requested that market participants express their interest in exporting renewable energy from any of four specified Points of Receipt ("POR") on the Companies' systems to any of three specified Points of Delivery ("POD"). The corridors that result from the pairing of PORs to PODs are those that were included in the Preliminary Plan of Development. Figure TP-10 shows the RTI with PORs numbered 1 through 4 and PODs numbered A through C.

FIGURE TP-10 - RENEWABLE TRANSMISSION INITIATIVE MAP



The Companies held pre-submittal information meetings for interested entities on August 10, 2011 in Las Vegas and August 12, 2011 in Reno. Following the pre-submittal informational meetings, the Companies received Statements of Interest ("SOIs") in October, 2011 from over 50 participants, with expressed interest of exporting in excess of 5,000 MW of renewable energy. Based on the SOIs received, the Companies designed a System Impact Study ("SIS") to determine the facilities and estimated costs necessary to provide transmission service of the PORs to the PODs identified in the SOIs.

Of those RTI participants that submitted SOIs, only a subset of participants elected to continue with the study phase of the RTI project. With the subset of RTI participants who elected to proceed to the study phase, the Companies performed the SIS to determine the facilities and estimated costs necessary to provide transmission service from PORs 1 (Dixie) and 2 (Esmeralda) to POD C Eldorado. The SIS costs were funded by the RTI participants. The SIS determined that a hybrid option using both 345 kV and 500 kV facilities between the northern and southern systems was most cost effective, based on deliverability and costs. Confidential Figure TP-11 is a one-line diagram of the RTI facilities that were the subject of the SIS.

In Docket 11-06015, Investigation Regarding the Renewable Transmission Initiative, the Companies provided the Commission copies of RTI-related documents and correspondence. The documents provided to the Commission included all submitted SOIs, customer notifications regarding the cost and scope of proposed transmission studies, and executed System Impact Study Agreements entered into by RTI participants. The Companies filed these documents with the Commission under seal and requested that they receive confidential treatment, because they contain confidential information, the disclosure of which would cause competitive harm to the various participants who submitted SOIs. All documents filed under 11-06015 are included in this filing as Technical Appendices TRAN-2, TRAN-7 (Redacted) and TRAN-8 (Redacted).

The completed SIS was provided to RTI participants on April 27, 2012. Discussions addressing the SIS results and the next phase of the RTI were held with all RTI participants who participated in the SIS phase. In addition, the Companies requested each RTI participant to indicate if they wished to move forward to the next phase.

Based on customers' responses, the NV Energy Renewable Transmission Initiative ("RTI") has been concluded. Customer commitments to fund the Phase 2 permitting and Right of Way acquisition were insufficient to proceed as an aggregated customer-driven transmission development process at this time. Remaining customer(s) have been informed they may submit individual project requests for Point-to-Point Transmission Service under the NV Energy Open Access Transmission Tariff ("OATT") if they desire to continue their project(s). NV Energy will be considering appropriate next steps to transmission development for renewables in Nevada.

4. RTI Costs

To date, the Companies have incurred costs of approximately $150,000 for third-party services related to the RTI. The costs incurred to perform the SIS for the RTI were funded by RTI participants. If RTI participants had elected to move forward with the permitting phase of the RTI process, the Companies would have requested to collect necessary funds from those requesting to move forward in the RTI process subject to making and obtaining approval from the Commission and FERC.

FIGURE TP-11- (REDACTED) NV ENERGY PREFERRED RTI TRANSMISSION DIAGRAM

8. SPECIFIC REQUESTS FOR COMMISSION APPROVAL

NAC §704.9385(3)(b) requires that the transmission plan include a description of transmission projects that the Company is considering to expand or upgrade its transmission facilities. The Company is not requesting funds for new expansions or upgrades to its facilities in this Plan. Action Plan approval is being requested for expenses for regional planning requirements associated with West Connect membership, as well as revisions to schedules and budgets of previously approved project budgets where set forth below.

(A). WESTCONNECT

NAC §704.9385(3)(f) requires that the Company describe its participation in regional planning organizations, as well as the role of these organizations in the Company's transmission planning activities. Nevada Power and Sierra are members of the WestConnect Steering Committee and WestConnect Transmission Planning Committee, and are seeking Commission authorization to fund the continued participation in WestConnect during the 2013-2015 Action Plan Period (this assumes that NV Energy remains part of WestConnect if all issues related to FERC Order 1000 are resolved in a manner that is in the best interests of NV Energy's customers). The Action Plan budgets for WestConnect participation have increased due to the mandates of FERC Order 1000. Nevada Power's share of these costs is estimated as $146K in 2013, $150K in 2014, and $154K in 2015).

The descriptions below are for the current WestConnect structure. As part of Order 1000 work WestConnect likely will change its various committees and organizational structure. The Commission is either monitoring or participating in WestConnect's Order 1000 discussions as a stakeholder.

FIGURE TP-12 - WESTCONNECT MAP

WestConnect Steering Committee

The WestConnect Steering Committee is a group of 17 Transmission owners in the Western Interconnection who have joined together under a Memorandum of Understanding ("MOU") for the following purposes:

- Continue investigation of feasibility of cost-effective wholesale market enhancements.
- Pursue required regulatory approvals for enhancements.
- Work cooperatively with other western grid organizations and market participants.
- Address seams issues in appropriate forums (e.g. WECC Seams Issues Subcommittee).

WestConnect Transmission Planning Committee

The WestConnect Planning Committee is a group of 17 Transmission owners in the Western Interconnection who have joined together under an MOU in order to comply with the FERC Open Access Transmission Tariff--Attachment K--Transmission Planning Process requirements and guidelines set forth in FERC's requirements stated in Order No. 890, *et al*.

WestConnect is currently working on the following projects:

- Implementation of FERC Order 1000
- Regional Pricing Experiment[19]
- Regional Transmission Planning
- Virtual Control Area Investigation & ACE Diversity Interchange
- New Transmission Products
- Investigation of Large Generator Interconnection Procedures

Figure TP-13 summarizes Nevada Power's and Sierra's expected total annual costs for WestConnect.

FIGURE TP-13 - WESTCONNECT ESTIMATED COSTS
(thousands, excluding AFUDC)

WestConnect	2013	2014	2015	3-Year Total
Nevada Power Share	$ 146	$ 150	$ 154	$ 450
Sierra Share	$ 73	$ 75	$ 77	$ 225
TOTAL Companies	$ 219	$ 225	$ 231	$ 675

[19] Although WestConnect continues to work on the Regional Pricing Experiment, Nevada Power has opted out of the program because none of its customers chose to participate.

An additional $100,000 was added each year in the action period for FERC Order 1000 related increases. The actual increase is unknown at this time.

9. FUTURE PROJECTS—NO APPROVAL REQUESTED FOR ACTION PLAN PERIOD

The following provides a description of potential transmission projects for which funding requests fall outside the 2013-2015 Action Plan Period. These projects are described here in order to provide the Commission with an update on the issues and developments that are expected to trigger a need for these transmission additions in the future. The Company will request Commission approval of the costs of developing and/or completing the projects described below as appropriate through future IRP filings.

(A). HARRY ALLEN 500/230 KV TRANSFORMER ADDITION

As discussed above, the critical factor in determining the maximum system capability is the transmission capacity between the 500 kV and 230 kV transmission systems. With this in mind, the Company previously requested and received Commission approval to permit and/or construct the following 500/230 kV transformer additions in Docket Nos. 06-0120 and 06-06051):

(1) the Sunrise 500/230 kV Substation and associated 230 kV and 138 kV infrastructure;
(2) the Thunderbird 500/230 kV Substation; and
(3) the Northwest Substation 2nd 500/230 kV Transformer with the Harry Allen – Northwest 500 kV transmission line.

In the Company's last IRP (Docket 10-07003), Nevada Power requested authority to delay the in-service dates for these projects due to the reduction in forecast load growth. The Commission approved the new in-service dates proposed by the Company and approved expenditures required to keep these projects viable. Because the construction and system need for the projects were scheduled to be outside the 2010-12 Action Plan Period, the Commission ordered the Company to re-submit the projects for IRP approval at a later date.

The anticipated in-service dates for the Sunrise, Thunderbird and Northwest projects continue to be delayed, and are currently well outside the 2013-2015 Action Plan Period. While Nevada Power is not seeking approval of any of the listed projects at this time, recent analysis shows that a Harry Allen 500/230 kV transformer addition is preferred over either the Sunrise or Thunderbird projects. With the current load forecast and topology for Las Vegas, the Harry Allen transformer addition provides better performance at a lower cost.

The Company is not seeking approval to construct the Harry Allen 500/230 kV transformer addition in the 2013-15 Action Plan period. The Company conducted analyses to determine whether it would be more cost effective to install or delay the transformer and rely instead on operating procedures until other factors drove the need for such transformer. An analysis was made of the system import capability with the Harry Allen 500/230 kV transformer as compared to changes in operating procedures. The results of such analysis are provided below. The conclusion of those studies (discussed below) effectively delays the need for any transmission upgrade that would bring bulk energy into the Las Vegas load pocket. Given the ability to continue to mitigate operational risks as outlined below, the trigger(s) for a significant transmission addition are now:

(1) substantial increase in load growth;
(2) replacement of generation inside the Las Vegas load pocket with generation outside the load pocket;
(3) new Transmission Service Agreements; and
(4) the addition of renewable generation into the northwest of Las Vegas and/or in the Armargosa Valley seeking deliveries inside the Las Vegas load pocket.

Although the Company cannot accurately predict the timing of any of these triggers at this time, none are currently anticipated to fall within the 2013-2015 Action Plan period.

<u>Transmission System Import Capacity Analysis and Results</u>
The power flow case used to evaluate the system import capacity with economic dispatch order included BA load of 6,098 MW plus approximately 155 MW of losses. This forecast includes coincident combined loads in the BA for transmission customers of 474 MW. ON Line was assumed to be in-service[20] with a 700 MW North to South flow, and Centennial Generation (Chuck Lenzie, Apex, Harry Allen CC and Silverhawk) was set at maximum output in accordance with the economic dispatch order.

Initially the above power flow case was run with 1,500 MWs of NPC BA imports without using the Crystal PST to redirect power from the Harry Allen 500 kV bus to the Harry Allen 230 kV bus. For this case, load was served primarily by Higgins, Chuck Lenzie, Harry Allen, Silverhawk, Reid Gardner, renewable contracts and system imports including Hoover, Navajo and renewable resources scheduled via ON Line. The results of the case showed several overloads during normal operation and multiple elements overloaded during N-1 outage conditions. The results of the cases are shown in the Power Flow Plots in Technical Appendix TRAN-3.

To mitigate the overloads the case was rerun using the Crystal PST to move 950 MW from the Harry Allen 500 kV bus to the Crystal 500 kV and 230 kV buses for injection into the Harry Allen 230 kV bus. Additionally, the Chuck Lenzie Generation RAS was put in place. The Chuck Lenzie Generation RAS is described in Technical Appendix

[20] The delay of the ON Line project makes no difference to transmission import capability.

TRAN-4. The results of this case are also set forth in TRAN-3 and still showed several overloaded elements.

The analysis demonstrates that the Nevada Power transmission system is not currently capable of delivering 6253 MW of BA load plus losses while following the economic dispatch order for NPC generation with 1,500 MW of system imports from the 500 kV system into the Las Vegas load pocket. To alleviate these overloads it was necessary to use the Crystal PST and to operate either Clark or Sunpeak (at Sunrise Station) generation in lieu of Centennial generation out of the economic dispatch order. The results of this case are also shown in TRAN-3.

The power flow studies show that the following actions relieve the remaining N-1 overloads:

- The Crystal PST is operated at 950MW during either high import or high load periods;
- 270 MW of Clark combined cycle generation run with Silverhawk output reduced by the same amount; and
- The Chuck Lenzie Generation RAS is in service

These actions were effective in relieving N-1 overloads, but result in increased system losses (by up to 20 MW) and necessitate operating generation out of economic order.

The analysis was repeated increasing the area import from 1,500 MW to 2,500 MW. Since the load was not changed the increase in system imports required a corresponding 1,000 MW reduction in generation. The results of this case were similar to the previous case. To relieve emergency overloaded elements the following actions were required:

- The Crystal PST is operated at 950MW during either high import or high load periods;
- 375 MW of Clark combined cycle generation was run with Silverhawk output reduced by the same amount; and
- The Chuck Lenzie Generation RAS is in service

The critical factor in determining the amount of non-economic generation that is required to relieve these overloads was the amount of power transferred into the 230 kV transmission system from the 500 kV transmission system. It made little difference whether such power was coming from Nevada Power-owned generation located on the 500 kV transmission system or from additional system imports being delivered over the 500 kV or 230 kV Southern Cut Plane.

Nevada Power's transmission planning group has performed additional analyses to determine the transmission system additions required to relieve these overloads if the Clark and/or Sunpeak generation are not operated and the Crystal PST is not operated to move 950 MW into the Harry Allen 230 kV bus. The results of these studies show that the following transmission additions would be required:

- Install a new Harry Allen 1,500 MVA 525/230 kV autotransformer; the estimated cost of this addition is $46.1 million excluding AFUDC.
- Install a new 300 MVA 230/138 kV autotransformer at Clark Substation to replace the existing smaller Clark Bank 6; the estimated cost of this addition is $7.2 million excluding AFUDC.
- Install a new 300 MVA 230/138 kV autotransformer at Faulkner Substation (new Bank 2); the estimated cost of this addition is $7.4 million excluding AFUDC.

As shown in Docket No. 11-08011 (see TRAN-5), the total cost of the required transmission additions is $60.7 million excluding AFUDC (2011 dollars). The analysis shows that until additional needs arise, it is less costly to operate with the Crystal PST and Clark generation re-dispatched than to install the required transmission additions at this time. Note: the costs in this filing were not updated from Docket 11-08011 because further studies will refine the scope and cost of any facilities that may be requested in future Resource Plan or Amendment filings.

The transmission upgrades described above have the advantage of not requiring uneconomic dispatch or increased losses caused by sub-optimal Crystal PST settings. Additionally, the Chuck Lenzie unit dropping RAS could be eliminated. These transmission additions would provide more margin for the reliable operation of the transmission system, reduce the probability of major system outages and provide for less complicated system operation, thereby reducing the chances of operator error. However, Nevada Power believes it can continue to manage these risks for the time being. It is likely that these transmission additions will be required at some point in the future. The timing of these additions may be accelerated by certain new service obligations (under new TSAs), additional load growth, or the removal of generation located within the load pocket if that generation is replaced by resources outside the load pocket.

Changes in Operating Procedures

In Docket 11-08011, the 2nd Amendment to Nevada Power's 2009 IRP, Nevada Power described changes in operating procedures that had allowed the Company to delay significant transmission upgrades required to move bulk energy from the 500 kV system into the Las Vegas load pocket. Although the focus of the discussion in that filing was the retirement of the Sunrise Units, the Company demonstrated that with the use of the Crystal phase shifting transformer (the "Crystal PST"), a Chuck Lenzie generation tripping remedial action scheme ("Chuck Lenzie Generation RAS"), and uneconomic dispatch of generation (the Clark combined cycle units in lieu of Silverhawk generation) the Company could continue to delay future 500/230 kV transmission upgrades. Nevada Power further demonstrated that additional retirement of generation within the Las Vegas load pocket, if replaced by generation outside the load pocket, will trigger the need for 500/230 kV transmission upgrades and that it makes little difference whether power is coming from Nevada Power owned generation located on the 500 kV transmission system or from additional system imports being delivered over the 500 kV or 230 kV transmission systems. Technical Appendices TRANS-1, 2 and 3 from the Second

Amendment filing are reproduced here as Technical Appendices TRAN-3, 4, and 5 for reference.

The results of the system import capacity analysis described earlier show that the BA maximum import capacity is 2,500 MW, assuming Crystal PST operation at 950 MW, the Chuck Lenzie Generation RAS and redispatch of Centennial generation. (Note: there have been no changes in system conditions since the last filing that would impact the outcome of the analysis provided in Docket 11-08011). Therefore, the operating procedures currently represent a more economical option than the addition of the referenced transformer.

(B). SOLAR PARTNERS XI, LLC (BRIGHT SOURCE) LARGE GENERATION INTERCONNECTION AGREEMENT ("LGIA")

The Company has entered into an LGIA with Solar Partners XI, LLC for a 440 MW Net Solar Thermal facility interconnection to the Crystal 230 kV line. This LGIA includes Network Upgrades of $5.6M for a 8.6 mile 230 kV line addition between Crystal and Harry Allen Substations. However, the customer has placed the contract in suspension and no expenditures are planned through the Action Plan period.

(C). CONTINUED DEVELOPMENT OF HARRY ALLEN-ELDORADO TRANSMISSION CORRIDOR

The Company intends to continue strategic development of the Harry Allen–Eldorado transmission corridor. Any construction that might eventually result from this corridor development effort is expected to fall outside the 2013-2015 Action Plan Period, so the Company is not requesting funding for this activity at this time. If in the future the Company decides to go forward with a project or request rate recovery of costs associated with this development effort, the Company will file an amendment to the Resource Plan specifically requesting Commission approval and cost recovery.

10. PREVIOUSLY APPROVED TRANSMISSION PROJECTS DELAYED OF DEFERRED

Below is an update of projects that were approved by the Commission in the 2006 IRP, the 2009 IRP, or in subsequent IRP amendment filings.

(A). ON LINE

Together with Sierra, in Docket No. 10-02009, Nevada Power requested and received Commission approval to proceed with construction of the 235-mile long 500 kV ON Line through a joint venture arrangement with Great Basin Transmission, LLC ("Great Basin"). The ON Line was proposed to be in-service by December 31, 2012. The IRP approved budget was $509.6 million, excluding AFUDC.

After receiving Commission approval, Sierra and Nevada Power (collectively the "NVE Parties") and Great Basin entered into a Transmission Use and Capacity Exchange Agreement ("TUA") with an effective date of August 20, 2010. The Commission approved the TUA on November 19, 2010. On February 10, 2011, Great Basin assigned 100% of its interest in ON Line to its affiliate Great Basin Transmission South, LLC ("GBT-South"). On February 11, 2011, the parties completed the financial transaction when GBT-South sold and the NVE Parties purchased undivided ownership interests in the ON Line, with Nevada Power purchasing a 23.75% interest and Sierra purchasing a 1.25% interest. Together, GBT-South and the NVE Parties are referred to below as the "Owners."

Current Status

Progress on construction of the transmission line through May 2012 is summarized as follows:

Activity	% Complete
Environmental Survey	100%
Construct Roads and Pads	99%
Precast Foundation Install	95%
Anchor Install and Testing	95%
Structure Haul	87%
Structure Assembly	76%
Structure Erection	Suspended at 15% complete
String Conductor	Suspended at 15% complete

The following paragraphs discuss the status of (a) cultural inventory and Construction, Operation and Maintenance ("COM") Plan[21] deviation requests, which initially delayed the early phases of transmission line construction; (b) construction activity on other project components; and (c) the issues that caused the Owners to suspend structure erection and the stringing of conductor.

Cultural Inventory and COM Plan Deviation Requests

Construction of the ON Line 500 kV transmission line started in April 2011. Due to issues with the cultural inventory and implementation of the COM Plan, early construction of ON Line progressed at a much slower pace than originally anticipated. Initial schedule delays were the result of the need to prepare and obtain approval of numerous COM Plan Deviation Requests for the contractor to:

1. Avoid impacts to a substantial number of newly identified cultural sites in the current work area between the proposed Robinson Summit Substation and Harry Allen substation;
2. Avoid nesting birds in accordance with the Migratory Bird Treaty Act;

[21] The COM Plan is required by the BLM and must be approved prior to receiving a Notice to Proceed. The COM Plan defines work areas and specific mitigation requirements along the entire route.

3. Relocate approved COM Plan access roads to facilitate safer and more efficient construction (request to relocate the centerline travel route from the center of the Right-of-Way to the edge); and
4. Widen two-track access roads identified in the COM Plan as "Existing Unpaved Roads Not Requiring Improvement" to facilitate access for heavy equipment.

This work resulted in approximately 130 COM Plan Deviation Requests which had to be submitted to and approved by the BLM. In addition, the project suffered certain contractor delays in 2011 attributable to a number of other factors including contractor-requested COM Plan Deviation Requests and late delivery of Owner-furnished and Contractor-furnished materials.

On September 30, 2011, the BLM approved the Owners' request to modify the COM Plan to allow the Companies to begin to install overhead wires in seasonally restricted wildlife habitat (winter restrictions occur between November 1 and April 15). This approval would have provided additional time for the contractor to make up some or all of the progress lost since the start of construction. The installation of overhead wires started on October 17, 2011, but was halted in January 2012 for the reasons set forth below under the section entitled "Wind-Induced Vibration Issues."

Construction Activity

While technical solutions are being identified and tested to address damage to tubular steel guyed-V towers caused by wind-induced vibration, the Companies have continued to proceed to construct some project elements (*e.g.,* construction of roads and pads, installation of foundations and anchors, build-out of communication sites and the Robinson Summit terminus of the line), and have deferred progress on other project segments (*e.g.,* construction of the Harry Allen terminus, 345 kV additions at Falcon Substation, and installation of electronic equipment at microwave and fiber optics sites used for communication). Decisions to proceed with or defer work on discrete components of the project have been made based on assessments of both physical requirements and contractual commitments. This effort has been focused on managing cash flows and project schedule pending resolution of the technical challenges facing the project. For example:

- Construction of roads and pads, precast foundation installation, anchor installation and testing continues and is expected to be complete before the end of July 2012. In addition, structure hauling and structure assembly is continuing and is expected to be complete before the end of September 2012.

- Construction at Robinson Summit Substation started on June 1, 2011. A majority of the below-grade and above-grade civil work is complete and, overall, the substation is approximately 65% complete. Major equipment has been ordered and is scheduled to be delivered in the second and third quarter of 2012. Design of the Harry Allen 500 kV terminal addition is complete and most of the construction has been deferred into 2013. Major equipment for this substation has been ordered and is scheduled to be delivered and stored onsite in the second and fourth quarter of 2012.

- Construction on the telecommunication facilities (microwave and fiber optic amplification sites) for ON Line started on February 6, 2012 and civil/electrical construction is progressing on schedule. All electronic equipment for the communication sites has been purchased, tested and packaged for shipment. Installation of electronic equipment in most of the microwave and all of the fiber optic sites has been deferred to the first and second quarter of 2013.

- Design of the Falcon-Gonder 345 kV line fold into Robinson Summit Substation is complete and construction is scheduled to start in the first quarter of 2013. Most of the major material is available from a cancelled Sierra 345 kV project, or has otherwise been ordered and is scheduled to be delivered in the first quarter of 2013. Design of the Falcon Substation additions is on schedule and civil construction is scheduled to start in the third quarter of 2012. Major equipment has been ordered and is scheduled to be delivered and installed in 2013.

Wind-Induced Vibration Issues

Around the first of December 2011, high sustained winds were experienced in Eastern Nevada in the area of construction. Crews working on the project observed damage to several of the tubular guyed-V towers after the winds subsided. The Owners directed construction crews to undertake immediate measures to ensure safety and assess the damage. The cause of the damage has been since attributed to wind-induced vibration experienced when the tubular guyed-V towers are exposed to sustained winds from various directions.

On February 3, 2012, the Owners announced at least a three-month delay in the in-service date of the ON Line project to determine the cause of and address the wind-induced vibration issues. Since then, the Owners have taken down most installed tubular guyed-V towers not supporting conductor, installed temporary mitigation measures on those structures supporting conductor, and have undertaken other measures to ensure safety and gather information necessary to assess the cause and extent of the damage and identify potential mitigation solutions to ensure the long-term viability of the project.

Efforts to address the wind-induced vibration issues are extensive and continuing. Assisted by industry experts, the Owners are analyzing different mitigation measures to safely and cost-effectively address the wind-induced vibration observed in the structures. Following extensive wind tunnel testing and dynamic structure modeling, a set of potential structural modifications and solutions for cost effectively mitigating damaging wind-induced vibrations has been identified. Identified measures are now being subjected to extensive engineering analysis and field testing. Field testing of the alternative mitigation measures continues both at the project site (using towers that were already in place when wind-induced vibration damage was observed) and at an offsite research facility where sustained winds at different velocities and from different directions are typical. More specifically, Finite Element Analysis[22] of data collected from these sites is being used to evaluate the stress distributions and concentrations in these towers. Additionally, the engineering analysis includes structure response models that will be used to predict stress concentration levels for the full range of wind speeds that the tubular guyed V towers are designed to withstand. At this time, the Owners do not anticipate recommencing installation of tubular guyed-V towers for the ON Line project until all computer analysis, wind tunnel testing, and field testing of mitigation measures have been completed and the results have been analyzed to ensure safety and reliability of the structures under all reasonably anticipated wind conditions.

Schedule Revisions

As mentioned above, the Owners are testing several different tower modifications using several different testing techniques. Data gathered from computer modeling, wind-tunnel and field testing is currently being analyzed. Engineering experts from Thomas and Betts ("T&B"), the tower supplier, are expected to deliver their draft report to the Owners in early July 2012. That information will be subject to review by the Owners and Owners' experts, and a final report from T&B is currently expected by the end of July 25, 2012. The Owners' independent experts, Cermak Peterka Petersen ("CPP"), are expecting to issue a separate report and recommendation by the end of July 2012. The CPP report, along with T&B's final report and CPP's critique of the T&B report, will be reviewed by the Owners and assist the Owners in reaching a determination of an appropriate course of action for the project. The results of the Owners' determinations will be provided to the Commission as soon as possible thereafter in the form of supplemental testimony and/or exhibits filed in this 2012 IRP. A decision by the Commission approving revisions to the project on or before December 31, 2012 will support a December 31, 2013 completion date.

Budget Revisions

Work on potential mitigation measures has progressed to the point that a revised budget has been prepared reflecting updated costs to complete the ON Line project. The revised budget is based on information known as of the date of the filing and is subject to further revision based on the outcomes of the various testing and engineering analyses currently under way and described above. The revised estimated cost to construct the ON Line, without AFUDC, is $552.1 million, an increase of $42.5 million or 8.34 percent over the original $509.6 million (without AFUDC) IRP-approved budget. The revised budget incorporates current estimates of the cost of the most promising and cost-effective mitigation measures identified to date. As of May 31, 2012, the Owners had spent approximately $296.9 on the ON Line project. The NVE Parties' 25% ownership share of the total was approximately $74.2 million.

[22] Finite Element Analysis or "FEA" uses computer simulation to map a structure using nodes and mesh to determine how the structure will react to varying load conditions.

FIGURE TP-14 – (REDACTED) ON LINE TOTAL ESTIMATED COSTS

Project	Prior	2013	2014	2015	3 Yr Total	2016-2020	TOTAL
ON Line 500 kV Transmission Line							
Robinson Summit 500/345 kV Substation							
Harry Allen 500 kV Line Terminal							
Sierra 345 kV Interconnection Facilities							
Nevada Power Communication Facilities							
Sierra Communication Facilities							
Total	$380.8	$169.1	$0.5	$1	$170.3	$1.0	$552.1

<u>Updated Resource Planning Analysis</u>

Given the timing of the 2012 IRP, the Companies seek to utilize this proceeding both to update the Commission on the status of the ON Line project, and to seek Commission approval of the revisions to the project budget and schedule. This unusual request is driven by GBT-South's commitments to the U.S. Department of Energy ("DOE"), which is providing financing support for GBT-South's share of the cost to construct the ON Line. GBT-South has indicated to the NVE Parties that due to its DOE guaranteed loan, it would not be viable to wait to file a stand-alone IRP amendment after the ON Line budget, schedule and determinations regarding the appropriate course of action are finalized. Therefore, while the information and analysis prepared and filed on June 29th in this 2012 IRP are necessarily based on progress to date, the Companies propose to file an update of any material changes to the information or analysis presented here once the Owners make appropriate determinations regarding the status of the project (most likely in September 2012).

Because the schedule and budget have been revised, the Companies have prepared two different types of analyses to confirm the reasonableness of a decision to proceed with the ON Line.

First the Companies looked at ON Line sunk costs as of two different decision dates—September 1, 2012 and January 1, 2013. The analysis does not attempt to quantify or reflect any potential legal or settlement costs or claims filed by or against the NVE Parties. A summary of the results analysis is shown below in Figure TP-15 – On Line Sunk Cost Estimate.

FIGURE TP-15 - ON LINE SUNK COST ESTIMATE
(in $1,000)

Decision Date	Actual Expenses through April 30, 2012	Estimated Costs from May 1, 2012 to Decision Date	Estimated Costs for Removal, Salvage, and Reclamation	Total
September 1, 2012	**272.5**	**92.7**	**106.2**	**471.4**
January 1, 2013	**272.5**	**104.9**	**109.5**	**486.9**

The sunk cost analysis shows that together with costs to remove, salvage revenues and reclamation costs, commitments through September 1, 2012 total $471.5 million or 85.4 percent of the revised estimated cost to construct. Commitments through January 1, 2013 are projected to total approximately $487 million or 88.2% of the revised estimated cost to construct. This analysis will be used to inform the Owners' determinations regarding project viability in conjunction with the assessment of the technical experts. The complete sunk cost analysis is attached to Mr. Berdrow's prepared direct testimony.

The Company also prepared a traditional resource planning analysis to determine the present worth of revenue requirement ("PWRR") benefit of proceeding with the ON Line given the revised schedule and budget. The PWRR analysis was created using the most current resource planning inputs (i.e. load forecast, purchased fuel and power costs, carbon and Greenhouse Gas costs, cost of renewables, etc.) utilized to prepare the Preferred and Alternative cases described below in the Economic Analysis section. The analysis required running three sets of production costs: one with the ON Line in service on December 31, 2013, and two without the ON Line and utilizing alternate renewable portfolio build outs. The alternate plans locate incremental renewable resources in Southern Nevada—one plan using Concentrated Solar Power ("CSP") (i.e., thermal solar), PC and wind; the other plan with only PV and wind. The difference in production costs between the scenarios demonstrates the production cost benefits of the ON Line under two different renewable build out scenarios, assuming current economic conditions and forecasts. The analysis also required the preparation of different Capital Expenditure Recovery ("CER") reports: one with the ON Line at the revised budget and one without the ON Line. The values from the two resource planning analyses (production cost plus CER) were then combined to determine the present worth of revenue requirement of the ON Line project. The result is ON Line provides a thirty-year net PWRR benefit of $50 million for Plan Y (solar PV with wind) and $90 million for Plan X (CSP with wind and PV). The full PWRR analysis for each case is included as a Technical Appendix ECON-28 and ECON-29.

The results of the sunk cost analysis confirm the economic reasonableness of a decision to proceed with constructing the ON Line, assuming satisfactory resolution of the wind-induced vibration issues. A decision to terminate the project in either September or December 2012 would cost between 85.4 and 88.2 percent of the revised total budget and provide zero benefits to customers. The results of the conventional resource planning analysis confirm that while the economic benefits of the project have changed since the Commission's Order in Docket No. 10-02009, the project still provides a net positive PWRR benefit. Utilizing the revised budget, proceeding with the ON Line is projected to provide net positive PWRR benefits in the range of at least $50 to $90 million. Again assuming satisfactory resolution of the wind-induced vibration issues, it is reasonable to proceed with constructing the ON Line with the revised budget and according to the revised schedule.

Moreover, the benefits of directly interconnecting the Nevada Power and Sierra systems are *at least* as important now as they were when the project was originally proposed. As set forth in Docket No. 10-02009, the benefits of the ON Line include:

- Facilitating further development of the full menu of renewable energy resources located within Nevada-- primarily geothermal and wind in the North and solar in the South. Without a direct transmission interconnection between the Sierra and Nevada Power systems, development of renewable resources in the North will either stall until some other new transmission solution is built to relieve the Sierra system from oversaturation, or these cost-effective native resources will be exported through the Sierra system and used by other states in meeting their renewable needs.

- By providing for joint dispatch of the two systems, a direct transmission interconnection will allow both customers of both Companies to utilize the most economical mix of renewable and conventional resources, including natural gas transportation assets, without being constrained by geography or physical limitations.

- The joint dispatch opportunities created by a direct transmission interconnection also will reduce costs to customers by incorporating planning for and service to intermittent resources into both the Sierra and Nevada Power systems.

- A direct transmission interconnection of the Sierra and Nevada Power systems will provide direct operational savings through load diversity—the coincident peaks of the two systems together are less than the sum of the coincident peaks of the two systems separately. With load diversity, planning reserve margins and operating reserve sharing obligations are reduced.

- With a direct transmission interconnection between Nevada Power and Sierra, each system will be able to support the other during outages and other events, improving the reliability of both systems.

- A transmission interconnection between the Sierra and Nevada Power systems will provide an invaluable hedge against climate change policy. To the extent that investment in the ON Line fosters the development of all types of renewable resources located here in Nevada, it eases the cost burden of meeting potential climate change regulations for customers.

Many of the above-identified benefits are captured at least in part by the PWRR analysis. However, not all of these benefits can be reflected through production cost simulations. For example, some of the benefits described below will be realized when the North and South balancing areas are combined—a factor not captured in the production cost model. A discussion regarding how the many benefits of the ON Line are and are not reflected in the production cost analysis is set forth below:

- **Dispatch Optionality:** The flexibility provided by combining the dispatch of the two systems will result in significant cost savings, not all of which are captured by the production cost simulation tool, PROMOD. For example, with the ON Line, system operators can take advantage of changes in market conditions within the two systems by increasing lower cost generation in one system and using the additional generation to serve load in the other system. This benefit is not fully reflected in the PROMOD model, which utilizes static market price curves and does not reflect potential changes in market prices. In reality, market prices are volatile and frequently change. The ON Line will allow the Companies to optimize the exchange of resources between North and South on a real time basis in response to changes in market conditions.

- **Load Diversity:** The estimated load diversity between Nevada Power's peak system load and the combined system load is 0.5 percent, or approximately 35 MW. This results in a 35 MW reduction in the required resources resulting in an estimated savings of approximately $57 million. The estimated ON Line benefits calculations presented in Docket No. 10-02009 utilized the cost of the new Harry Allen combined cycle plant of $1,628/kW. For ease of comparison, the benefits calculations presented here utilize the same assumption. This benefit is not directly captured in the PWRR analysis.

- **Reduction in Planning Reserve Margin Requirement:** A 35 MW reduction in load diversity benefits also results in a reduction in planning reserve requirements. The reduction in planning reserve requirements is approximately 15 percent of 34 MW, or 5 MW. This reduction in planning reserve requirements results in additional estimated savings of approximately $8 million. This benefit is not directly captured in the PWRR analysis.

- **Reduction in Contingency Reserve Obligation:** As a stand-alone system, Nevada Power's contingency operating reserve is equal to its largest generation contingency minus the limited amount of assistance available from the Southwest Reserve Sharing Group ("SRSG"). For the Sierra system, the Northwest Power Pool ("NWPP") assistance is not a limiting factor, so as a stand-alone system the reserve requirement for Sierra tends to be at its minimum, equal to the Company's NWPP pool reserve obligation amount.

As a combined system, the Companies likely would use the NWPP reserve sharing group for generation contingency support, and discontinue Nevada Power's membership in the SRSG pool. Owing to the higher degree of accessibility to pool reserve assistance from the NWPP, by virtue of the ON Line and the Harry Allen transmission connection to Utah, the combined system, including the Nevada Power service area, the contingency reserve to be held by the combined Companies will be reduced.

The Companies understand that changes to the WECC regional standard, under which its contingency reserve obligation is calculated, may take effect in early 2014. These changes will affect the quantity of contingency reserves that each Company must carry; however, because of the higher degree of accessibility to the NWPP reserve sharing group as a combined Balancing Area, the contingency reserve obligation with ON Line in place will tend to be lower than the sum of the reserve obligations of the two Companies taken separately under the new regional standard. The effect of the new WECC regional standard for contingency reserve obligation was duly considered in the production modeling simulations, with the change assumed to be in place on January 1, 2014.

As a combined system, not only would the contingency reserve obligation be reduced, but units from both Sierra and Nevada Power could supply the reserves. The Company estimates the 30-year PWRR savings from shared reserves to be approximately $40 million.

- **Optimization of Gas Transportation Assets**: The ON Line is expected to improve the utilization of gas transportation facilities in two ways. First, the Companies will be able to take greater advantage of their firm gas transportation capacity. For example, due to the large variation in load between the peak summer season and the off-peak winter season, Nevada Power's firm transportation agreement with Kern River results in excess pipeline capacity during some off-peak periods. During these periods, unused pipeline capacity can be utilized to "deliver" lower-cost Rockies gas to Sierra via wire—by generating lower cost power in Southern Nevada for delivery to Northern Nevada over the ON Line. These benefits are captured in the joint dispatch benefits modeled in PROMOD.

  The second improvement in gas transportation use results from the potential availability of additional gas pipeline transportation capacity for the Sierra natural gas Local Distribution Company ("LDC") during peak load winter conditions. Additional availability of limited natural gas pipeline transportation capacity for use by the LDC could allow the Companies to defer very expensive expansions of pipeline systems that currently serve Northern Nevada. The benefit of deferring an investment in pipeline expansion capacity is not captured in the PROMOD simulations. In Docket No. 10-02009, the estimated value of this ON Line benefit was approximately $64 million. This figure has not been updated.

- **Optimization of Regional Market Purchases.** The ON Line will enable the Companies to better exploit regional diversity in the power markets. Northern customers, who are primarily interconnected to the Pacific Northwest, will have greater ability to access Southwestern markets during adverse hydro conditions. Southern customers, who are primarily interconnected to California and the Desert Southwest, will be better able to take advantage of Pacific Northwest energy during favorable hydro conditions or extreme heat in the southwest. These gains from the ON Line result not only from actual day-to-day and hour-to-hour market transactions, but also from forward purchases used to hedge load. The Companies may well be able to hedge in either the Pacific Northwest or Desert Southwest markets and take advantage of price differentials that will change from time to time. The value of ON Line in hedging power prices between regions is not reflected in production cost simulations.

- **System Reliability Benefits.** The availability of a direct transmission interconnection between Nevada Power and Sierra will allow each system to support the other system during outages and other events, thereby improving the reliability of both systems. The reliability benefits of ON Line are not reflected in production cost simulations.

  Ability to Deliver the Most Economical Mix of Renewable Energy Resources. Renewable resources in Nevada are unevenly distributed throughout the State as shown in Figure TP-09. In general, geothermal and wind resources are located predominantly in the North, while solar resources, both thermal and PV, are concentrated in the South. Geothermal and wind have historically been lower cost resources than solar. In order to meet the RPS, Nevada Power has contracted with numerous renewable projects located in Northern Nevada, and Sierra has contracted with a large-scale solar project in the South. The Companies have been able to manage the uneven physical distribution of resources through contractual mechanisms. Over the long term, however, this is not the most cost effective way of complying with the RPS. Sierra's electric system is simply too small to accommodate the "must take" energy from the wealth of renewable resources available in the North. Without the ON Line it will be necessary to uneconomically dispatch (back down or shut off) existing generating resources on Sierra's system (including the most economical base loaded units), likely for significant portions of the year when loads are down, in order to accommodate renewable “must take” resources. In 2015, without the ON Line, energy delivered into Sierra’s system from projects under contract to Nevada Power will be significant, accounting for approximately 23% of the system requirement.

- Also, the ability to dispatch generating units to compensate for fluctuations in the intermittent output of resources such as wind or PV would be severely compromised. Recognizing that the costs of each renewable technology can vary greatly over time, the ON Line will make it feasible for the Companies to choose the most economical mix of resources without being constrained by geography or physical limitations. These ON Line benefits are reflected in production cost simulations.

- **Ability to Accommodate Intermittent Generation is Improved**. Utilities throughout the nation are struggling to estimate the effects of the interconnection of large scale intermittent resources and how to manage operations under such circumstances. With fewer units on Automated Generator Control, less "headroom" in those that are available, and limited quick start capability, the ability of the Northern system to follow changes in intermittent resource output, as well as its ability to recover from disturbances within NERC's specified time frames could be severely compromised. By allowing joint dispatch of the two systems, the ON Line will expand the portfolio of units available to follow such fluctuations, and reduce, though not entirely eliminate, the operational concerns associated with intermittent resources. The benefits of ON Line in accommodating intermittent generation are not reflected in production cost simulations.

- **Protection Against Conventional Fuel Source Uncertainty.** The PWRR analysis shows increased benefits of almost $7.5 million under the high natural gas price scenario. ($43.1 million versus $35.5 million), reflecting the ON Line's positive contribution to reducing exposure to natural gas prices. The ON Line will perform a similar function in the event of the retirement of any or all of the Reid Gardner coal units, allowing Northern Nevada geothermal and coal resources to substitute for Reid Gardner generation. This ON Line benefit is not reflected in the PWRR analysis.

- **Protection Against Carbon and Greenhouse Gas Uncertainty.** A white paper on transmission and renewable energy prepared by representatives of the renewable power industry notes an additional set of benefits that can be expected from the ON Line, and which are not captured by PROMOD:

> Going forward, a robust transmission grid can provide valuable protection against a variety of uncertainties in the electricity market. Fluctuations in the price of fossil fuels are likely to continue, particularly if the electric sector becomes more reliant on natural gas. Further price risk associated with the potential enactment of policies that would establish a price for CO_2 emissions, in addition to uncertainty concerning the viability of technologies such as nuclear power and coal carbon capture and sequestration, place a greater premium on the flexibility and choice provided by a robust transmission grid. For regions where the quality of renewable energy resources is comparatively low, transmission is also important for ensuring that those regions have access to low-cost, zero-emission energy sources. Given that transmission infrastructure typically remains in service for 50 years or more, it is impossible to predict how fuel prices, policies and technologies will evolve over that time. As a

> result, all consumers should view transmission as a valuable hedge against uncertainty and future price fluctuations.[23]

In this regard, the Companies also performed an analysis to determine the potential benefits of additional renewable resources above the levels modeled in the base case under various GHG regulatory scenarios. As described in the Economic Analysis section below, Case 4 includes approximately 244 MW of additional renewable energy over the Preferred Case. Without the ON Line project additional geothermal and wind resources located in Northern Nevada cannot be delivered to Southern Nevada, and Southern Nevada solar resources cannot be delivered to Northern Nevada. The addition of ON Line has the potential to provide significant additional savings with increased levels of renewable resources and risk mitigation under many scenarios.

(B). 500 kV Sunrise Tap Off-site Improvements and 500 kV Line Fold Easements

In the 2009 IRP, Nevada Power requested and received Commission approval to proceed with the Sunrise 500 kV Tap Off-site Improvement Project, but with a 2018 in-service date. As described above, recent studies show that the Harry Allen 500/230 kV addition is a preferred alternative for moving bulk energy from the 500 kV system into the Las Vegas Valley (see Section 9 above). Nevada Power has determined that the Sunrise 500/230 kV project (and associated 230 kV and 138 kV infrastructures) will not be required until well beyond 2020. The Company has not expended any of the $14.3 million approved by the Commission for the off-site improvements. Because the existing permit issued by Clark County requires completion of these improvements by December 3, 2012, the Company is requesting an extension from Clark County to keep the project viable. However, the Company will not incur major expenditures during the Action Plan period. The Company is seeking Commission approval to suspend the project indefinitely.

(C). Northwest Substation 2ND 500/230 kV Transformer

In the 2009 IRP, Nevada Power requested and received Commission approval to proceed with the Northwest Substation 2nd 500/230 kV transformer project, with a 2014 in-service date. As described above, recent studies show that the Harry Allen 500/230 kV addition is a preferred alternative for moving bulk energy from the 500 kV system into the Las Vegas Valley (see Section 9 above). Nevada Power has determined that the Northwest Substation 2nd 500/230 kV Transformer may not be required until beyond 2020. The Company is not proposing to expend funds on this project during the Action Plan period. The Company is seeking Commission approval to suspend the project indefinitely.

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[23] American Wind Energy Association and Solar Energy Industries Association, "Green Power Superhighways: Building a Path to America's Clean Energy Future" at 13 (February 2009) (available at http://seia.org/cs/newsdetail?pressrelease.id=346).

(D). NORTH LAS VEGAS VALLEY AREA ROUTING AND SITING

In the 2009 IRP, Nevada Power requested and received Commission approval to indefinitely defer the development of four North Las Vegas Valley Area Routing and Siting ("VARS") 230/12 kV substations and to proceed with, but delay to 2017, the VARS Thunderbird 230 kV Substation. Current load growth projections indicate that the Thunderbird 230 kV substation can be further delayed to at least 2019. The Company will continue to evaluate the need and timing for Thunderbird project and will seek re-authorization from the Commission to proceed if and when it is needed. The Company will continue working with Nellis Air Force Base regarding the proposed location for the substation but will not incur major expenditures on the project during the Action Plan period.

(E). VALLEY ELECTRIC ASSOCIATION ("VEA") 2ND SOURCE

In the 2009 IRP, the Company requested continued Commission approval of a 230 kV Facility Interconnection Agreement ("FIA") with VEA that was approved in the 2006 IRP. That agreement required the Company to construct and own approximately 6 miles of new 230 kV line. However, several issues arose with permitting the line and with the necessity of the line to serve native load (the load that was to be served from the line is no longer forecast to occur). Rather than affirming or rescinding approval of the line, the Commission chose to require quarterly reports on the status of the interconnection with VEA (Docket 10-07003, Order at paragraph 403).

On November 17, 2010, the Company informed the Commission that it had executed an Amended and Restated Transmission Interconnection Agreement ("TIA") with VEA that supersedes the terms and conditions of the FIA, resolves all disputes between the parties, and relieves the Company of its obligation to build the 230 kV line.

The TIA was filed with the FERC on October 25, 2010 as Docket ER11-1912-000. Under the terms of the Amended and Restated TIA, VEA will build a new 230 kV transmission line from VEA's Desert View Switching Station to a new pole located immediately outside of Nevada Power's Northwest Substation and VEA will pay for all actual costs associated with interconnecting its facilities to the Northwest Substation. In addition, VEA has notified Nevada Power that it intends to move its transmission system from the Nevada Power Balancing Area to the CAISO Balancing Area effective January 1, 2013. This move is discussed in Section 14(E) below.

11. PREVIOUSLY APPROVED TRANSMISSION PROJECTS COMPLETED

Transmission work related to the following Commission-approved projects was completed during the 2009-2012 Action Plan Period:

(A). Harry Allen Combined Cycle 500 kV Interconnection

The Harry Allen Combined Cycle 500 kV Interconnection was placed in service on July 16, 2010. The final cost was $3.6 million, which is less than the $4.5 million authorized by the Commission.

(B). Harry Allen 345/230 kV PacifiCorp Transformer

The Harry Allen 345/230 kV PacifiCorp Transformer was placed in service on June 17, 2011. Disputes with PacifiCorp over responsibility for the cost of the project were resolved between the parties, and a settlement agreement was filed with the FERC and is pending approval. Under the settlement agreement, all project costs are to be funded by PacifiCorp and all incremental capacity resulting from the installation of the transformer is to be assigned to PacifiCorp.

(C). Mohave 500 kV Modifications (Laughlin 2nd Source)

The Mohave 500 kV Modification (Laughlin 2nd source) was placed in service on June 10, 2011. Nevada Power's share of the final project cost was $457,790 (including AFUDC), which is just under the $462,000 (excluding AFUDC) authorized by the Commission.

(D). EEI STEP Transformer Sharing Program

The Commission approved $4.5 million in funding for the Edison Electric Institute ("EEI") STEP Transformer Sharing Program in the Fourth Amendment to Nevada Power's 2006 IRP. The original budget request was based on Nevada Power's best estimate of the cost of purchasing incremental spare autotransformers in the event that the Company could not meet its autotransformer MVA obligation as defined by the EEI STEP Sharing Agreement. Presently, Nevada Power has committed on-hand spare autotransformers to the program, satisfying the MVA commitment in all voltage classes without expending any incremental dollars.

12. SUMMARY CASH FLOWS FOR ALL TRANSMISSION PROJECTS

The following figures summarize cash flows for all project requests for 2013-2015 Action Plan Period funding.

FIGURE TP-17 - TRANSMISSION PROJECTS ESTIMATED CASH FLOWS
(millions, excluding AFUDC)

Project:	Pre 2013	2013	2014	2015	3-Year Total	Project Total
WestConnect, Nevada Power Share		$0.146	$0.150	$0.154	$0.450	
ON Line (Total Cost)	$380.8	$169.1	$0.7	$0.5	$170.3	$552.1

13. TRANSMISSION LOSSES

NAC §704.9385(3)(h) requires that Nevada Power include in its transmission plan a description of its efforts to reduce the impact of line losses on future resource requirements. Nevada Power's efforts to evaluate and mitigate line losses are ongoing. Line losses are calculated into the overall plan of service for load growth, selection of Company-owned generation, IPP development, and renewable energy evaluations in order to develop the most cost effective facilities (i.e., the impact of losses is evaluated in those cases where Nevada Power has the ability to select from various options).

In specific cases, existing facilities are analyzed for possible upgrade. An example of this analysis was included in the Nevada Power Second Amendment filing to its 2009 IRP, where the capital cost of the Harry Allen 500/230 kV transformer was compared to the additional costs associated with the redispatch of generation and additional losses associated with the Crystal PST operation. This analysis, the details of which are described in Section 9 above, showed that increased losses had a lesser cost than the addition of a new 500/230 kV transformer bank.

In cases of 500 kV construction or high reactive loading, planning engineers have been assigned to conduct individual line loss studies. For example, extensive loss studies around various possible ON Line voltages and configurations were prepared and filed with the 2009 IRP.

14. REGIONAL AND FEDERAL REGULATORY ISSUES

(A). SUMMARY OF FERC ORDERS

NAC §704.9385(3)(g) requires that Nevada Power include in its Transmission Plan a summary of the impacts of relevant orders issued by the FERC since Nevada Power's last IRP. The following information is being provided in compliance with this requirement.

FERC Order 1000

FERC issued Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Utilities*, on July 21, 2011 ("Order 1000"). Order 1000 expands on the principles set forth in FERC's Order No. 890, *et al*., *Preventing Undue Discrimination and Preference in Transmission Service* ("Order 890") and requires transmission owning and operating utilities to amend their Open Access Transmission Tariffs ("OATT") and/or other jurisdictional agreements to:

(a) Include in its OATT a regional transmission planning process that produces, in consultation with stakeholders, a regional transmission plan that includes the following transmission planning principles set forth in Order 890: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning. Public utility transmission providers must also include as part of their regional transmission planning process an evaluation process (with stakeholders' input) for alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process such as transmission facilities needed to meet reliability requirements, address economic considerations, and/or meet transmission needs driven by public policy considerations;

(b) Include in its OATT as part of its regional transmission planning process a cost allocation methodology for the cost of new transmission facilities selected in a regional transmission plan satisfying six cost allocation principles. The cost allocation principles in general are that: (1) costs be allocated in a manner that is roughly commensurate with benefits; (2) there be no involuntary allocation of costs to non-beneficiaries; (3) if using a benefit to cost threshold ratio to determine which transmission facilities have sufficient net benefits as a methodology for selection of in a regional transmission plan for cost allocation purposes, that benefit/cost threshold cannot exceed 1.25 unless justified with FERC; (4) costs are only allocated to the region benefiting from the project, unless those outside the regional voluntarily agree to be allocated costs; (5) the methodology be transparent for determine benefits and identifying beneficiaries; and (6) different methods can be utilized for different types of facilities (e.g., reliability facilities, economic facilities, *etc*.);

(c) Include in its OATT an interregional transmission planning process and interregional cost allocation methodology. Order 1000 requires neighboring regions to have a common interregional cost-allocation process for new interregional facilities selected in a plan for the purposes of cost allocation; and

(d) Eliminate from its OATT or any FERC jurisdictional agreement any federal right of first refusal that favors the incumbent transmission company with respect to the construction of transmission facilities selected in a regional transmission planning process for cost allocation purposes

Order 1000 requires the Company to make compliance filings in October 2012 (regional), and April 2013 (interregional). The Company is currently undertaking efforts with other WestConnect participants and interested stakeholders to develop a regional transmission planning process and cost allocation methodology to satisfy the Company's Order 1000 compliance obligations. In accordance with Order 1000, the Company must submit a compliance filing with FERC by October 11, 2012 that provides a regional transmission planning process and cost allocation methodology.

On May 17, 2012, FERC issued Order No. 1000-A ("Order 1000-A"). In Order 1000-A, FERC denied rehearing of Order 1000 but clarified the following:

1. Each planning region must have a clear enrollment process that defines how entities, including non-public utility transmission providers, make the choice to become part of the region.

2. Claims that a federal right of first refusal in a FERC-approved agreement is protected by a *Mobile-Sierra* provision are properly made as part of an Order No. 1000 compliance filing. Before addressing proposed tariff revisions to comply with the rule, FERC will decide whether the agreement is protected by a *Mobile-Sierra* provision, and if so, whether the applicable standard of review to require removal of the right of first refusal has been met.

3. The transmission planning process is not intended to assess the merits of federal or state public policy requirements, but to help utilities comply with those requirements by considering new transmission facilities driven by such requirements.

4. Transmission providers are still required to make the necessary compliance filings by October 2012 and April 2013.

Petitions for review of Order 1000 and 1000-A have been filed with the United States Court of Appeals for the District of Columbia Circuit and are pending in Docket Nos. 12-1232.

The PUCN is conducting an investigation on the Company's Implementation of Order 1000 in Docket 12-01003. In that docket, the Company has provided the Commission information about the scope of its work in WestConnect on Order 1000 implementation.

The Company does not believe that in order to fulfill its compliance obligations under Order 1000, that such compliance obligations would require the Company to implement tariff provisions that would interfere with the Commission's resource planning authority. Rather, the Company believes that there are means under Order 1000 for the Company to seek to protect or defer to the Commission's resource planning authority.[24] FERC stated in Order 1000-A that "Order No. 1000's transmission planning reforms are concerned with process; these reforms are not intended to dictate substantive outcomes, such as

[24] With respect to the ON Line, which is the only major transmission project the Company is currently constructing, it should be excluded from Order 1000 compliance. First, the ON Line is a local transmission project being constructed solely within Nevada. Second, the ON Line was approved by the Commission and FERC before the effective date of Order 1000.

what transmission facilities will be built and where."[25] (Furthermore, in Order 1000-A, FERC clarified that transmission facilities in a public utility transmission provider's local transmission plan will not be subject to regional or interregional level approval, unless the utility seeks to have any of the facilities selected in the regional transmission plan for purposes of cost allocation.

(B). REGIONAL PLANNING UPDATE

NAC §704.9385(3)(f) requires that Nevada Power include in its transmission plan a description of the participation of the utility in regional planning organizations and an explanation of the role of those organizations in the transmission planning process of the utility. The following information is being provided in compliance with this requirement.

Transmission Expansion Planning Policy Committee ("TEPPC")
TEPPC is a WECC Committee answering to WECC's Board of Directors; it performs the following three main functions: (1) oversees database management, (2) provides policy over and management of the planning process, and (3) guides the analyses and modeling for Western Interconnection economic transmission expansion planning. These functions complement but do not replace the responsibilities of WECC members and stakeholders to develop and implement specific expansion projects. Nevada Power is a voting member of TEPPC, participating in its regional planning process guidance and development of the policies, including coordination with WestConnect, the Southwest Area Transmission Group ("SWAT") and the Sierra Subregional Planning Group ("SSPG"). Participation in TEPPC provides valuable input and enables Nevada Power to coordinate all of its transmission planning activities in other regional planning groups in Western Interconnection. The impact of FERC Order 1000 on the TEPPC is unclear at this time.

WestConnect Transmission Planning Regional Group ("WestConnect")

Transmission providers established WestConnect for planning coordination in the Desert Southwest area (see Figure TP-12) by signing the WestConnect Project Agreement for Subregional Transmission Planning (the "STP Agreement"). The STP Agreement established a Planning Management Committee ("PMC") made up of one representative of each of the signatory parties. Currently, 17 transmission owners are members of the PMC. The PMC is tasked with implementation of a subregional planning process that complies with the WestConnect Planning Objectives and Procedures for Regional Planning. This guiding document was approved by the WestConnect Steering Committee in an August 24, 2006 Memorandum of Understanding in order to comply with the FERC Open Access Transmission Tariff--Attachment K--Transmission Planning Process requirements and guidelines (the Order 890, *et al.* requirements).

WestConnect planning activities are fully open for public participation. Subregional transmission planning in WestConnect is being performed by SWAT, the Colorado

[25] Order 1000-A at paragraph 188.

Coordinated Planning Group and the SSPG (in which Sierra is a member) that form and make up the WestConnect planning area. Annually, a ten-year integrated regional transmission plan is derived from their efforts that coordinate all transmission plans across the WestConnect planning area. Nevada Power participates in the WestConnect activities directly and through SWAT. WestConnect was identified as a planning region under FERC Order 1000. It is expected that the August 24, 2006 Memorandum of Understanding will be replaced by a new governance document; however, that new governance document has not been developed yet.

Southwest Area Transmission Group (SWAT)

Nevada Power is a member of SWAT, one of the three Subregional Planning Groups ("SPGs") working together to support WestConnect. The SWAT's planning area of interest is the Arizona, New Mexico, Southern Nevada and Texas (El Paso) areas (see Figure TP-15). SWAT is comprised of transmission regulators/governmental entities, transmission users, transmission owners, transmission operators and environmental entities. The goal of SWAT is to promote regional planning in the Desert Southwest. The SWAT regional planning group includes transmission planning subcommittees, which are overseen by the SWAT Oversight Committee. Nevada Power holds a seat on the SWAT Oversight Committee.

SWAT includes the following permanent planning subcommittees: Central Arizona Transmission Studies, Colorado River Transmission, Southeastern Arizona Transmission Studies, and New Mexico. The following four working groups currently active within SWAT:

- Advisory
- Eldorado Valley Studies
- Short Circuit Studies
- Transmission Corridor

Nevada Power participates in the SWAT activities directly and through its working groups. The impact of FERC Order 1000 on the SWAT is unclear at this time.

Eldorado Valley Studies Working Group

The Eldorado Valley Studies Working Group ("EVSG") was established in 2010 to address potential interconnection projects in the Eldorado Valley, south of Las Vegas. EVSG provides a forum in which the owners of the electric system in the Eldorado Valley and its environs, as well as those interested in interconnecting projects into that system, can coordinate study work to determine the technical requirements of those interconnections. Both transmission developers and utilities have expressed an interest in interconnecting at this location, proposing either Alternating Current ("AC") or High Voltage DC ("HVDC") transmission amounting to up to 20GW of the additional injection at Eldorado Valley. Consequently, the Eldorado Valley is a potential point of transmission congestion. Also, the fault duty levels at its four exiting major substations (Mead, Marketplace, McCullough, and Eldorado) have reached equipment limits and will require mitigation for future interconnections. EVSG has already developed a draft master plan that proposes construction of the new Agora Substation, accommodating both AC and HVDC projects. The next EVSG goal is a Fault Duty Study that would propose a general development accommodating certain levels of injection.

Nevada Power participates in the EVSG activities directly and through SWAT.

FIGURE TP-18 - SWAT MAP

(C). ENERGY IMBALANCE MARKET ("EIM")

The Western Interconnection is considering adaptation of some form of an energy imbalance market ("EIM") through which lowest cost generation resources would be dispatched to address energy imbalances. Three major efforts are underway within the Western Interconnection to study the concept of an EIM:

<u>WECC</u>
The WECC effort began with cost and benefit studies, and recently resulted in the issuance of an RFP for a facilitator for market design. WECC closed the RFP without acting on it due to concerns of WECC members, however. WECC is currently participating in industry discussions to determine if there is a role for WECC in establishing an EIM, and it is reviewing data sharing issues related to an EIM.

<u>Public Utility Commission (PUC) EIM Group</u>
The State-Provincial Steering Group is a group of State commissions that are collaborating to develop a more detailed cost-benefit analysis of an EIM. In order to perform this analysis, the PUC EIM Group is attempting to develop a detailed market design and cost estimates premised on either the Southwest Power Pool or the California Independent System Operator ("CAISO") as the market operator.

Collective of Northwest Entities

A consortium of Northwest BA's largely representing the Northwest Power Pool ("NWPP") footprint is discussing an analysis of all potential solutions between today's bilateral market and a full EIM, including the Joint Initiatives projects[26]. There is some discussion among stakeholders about potentially bringing this effort into the NWPP.

The Companies are involved in both the WECC discussions around EIM and the Collective of Northwest Entities discussions and process to further develop the conceptual framework for an EIM. At this time the Companies require answers to fundamental questions regarding these initiatives before any decisions can be made on an EIM or other measures including: (1) how an EIM would be structured; (2) how an EIM would operate; (3) who would run the EIM; (4) what would it cost to establish such a market; (5) what, if any, anticipated benefits the EIM may provide; (6) what obligations and costs may be imposed on participants in the EIM; and (7) what costs such a market may impose on Nevada ratepayers.

The Companies participated in the Commission's investigation into EIMs in Docket 11-04025.

(D). MERCHANT SUBSTATION BALANCING AUTHORITY AREA (BAA) CHANGE

The owners of generation projects connected at the Merchant Substation in Southern Nevada have requested to be moved from the Nevada Power BAA to the CAISO BAA effective no later than January 1, 2013, in order to ensure that the Desert Star Plant, a natural gas-fired combined cycle plant, will meet California resource adequacy requirements.

(E). VALLEY ELECTRIC ASSOCIATION (VEA) BALANCING AUTHORITY (BA) CHANGE

VEA has notified Nevada Power that it intends to move VEA's transmission system from the Nevada Power BA to the CAISO BA effective January 1, 2013. VEA and Nevada Power have entered into a Transition Agreement that establishes the process for VEA to join the CAISO BA as a Participating Transmission Owner, Utility Distribution Company, and Load Serving Entity. On October 14, 2011, the CAISO filed the Transition Agreement with FERC as Docket ER12-84-000. On December 14, 2011, FERC issued an order approving the Transmission Agreement. Upon the effective date of VEA's move into the CAISO, VEA's Service Agreement under the NV Energy Electric Service Coordination Tariff will be terminated. Unless there is a change that impacts the Company, there will be no further reports on the VEA status.

[26] The Joint Initiative projects were developed by a Joint Initiative Taskforce ("JIT"). The JIT is a collaborative effort of WestConnect, Northern Tier Transmission Group and Columbia Grid. The JIT projects will be evaluated by the consortium of Northwest BAs.

15. TRANSMISSION COMPLIANCE ITEMS

In its Order in Docket No. 10-06015 (¶ 97), the Commission directed Nevada Power to include in its 2012 IRP a description of the steps it has taken to improve its process for determining interconnection cost estimates associated with all PPAs submitted in an IRP.

The process for determining interconnection cost estimates associated with interconnection requests is specified by the FERC-approved OATT[27]. Attachment N to the OATT provides the Large Generator Interconnection Procedures ("LGIP") for generators greater than 20 MW, and Attachment O to the OATT provides the Small Generator Interconnection Procedures ("SGIP") for generators 20 MW and less. These procedures include three study phases for interconnection requests: (1) a Feasibility Study; (2) a System Impact Study; and (3) a Facilities Study (more fully described below).[28]

The cost estimates for PPAs that are submitted for approval in an IRP are derived from the most recent completed interconnection study for that project. The quality of the estimate is dictated by the study phase that the project is in. For instance, the cost estimate for a project in the Feasibility Study Phase or the System Impact Study Phase would be preliminary and non-binding as specified in the OATT. The Feasibility and System Impact Studies are not intended or designed to provide construction quality cost estimates.

The LGIP and SGIP require the transmission provider to conduct studies in evaluating a generator interconnection request. There are three phases of studies, each with different requirements for estimating costs associated with the requested interconnection, as well as different timelines and costs for each study required for each customer. A brief description of the LGIP studies follows (SGIP charges and timeframes may differ depending on the scope of the proposed project):

1. Feasibility Study. Preliminary evaluation of the feasibility of the proposed interconnection. The Feasibility Study consists of a power flow and short circuit

[27] The Open Access Transmission Tariff, NV Energy, Inc. Operating Companies FERC Electric Tariff, Third Revised Volume No 1 can be accessed at http://www.oatioasis.com/NEVP/index.html.

[28] The Company is in the process of proposing changes to Attachment N and O of its OATT. These proposed revisions will be filed with the FERC for review and approval, with opportunities for interested participants to comment on the Company's filing. Although the Company is seeking modifications to the FERC's *pro forma* tariff requirements with respect to the generator interconnection process, the principles governing requests by interconnecting generators are not being modified. For example, the Company is proposing changes to improve the interconnection process for customers by: (1) establishing a coordination/pre-application process that will identify issues with an interconnection prior to the Transmission Customer entering the formal Interconnection Queue and that will address unique land issues in Nevada; (2) increasing the timeframe for the completion of the System Impact Study to ensure that the study can more comprehensively address citing and other issues unique to Nevada while eliminating the need for a Feasibility Study; (3) giving customers the option of requesting a Feasibility Study in the event they would like such a study following the pre-application process.

analysis and provides a list of facilities and a non-binding good faith estimate of cost responsibility and a non-binding good faith estimate of the time required to construct the facilities. The transmission provider is required to use reasonable efforts to complete the study within 45 calendar days, and the Interconnection Customer must deposit $10,000 to initiate the study. See Section 6 of the LGIP and Section 3.3 of the SGIP.

2. System Impact Study. Evaluation of the impact of the proposed interconnection on the reliability of the transmission system. The System Impact Study consists of a short circuit analysis, a stability analysis, and a power flow analysis and provides a list of facilities and a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct. The transmission provider is required to use reasonable efforts to complete the study within 90 calendar days, and the Interconnection Customer must deposit $50,000 to initiate the study. See Section 7 of the LGIP and Section 3.4 of the SGIP.

3. Facilities Study. Specifies and estimates the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the System Impact Study. The Facilities Study identifies the electrical switching configuration of the interconnection equipment; specifies the nature and estimated cost of any Transmission Provider Interconnection Facilities and Network Upgrade facilities necessary to accomplish the interconnection; and estimates the time required to complete the construction and installation of such facilities. The transmission provider is required use reasonable efforts to complete the study within 90 or 180 calendar days (as determined by the Interconnection Customer), and the Interconnection Customer must deposit $100,000 to initiate the study. See Section 8 of the LGIP and Section 3.5 of the SGIP.

The OATT provides up to 225 days for the transmission provider to perform the study work if all three studies are performed. The interconnection customer is also permitted time to review studies and determine whether to proceed to the next study phase. In general, many interconnection customers typically take 30-60 days after each study to review it and make a decision to proceed. Therefore, the timeframe for projects to progress through all three study stages of study can be close to one year. Upon conclusion of the Facilities Study, the Interconnection Agreement negotiations commence and the interconnection customer ultimately determines whether or not to move forward with an interconnection agreement with the Company.

Throughout the study process, many factors can and do change the cost estimates. Some of these factors may require re-studies, while others may be taken into account at later study stages or even during construction. Among them are: (1) changes to the interconnection customer equipment identified by the interconnection customer; (2) changes or withdrawal of a higher queued projects with identified upgrades; (3) delays or suspensions requested by interconnection customers; and (4) changes in economic factors driving the cost of equipment, *etc*.

Conclusion

Cost estimates for PPAs that are submitted for approval in an IRP are derived from the most recent completed interconnection study for that project, and the quality of the estimate is dictated by the phase of study that the project is in. If the project is in the Feasibility or System Impact Study Phase, cost estimates are non-binding and are not expected to be of construction quality. If this Commission requires construction quality estimates for interconnection facilities prior to approving PPAs for additional renewable resources, it will be necessary to complete the Facilities Study prior to submitting PPAs for Commission approval. For the reasons described below, the consequences of waiting for completion of a Facilities Study before seeking Commission approval of a renewable PPA could be severe, however.

As the Company described in Docket No. 10-02009 and Docket No. 11-03014, RFPs for renewable energy resources can sometimes yield upwards of ten times the number of projects that the Company could reasonably expect to contract for. Currently, respondents are expected to provide initial cost estimates from preliminary transmission studies, such as the Feasibility Study with their responses.

If the Company were to require the submittal of binding cost estimates, such as those generated in a Facilities Study, two possible scenarios could result. First, all of the bidders into the RFP could require the Company's Transmission Group to provide Facilities Studies, taxing already limited resources with projects that may not have a realistic chance of success due to factors completely unrelated to transmission interconnection costs. Since the Transmission Group must analyze projects sequentially pursuant to the OATT, they cannot prioritize among projects that may be more viable than others. Ultimately, this could cause weaker projects to clog the queue, eliminating better projects from proceeding through the study process in time to participate in the RFP. Second, the additional interconnection study costs incurred in order to prepare binding cost estimates before submitting a response to an RFP (and before a project is IRP approved) may drive developers to not pursue projects in Nevada. The Company is not aware of other neighboring utilities that require all bidders to have completed the interconnection process and all interconnection studies before submitting a proposal into a renewable RFP, so this additional cost would necessarily be internalized as part of the project risk costs for developers in Nevada.[29]

While the Company understands the concerns raised by the Commission, it views the current structure, pursuant to which preliminary interconnection cost information from the Feasibility Study is provided at the time of an RFP, as striking a reasonable balance between the desire for precision and the practical realities of the renewable development process.

[29] Notably, California and Oregon's RFP materials seem to explicitly contemplate that interconnection costs would be finalized after the RFP is completed.

16. MUST RUN UNIT RESTRICTIONS AND RESERVE REQUIREMENTS FOR TRANSMISSION RELIABILITY

Technical Appendix TRAN-6 describes the planning assumptions utilized for this IRP with regards to generation must run and reserve requirements. TRAN-6 summarizes the must-run unit constraints for the northern (Sierra) Balancing Area, identifying the need for dynamic voltage support in the northeastern area of the transmission system; the need for dispatch of Fort Churchill generation to support the Carson Area system during times when load is projected to exceed 300MW; and the need for reactive absorption during periods of light load demand in the Reno area.

TRAN-6 also describes the determination of operating reserves to be carried for the combination of the two Balancing Areas. These principles are also applicable to each stand-alone Balancing Area as well. Detailed in this section are the specific components and calculations for the components of operating reserve, including contingency reserve, regulating reserve, and spinning reserve. Contingency Reserve is shown to be a function of Load Responsibility in the near term; however, calculations are provided that incorporate an expected change in the regional standard regarding contingency reserves under which the obligation will be based upon a percentage of Balancing Area generation and load. Regulating reserves are shown to be a fixed base value plus fractions of the nameplate values of interconnected variable generation.

SECTION 3. ECONOMIC ANALYSIS

A. SUMMARY

In selecting the Preferred and Alternative Plans, the Company evaluated the various factors set forth in the Commission's regulations, including:

- The present worth of revenue requirement ("PWRR") for each alternative (see NAC 704.937(3));
- The present worth of societal cost ("PWSC") for each alternative (see NAC 704.937(4));
- Whether the plan mitigates risk (see NAC 704.937(5));
- Whether the plan provides adequate reliability (see NAC 704.937(6)(a));
- Regulatory and financial constraints (see NAC 704.937(6)(b));
- Whether the plan meets Nevada's Renewable Portfolio Standard (see NAC 704.937(6)(c)); and,

- Whether the plan meets the requirements for environmental protection (see NAC 704.937(6)(d)).

In accordance with NAC 704.948(2), the Company also considered other energy supply planning criteria in selecting the Preferred and Alternative Plans, including the relationship between mitigating risk, minimizing cost and volatility, and maximizing reliability. The Company selected as its Preferred and Alternative Plans combinations of resources that provide the best combination of attributes, without assigning specific weights to any particular factor.

Utilizing the results of the long-term load forecast, the demand-side management plan ("DSM Plan") and the renewable energy plan, Nevada Power identified the Company's resource requirements over a full thirty-year planning period (results are tabulated on twenty- and thirty-year bases). This analysis indicates that Nevada Power does not need to add incremental supply side resources until 2018. Nevada Power developed four alternative expansion plans for meeting its projected needs for incremental capacity and energy. The first expansion plan (Case 1) relies exclusively on market purchases to meet the first new incremental capacity and energy requirements in 2018. The second expansion plan (Case 2 – The Preferred Plan) centers on conventional gas-fired technologies-- a block of simple-cycle combustion turbines (375 MW) in 2018, and additional units in 2021. A third expansion plan (Case 3 – the Alternate Plan) backfills open capacity with a 275 MW Tolling agreement in 2018 through 2027. And the last plan (Case 4) is based on Company-built renewable energy resources in 2018.

The Company utilized a combination of two economic models to evaluate alternative resource plans over the planning period. Variations in the costs of producing energy between expansion plans were modeled using "PROMOD,"[30] a production cost simulation software model. Differences in the capital costs of constructing the different expansion plans were modeled using a Company-designed Capital Expenditure Recovery model ("CER"). The PROMOD model performs chronological economic dispatch of the Company's electric production resources and market purchases to satisfy load requirements in a least cost solution over the planning period. New renewable energy resources analyzed in the expansion plans were modeled in PROMOD as PPAs, using forecasted contract costs and hourly energy profiles that vary by month and time of day. The CER model calculates annual capital expenses associated with future electric facilities to satisfy load requirements that are proposed to be constructed during the planning period.

Key inputs to the PROMOD energy model include the load forecast, price forecasts for coal and natural gas, a purchased power price forecast, and the operating characteristics of both existing resources and the resource options being analyzed. The outputs from the production simulation model express the total forecasted production costs of each alternative expansion plan.

[30]PROMOD is a proprietary software product that the Company licenses from Ventyx Energy, LLC.

Key inputs to the CER include the construction costs of new facilities, along with accounting and financial assumptions, in order to compute the annual capital revenue requirements of the alternative expansion plans over the lives of each proposed facility.

The sums of the annual energy and capital costs over the planning period, discounted by the Company's weighted cost of capital, provide the present worth of revenue requirements ("PWRR") for the various resource plans. A comparison of the PWRRs (in today's dollars) of each expansion plan indicates which expansion plan meets future needs at the lowest total cost—considering production and capital costs. Stated differently, the expansion plan with the lowest PWRR represents the "least cost" solution for meeting incremental loads.

The Company's first significant need for additional resources is projected to occur in 2018.[31] In total, four different expansion plans were evaluated. The four expansion plans are described in Section 2 below.

The Company also evaluated the alternative expansion plans with sensitivities around high and low load forecasts, high and low fuel and purchase power ("F&PP") price forecasts, and high and low carbon forecasts. In addition, an economic analysis of the four plans with and without external system power sales was performed. The Company does not propose to justify any plan on the basis of external sales. However, because of the relatively low load factor of the Nevada Power system, periods of surplus capacity can be expected. Nevada Power anticipates selling this surplus capacity when market conditions allow. This sensitivity analysis is described in Section B.5 below.

B. ANALYSIS METHODOLOGY

The Company's analysis of future resource requirements begins with a long-term forecast of annual peak loads, energy, and a forecast of supply-side and demand-side resources. As load levels grow over time, along with retirements of older existing generation and the expiration of current power purchase contracts, the Company must plan for additional resources and conservation measures in order to provide continuous electric service. The integrated resource planning process provides structure for this planning effort, as well as transparency and regulatory oversight.

The Company itemizes its projected loads and generation resources over the 30-year planning period in the Loads and Resources ("L&R") tables. The Company reviews the projected shortfalls in maintaining sufficient generation to meet peak load conditions, and develops alternative resource plans, including the potential to leave some open capacity positions that could be filled with market purchases or a proposed resource at a future time. The use of the L&R table--including recent changes to the table--is further described in the Loads and Resources section of this narrative.

Pursuant to NAC 704.952(5), prior to making an IRP filing, the Company meets with the Commission's Regulatory Operations Staff and Bureau of Consumer Protection to

[31] See Figure LR-1B, Nevada Power's Loads and Resources Table, row 127.

present its key modeling assumptions and to provide an overview of the anticipated filing. The IRP workshop meeting materials for this filing are provided as Technical Appendix item ECON-1.

Once expansion plans were developed, an economic analysis was performed using PROMOD and the CER model. PROMOD simulates the dispatch of the electric system and estimates energy production costs. The results of the production cost simulation are impacted by assumptions such as existing internal generation and retirements, forecasted hourly loads, future generation expansion plans, transmission limits, energy and capacity purchases and sales, as well as fuel and wholesale power prices. The actual real-time dispatch of the electric system over the thirty year planning period will of course differ from PROMOD's dispatch simulation. Pursuant to NAC 704.922(2)(g), documentation of PROMOD's specifications and processes is included as Technical Appendix Item ECON-2.

Updates to key inputs made in performing production cost analysis (using PROMOD) include the following:

- The Company's base load forecast has been updated from the previously approved forecast in Docket No. 11-08011, and is described in the Load Forecast and Market Fundamentals volume.

- The F&PP forecast for natural gas and oil prices, coal prices, and wholesale regional purchase and sale power prices have been updated from the previously approved forecasts in Docket No. 11-08011. In addition, pricing structure for energy purchases from the northern regional market has been modified to allow two pricing levels or 'tiers.' These updates are described in the Load Forecast and Market Fundamentals volume.

- The renewable energy plan has been updated from that presented in Docket No. 11-08011. The modeling in this plan assumes that current commercial projects would be renewed when the contract expires, if necessary, to maintain RPS compliance, but would be renegotiated to reflect market pricing for that technology at that time. This plan is described in the Renewable Energy Plan section of this volume.

- The Company has adopted a methodology to account for the additional operating reserves needed to accommodate the variable nature of solar photovoltaic ("PV") and wind resources. The methodology is described in the Transmission Planning section of this volume.

- The Company has performed a periodic update of the assumptions for fixed and variable operation and maintenance ("O&M") costs. The updated costs were utilized in the PWRR analyses requested in Docket 11-08-019 and can be found in Technical Appendix GEN-1.

- The carbon price forecast has been updated from the previously approved forecast in Docket No. 11-08011, and is used in modeling a potential greenhouse gas cap-and-trade program ("GHG"). The carbon price forecast is described in the Load Forecast and Market Fundamentals volume. All alternative plans were run with and without the effects of a GHG program included in the generating unit dispatch cost.

- The construction of the previously approved One Nevada Transmission Line ("ON Line") has been delayed. All expansion plans assume the ON Line will be in service as of January 1, 2014, after which the Nevada Power and Sierra systems will be jointly dispatched.

The capital revenue requirements of the various expansion plans are calculated in the Company's spreadsheet based CER model utilizing several inputs specific to alternative projects including project construction costs, construction start dates, in-service dates. Financial inputs include the Company's weighted cost of capital and AFUDC rate, applicable tax rates, book and tax lives and insurance rates.

The PWRR for each expansion plan is calculated by summing the annual electric production costs and the total capital revenue requirements for all system additions, and then discounting these annual costs into today's dollars using the Company's weighted cost of capital. As described immediately below, sensitivity analysis also was performed to determine the most flexible plan under various scenarios, with the goal of determining the least cost plan that also mitigates risk under a range of future conditions. Finally, the alternative plans were modeled under these various scenarios with and without external system sales.

NAC 704.9475 requires the utility to conduct an analysis of sensitivity for all major assumptions and estimates used in the resource plan. Sensitivity analyses were conducted by modeling all expansion plans under high and low F&PP prices; high and low load forecasts; and mid, high, and low carbon price impacts, including a scenario with no future GHG cap-and-trade program. Each of the alternative plans is run under a total of twelve sensitivities, which are listed in Figure EA-4 below. A range of sensitivities around market prices, loads, and carbon impacts are incorporated into the expansion plan cases using PROMOD. In order to test all possible combinations of sensitivities, each of the four expansion plans was subjected to a total of 24 runs.

NAC 704.9355(1)(c)(f) states that a resource plan should include an analysis that considers the availability of long-term transmission rights and wholesale power purchases for delivery to Nevada Power's balancing authority. All of the expansion plans included some level of market purchases as a resource option. Market purchases were modeled as delivered to Nevada Power's border.

The Company separately analyzed the potential for obtaining firm transmission rights to an additional market. The Company queried the Open Access Same-time Information System ("OASIS") for firm available transmission capacity ("ATC") from the Palo Verde

500kV trading hub to the Mead 230kV ("Mead") interconnection within the Nevada Power balancing authority. The transmission providers that own transmission capacity for the full path from Palo Verde to Mead show zero MW of ATC on the OASIS site. Firm rights for up to 402 MW of transmission capacity are available on an annual basis from multiple transmission providers, commonly referred to in the wholesale markets as "pancaked transmission." Contracting for pancaked transmission exposes the transmission customer to multiple tariff rates for firm point-to-point transmission service, scheduling fees, and transmission losses. Under existing tariff rates, contracting for 402 MW of firm point-to-point transmission under pancaked rates would cost $15.89 million per year, with additional charges for scheduling and transmission losses.

Since the additional cost does not necessarily provide additional opportunities for firm market purchases, the Company does not propose entering into any new contracts for long-term transmission rights on transmission facilities owned by others.

1. KEY MODELING ASSUMPTIONS

(A). Generation Options, Capital Costs, and Performance Modeling

For generation expansion options, the following operating and cost characteristics were modeled:

i. Gas Combined Cycle Unit 2x1: The estimated installed cost of a 2x1 CC unit is $663 million (overnight construction cost in 2012$, excluding AFUDC). This unit was modeled with a summer peak capacity of 576 MW, an average summer capacity of 612 MW, and an average winter capacity of 650 MW. The full load summer heat rate is estimated to be 6,975 Btu/kWh (without duct burners). The estimated fixed and variable O&M costs are $14.18 per kW-yr and $1.28 per MWh, respectively.

ii. Gas Combined Cycle Unit 1x1: The estimated installed cost of a 1x1 CC unit is $446 million (overnight construction cost in 2012$, excluding AFUDC). This unit was modeled with a summer peak capacity of 237 MW, an average summer capacity of 261 MW, and an average winter capacity of 273 MW. The full load summer heat rate is estimated to be 6,989 Btu/kWh (without duct burners). The estimated fixed and variable O&M costs are $28.36 per kW-yr and $1.53 per MWh, respectively. The fixed O&M rate for a 1x1 configuration is higher because its labor requirements are similar to a 2x1 configuration.

iii. Three LMS 100 Combustion Turbine Units: The estimated installed cost of three LMS 100 CT units is $312 million (overnight construction cost in 2012$, excluding AFUDC). The three units were modeled with a combined peak summer capacity of 181 MW, a combined average summer capacity of 236 MW, and a combined average winter capacity of 277 MW. The full load summer heat rate is estimated to be 9,202 Btu/kWh. The estimated fixed and variable O&M costs are $2.42 per kW-yr and $3.23 per MWh, respectively.

iv. Three GE 7EA Combustion Turbine Units: The estimated installed cost of three 7EA CT units is $240 million (overnight construction cost in 2012$, excluding AFUDC). The three units were modeled with a combined peak summer capacity of 225 MW, a combined average summer capacity of 228 MW, and a combined average winter capacity of 233 MW. The full load summer heat rate is estimated to be 11,962 Btu/kWh. The estimated fixed and variable O&M costs are $1.76 per kW-yr and $0.05 per MWh, respectively.

v. Solar Photovoltaic, Fixed Axis: The estimated installed cost of five 20 MW poly crystalline PV plants with fixed axis rotation is $492 million (overnight construction cost in 2012$, excluding AFUDC). The PV resource was modeled in Southern Nevada with a summer capacity value of 38 percent of nameplate capacity. The estimated O&M cost is $16.7 per kW-yr.

vi. Wind: The estimated installed cost of two 72 MW wind plants is $356 million (overnight construction cost in 2012$, excluding AFUDC). The Southern Nevada wind plant is contemplated to have a 27 percent capacity factor and was modeled with a summer capacity value of 10 percent of nameplate capacity. The estimated O&M cost is $28.07 per kW-yr.

(B). JOINT SYTEM MODELING

All of the cases model both the Nevada Power and Sierra systems, with the planned ON Line transmission interconnection beginning in January 2014. Once ON Line goes into service, the modeling included joint dispatch of the Nevada Power and Sierra resources for energy supply. Sharing of operating or planning reserves was not modeled because the systems are currently separate balancing areas. Transfers between the two systems were limited by the capacity of the new transmission interconnection. The PROMOD production cost results are reported on a combined system basis. Any joint dispatch saving were split evenly between Nevada Power and Sierra. All reported PWRR results include the total production cost for both systems. The production cost data provided in Technical Appendix Items ECON-17 and ECON-18 also list the production cost for the Nevada Power and Sierra systems separately.

(C). THIRTY-YEAR PLANNING PERIOD

The resource planning regulations specify the calculation of the 20-year PWRR for each alternative expansion plan. However, for mid-period resources or long lead-time and capital intensive projects, evaluating a project solely on the basis of a twenty-year PWRR can understate the value over its useful life, particularly for projects that enter into service later in the period.

For example, all of the cases analyzed in this resource plan filing show the first addition of resources in the 2018 time frame. The 20-year PWRR analysis in this filing covers the period of 2013 through 2032. The costs and benefits of any incremental resource only would be captured over the first 15 years of the resource life, yet new generation facilities have useful lives of 35 years or more. Therefore, a thirty-year PWRR for all expansion plans has been calculated and included to provide additional description of the useful benefits of the projects.

(D). RENEWABLE ENERGY MODELING

Renewable energy resources were modeled for both Nevada Power and Sierra in all cases in accordance with the requirements of the RPS. The renewable energy modeling was based on a mixture of solar, geothermal, wind, biomass and hydro generation.

A complete listing of the renewable energy resources added to each case is provided in Technical Appendix Item REN-1. Case 4 includes Company-built renewable energy resources in excess of the RPS requirements.

(E). OPERATING RESERVES MODELING

Operating Reserve, including Contingency Reserve, Regulating Reserve, and Spinning Reserve were included in the model. The calculation of operating reserves are described in the Transmission Planning Section of the narrative and include regulating reserves, which are a fixed base value plus fractions of the nameplate values of interconnected variable generation.

(F). LONG-TERM TOLLING AGREEMENT MODELING

A long-term, summer-only tolling agreement was modeled as a potential supply resource in some alternative plans. The price and performance for the resource was patterned after the responses to a Nevada Power request for proposals for long-term purchase agreements.

2. LIST OF EXPANSION PLANS

NAC 704.937(1) requires a utility's supply plan to contain a "diverse set of alternative plans which include a list of options for the supply of capacity and electric energy" and that "includes a description of all existing and planned facilities for generation and transmission, existing and planned power purchases, and other resources available as options to the utility for the future supply of electric energy." The description must include the expected capacity of the facilities and resources for each year of the supply plan. At least one alternative plan must be of low carbon intensity.

Nevada Power has largely closed any open positions for the first five years of the planning period (2013 – 2017), using a combination of existing Company-owned generation and existing long-term PPAs. As a result, the need for new resources to meet future load growth is not expected until 2018. The four expansion plans analyzed for this filing fill Nevada Power's projected open positions with diverse resource options: market purchases, conventional peaking generation, long-term toll agreements and renewable generation. Case 4, which meets Nevada Power's needs with renewable generation in excess of the RPS, satisfies the requirement for at least one low carbon intensity plan.

Also included in each of the expansion plans were existing and planned renewable resources to meet Nevada's RPS. The forecasts of renewable energy requirements and the renewable expansion plan are described in the Renewable Energy Planning Section above.

All expansion plans include the availability of wholesale market purchases in the production cost modeling as necessary to meet the system capacity requirements (see Figures EA-18 through EA-20, "Open Positions"). Regional market purchases were priced at the purchase power price forecast. As explained in the Load Forecast and Market Fundamentals Volume, the power price forecast also included a monthly capacity charge associated with firm purchases to fill the projected open positions during the peak load summer period. This capacity charge was adjusted in each expansion plan in accordance with the size of the open positions. Each of the expansion plans includes a different mix open positions (i.e., market purchases) and firm resources. Selecting the Preferred Plan and Alternative Plan necessarily requires an assessment of the price and reliability risks inherent in relying on market purchases to fill open positions.

As described below a variety of generation resource mixes were analyzed across a diverse set of sensitivities including load level, unit in service dates, unit types, fuel and purchased power price assumptions, and the other factors described in this section. Nevada Power is not proposing any resource additions in this resource plan during the action plan period other than that contained its demand-side management plan. Impacts of changes in unit availability are included in the PROMOD simulations as a function of the forced outage rate modeled for each unit and the Monte Carlo simulation of unit forced outages. The amount of required purchased power and the capacity of plants vary by plan.

The following is a list of the four expansion plans, identified as Cases 1 – 4, that were evaluated under the base load forecast. The characteristics of the new resources are described in Section 1 above.

Common Resource Additions in Cases 1 - 4

- For Nevada Power and Sierra:

- The addition of the ON Line as one 500 kV transmission line from Robinson Summit substation (interconnection with Sierra's system) to the Harry Allen substation (interconnection with Nevada Power's system) with an in-service date of January 2014, and nominal transfer capacity of 600 MW.

- For Nevada Power:
  - 1x1 CC units in 2022, 2034, 2038, 2039, and 2041
  - 2x1 CC units in 2024, 2026, 2035, 2039, 2040, 2 units in 2042
  - Three GE 7EA CTs in 2023
  - Six GE LMS 100 CTs in 2030 and 2040
  - Three GE LMS 100 CTs in 2032 and 2036

- For Sierra:
  - 1x1 CC units in 2023
  - 2x1 CC units in 2025
  - Seven GE 7EA CTs in 2022
  - Four GE LMS 100 CTs in 2032

<u>Case 1</u> – Market Purchase Case
- Common Resource Additions (above)
- Nine GE 7EA CTs in 2021

<u>Case 2</u> – Self Build CTs in 2018
- Common Resource Additions (above)
- Five GE 7EA CTs in 2018
- Nine GE 7EA CTs in 2021

<u>Case 3</u> – Long-Term Tolling Agreement
- Common Resource Additions (above)
- Five GE 7EA CTs in 2021
- Four GE 7EA CTs in 2028

<u>Case 4</u> – Self Build Southern Nevada Renewables in 2018
- Common Resource Additions (above)
- Five Solar Photovoltaic facilities in 2018 (Southern NV, 20 MW nameplate per facility, total of 100 MW)
- Two Wind facilities in 2018 (Southern NV, 72 MW nameplate per facility, total of 144 MW)
- Nine GE 7EA CTs in 2021

A detailed listing of all generation additions for each expansion plan is provided in Figures EA-1 through EA-3 below for the base, high and low load forecast scenarios. Assumed renewable PPAs for each plan are not shown in these tables but are included in Technical Appendix Item CON-1.

FIGURE EA-1 - BASE LOAD EXPANSION PLANS

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NEVADA POWER EXPANSION PLANS - BASE LOAD

CASE 1 ALL Market	CASE 2 Self Build CTs	CASE 3 275 Toll MW	CASE 4 Renewables Self Build
			(5) 20 MW PV - 2018
	(5) 7EAs - 2018	CC Toll x 275 MW 2018 - 2027	(2) 72 - MW Wind -2018
(9) 7EAs - 2021	(9) 7EAs - 2021	(5) 7EAs - 2021	(9) 7EAs - 2021
		(4) 7EAs - 2028	
1x1 CC - 2022	1x1 CC - 2022	1x1 CC - 2022	1x1 CC - 2022
(3) 7EAs - 2023	(3) 7EAs - 2023	(3) 7EAs - 2023	(3) 7EAs - 2023
2x1 CC - 2024	2x1 CC - 2024	2x1 CC - 2024	2x1 CC - 2024
2x1 CC - 2026	2x1 CC - 2026	2x1 CC - 2026	2x1 CC - 2026
(6) LMS 100 - 2030	(6) LMS 100 - 2030	(6) LMS 100 - 2030	(6) LMS 100 - 2030
(3) LMS 100 - 2032	(3) LMS 100 - 2032	(3) LMS 100 - 2032	(3) LMS 100 - 2032
1x1 CC - 2034	1x1 CC - 2034	1x1 CC - 2034	1x1 CC - 2034
2x1 CC - 2035	2x1 CC - 2035	2x1 CC - 2035	2x1 CC - 2035
(3) LMS 100 - 2036	(3) LMS 100 - 2036	(3) LMS 100 - 2036	(3) LMS 100 - 2036
1x1 CC - 2038	1x1 CC - 2038	1x1 CC - 2038	1x1 CC - 2038
1x1 CC-2039	1x1 CC -2039	1x1 CC -2039	1x1 CC-2039
2x1 CC - 2039	2x1 CC - 2039	2x1 CC - 2039	2x1 CC - 2039
2x1 CC - 2040	2x1 CC - 2040	2x1 CC - 2040	2x1 CC - 2040
(3) LMS 100 - 2040	(3) LMS 100 - 2040	(3) LMS 100 - 2040	(3) LMS 100 - 2040
(3) LMS 100 - 2040	(3) LMS 100 - 2040	(3) LMS 100 - 2040	(3) LMS 100 - 2040
1x1 CC - 2041	1x1 CC - 2041	1x1 CC - 2041	1x1 CC - 2041
2x1 CC - 2042	2x1 CC - 2042	2x1 CC - 2042	2x1 CC - 2042
2x1 CC - 2042	2x1 CC - 2042	2x1 CC - 2042	2x1 CC - 2042

SIERRA PACIFIC POWER EXPANSION PLANS - BASE LOAD

CASE 1 ALL Market	CASE 2 Self Build CTs	CASE 3 275 Toll MW	CASE 4 Renewables Self Build
(7) 7EAs - 2022	(7) 7EAs - 2022	(7) 7EAs - 2022	(7) 7EAs - 2022
1x1 CC - 2023	1x1 CC - 2023	1x1 CC - 2023	1x1 CC - 2023
2x1 CC - 2025	2x1 CC - 2025	2x1 CC - 2025	2x1 CC - 2025
(4) LMS 100 - 2032	(4) LMS 100 - 2032	(4) LMS 100 - 2032	(4) LMS 100 - 2032

FIGURE EA-2 - HIGH LOAD EXPANSION PLANS

NPC IRP JULY 1 2012 FILING

NEVADA POWER EXPANSION PLANS - HIGH LOAD

CASE 1 ALL Market	CASE 2 Self Build CTs	CASE 3 275 Toll MW	CASE 4 Renewables Self Build
(4) 7EA - 2018	(9) 7EA - 2018		(4) 7EA - 2018
		CC Toll x 275 MW 2018 - 2027	(5) 20 MW PV - 2018
		(4) 7EA - 2028	(2) 72 - MW Wind -2018
(9) 7EAs - 2021	(9) 7EAs - 2021	(9) 7EAs - 2021	(9) 7EAs - 2021
2x1 CC - 2022	2x1 CC - 2022	2x1 CC - 2022	2x1 CC - 2022
(3) 7EAs - 2023	(3) 7EAs - 2023	(3) 7EAs - 2023	(3) 7EAs - 2023
2x1 CC - 2022	2x1 CC - 2022	2x1 CC - 2022	2x1 CC - 2022
(3) LMS 100 - 2025	(3) LMS 100 - 2025	(3) LMS 100 - 2025	(3) LMS 100 - 2025
2x1 CC - 2026	2x1 CC - 2026	2x1 CC - 2026	2x1 CC - 2026
(6) LMS 100 - 2030	(6) LMS 100 - 2030	(6) LMS 100 - 2030	(6) LMS 100 - 2030
2x1 CC - 2033	2x1 CC - 2033	2x1 CC - 2033	2x1 CC - 2033
2x1 CC - 2035	2x1 CC - 2035	2x1 CC - 2035	2x1 CC - 2035
(3) LMS 100 - 2036	(3) LMS 100 - 2036	(3) LMS 100 - 2036	(3) LMS 100 - 2036
1x1 CC - 2038	1x1 CC - 2038	1x1 CC - 2038	1x1 CC - 2038
1x1 CC -2039	1x1 CC -2039	1x1 CC -2039	1x1 CC -2039
2x1 CC - 2039	2x1 CC - 2039	2x1 CC - 2039	2x1 CC - 2039
2x1 CC - 2040	2x1 CC - 2040	2x1 CC - 2040	2x1 CC - 2040
(3) LMS 100 - 2040	(3) LMS 100 - 2040	(3) LMS 100 - 2040	(3) LMS 100 - 2040
(6) LMS 100 - 2040	(6) LMS 100 - 2040	(6) LMS 100 - 2040	(6) LMS 100 - 2040
1x1 CC - 2041	1x1 CC - 2041	1x1 CC - 2041	1x1 CC - 2041
2x1 CC - 2042	2x1 CC - 2042	2x1 CC - 2042	2x1 CC - 2042
2x1 CC - 2042	2x1 CC - 2042	2x1 CC - 2042	2x1 CC - 2042

SIERRA PACIFIC POWER EXPANSION PLANS - HIGH LOAD

CASE 1 All Market	CASE 2 Self Build CT's	CASE 3 275 MW Toll	CASE 4 Renewables Self Build
(7) 7EAs - 2022	(7) 7EAs - 2022	(7) 7EAs - 2022	(7) 7EAs - 2022
1x1 CC - 2023	1x1 CC - 2023	1x1 CC - 2023	1x1 CC - 2023
2x1 CC - 2025	2x1 CC - 2025	2x1 CC - 2025	2x1 CC - 2025
(4) LMS 100 - 2032	(4) LMS 100 - 2032	(4) LMS 100 - 2032	(4) LMS 100 - 2032

FIGURE EA-3 - LOW LOAD EXPANSION PLANS

NPC IRP JULY 1 2012 FILING

NEVADA POWER EXPANSION PLANS - LOW LOAD

CASE 1	CASE 2	CASE 3	CASE 4
ALL Market	Self Build CTs	275 Toll MW	Renewables Self Build
			(5) 20 MW PV - 2018
	(5) 7EAs - 2018	CC Toll x 275 MW 2018 - 2027	(2) 72 - MW Wind -2018
(9) 7EAs - 2021	(3) 7EAs - 2021	(3) 7EAs - 2028	(3) 7EAs - 2021
1x1 CC - 2022	1x1 CC - 2022	1x1 CC - 2022	1x1 CC - 2022
(3) 7EAs - 2023	(3) 7EAs - 2023	(3) 7EAs - 2023	(3) 7EAs - 2023
2x1 CC - 2024	2x1 CC - 2024	2x1 CC - 2024	2x1 CC - 2024
2x1 CC - 2026	2x1 CC - 2026	2x1 CC - 2026	2x1 CC - 2026
(3) LMS 100 - 2030	(3) LMS 100 - 2030	(3) LMS 100 - 2030	(3) LMS 100 - 2030
(3) LMS 100 - 2032	(3) LMS 100 - 2032	(3) LMS 100 - 2032	(3) LMS 100 - 2032
1x1 CC - 2034	1x1 CC - 2034	1x1 CC - 2034	1x1 CC - 2034
2x1 CC - 2035	2x1 CC - 2035	2x1 CC - 2035	2x1 CC - 2035
1x1 CC - 2038	1x1 CC - 2038	1x1 CC - 2038	1x1 CC - 2038
1x1 CC -2039	1x1 CC -2039	1x1 CC -2039	1x1 CC -2039
2x1 CC - 2039	2x1 CC - 2039	2x1 CC - 2039	2x1 CC - 2039
(3) LMS 100 - 2040	(3) LMS 100 - 2040	(3) LMS 100 - 2040	(3) LMS 100 - 2040
(3) LMS 100 - 2040	(3) LMS 100 - 2040	(3) LMS 100 - 2040	(3) LMS 100 - 2040
2x1 CC - 2040	2x1 CC - 2040	2x1 CC - 2040	2x1 CC - 2040
1x1 CC - 2041	1x1 CC - 2041	1x1 CC - 2041	1x1 CC - 2041
2x1 CC - 2042	2x1 CC - 2042	2x1 CC - 2042	2x1 CC - 2042
2x1 CC - 2042	2x1 CC - 2042	2x1 CC - 2042	2x1 CC - 2042
	2x1 CC - 2042	2x1 CC - 2042	2x1 CC - 2042

SIERRA PACIFIC POWER EXPANSION PLANS - LOW LOAD

CASE 1	CASE 2	CASE 3	
ALL Market	Self Build CTs	275 Toll MW	Renewables Self Build
(3) 7EAs - 2022	(3) 7EAs - 2022	(3) 7EAs - 2022	(3) 7EAs - 2022
1x1 CC - 2023	1x1 CC - 2023	1x1 CC - 2023	1x1 CC - 2023
1x1 CC - 2025	1x1 CC - 2025	1x1 CC - 2025	1x1 CC - 2025
(2) LMS 100 - 2026	(2) LMS 100 - 2026	(2) LMS 100 - 2026	(2) LMS 100 - 2026
(2) LMS 100 - 2032	(2) LMS 100 - 2032	(2) LMS 100 - 2032	(2) LMS 100 - 2032
(2) LMS 100 - 2035	(2) LMS 100 - 2035	(2) LMS 100 - 2035	(2) LMS 100 - 2035

3. MODELING OF SNWA CONTRACT EXTENSION

Once the least cost plan was determined, it was further analyzed with and without the proposed Second Power Exchange Agreement with SNWA. Details of this agreement are provided in Section 2.B.5 of this narrative.

4. MODELING WITH AND WITHOUT EXTERNAL SALES

In order to determine the effect of external system sales on the revenue requirements, each case was run both with and without external system sales. Nevada Power does not justify new generation resource additions on the basis of external system sales. However, due to the overall low capacity factor of the Nevada Power system, there will be periods during which resources that are required to meet peak load will be available for off system sales. Revenues from these sales offset some of the revenue requirements for a new resource addition and are captured in cases with external system sales.

5. SCENARIO ANALYSES

NAC 704.9475 requires the utility to conduct an analysis of sensitivity for all major assumptions and estimates used in the resource plan. A range of forecasts for base, high, and low loads, high and low natural gas, coal, and purchase power prices, and a range of future potential carbon scenarios are incorporated into the cases using PROMOD to perform the analysis. Resource additions as presented in the Loads and Resources tables vary under the high and low load sensitivities.

As described above, sensitivity analyses of the alternative plans also were conducted with high and low F&PP sensitivities and a range of potential future GHG cap-and-trade programs (referred to as mid, high, low, and no carbon cases). Twelve sensitivities were prepared to evaluate each of the alternative plans under varying future conditions, as shown in Figure EA-4. The twelve sensitivities were each run with and without regional power sales as described in the following section, for a total of twenty-four sensitivities.

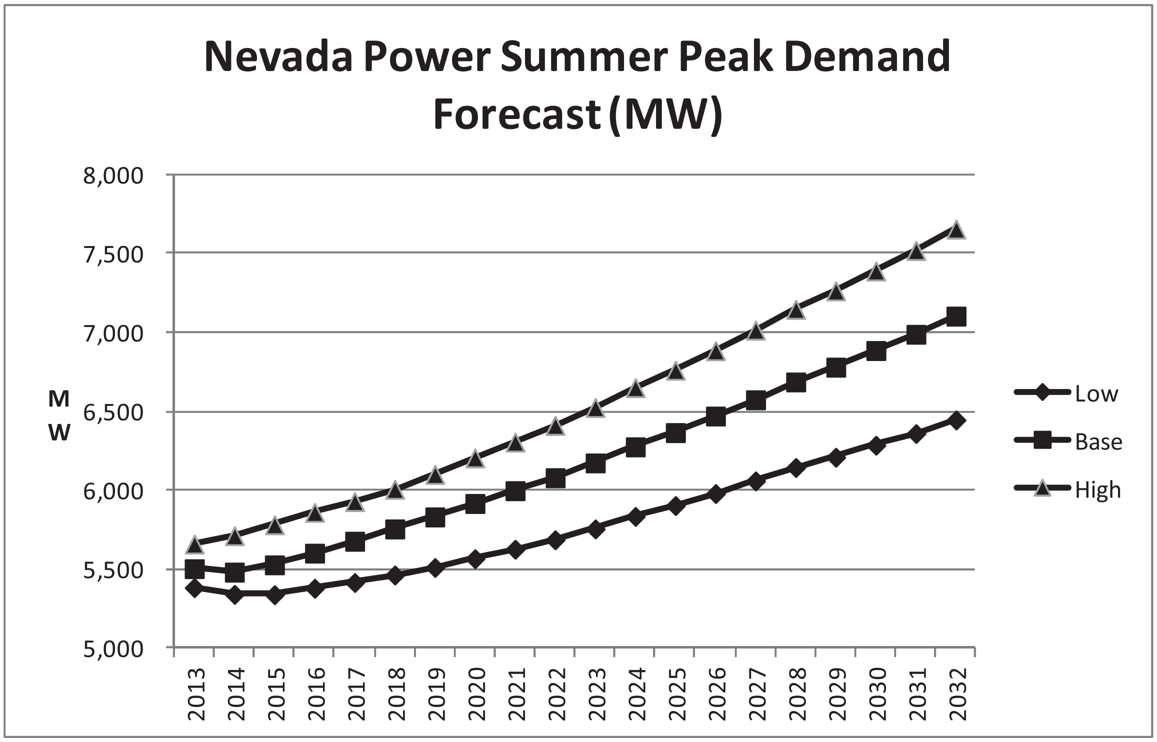
FIGURE EA-4 EXPANSION PLAN – SENSITIVITY CASES

Load	Fuel	GHG
	BASE	MID C
BASE	LOW	MID C
	HIGH	MID C
HIGH	BASE	MID C
LOW	BASE	MID C
	BASE	NO C
BASE	LOW	NO C
	HIGH	NO C
HIGH	BASE	NO C
LOW	BASE	NO C
BASE	BASE	HIGH
BASE	BASE	LOW

Multiple scenarios were created to evaluate the benefit of the various expansion plans under varying F&PP scenarios. As described in the Load Forecast and Market Fundamentals volume, high and low F&PP forecasts were developed. The results of these analyses show the relative benefit of the expansion alternatives with varying levels of market prices. Each expansion plan also was evaluated for the base F&PP forecasts with high and low load forecasts. All cases also were evaluated with and without the effects of a GHG cap-and-trade program. The base load and base F&PP cases were evaluated with no, low, mid and high levels of GHG effects. The high and low load and high and low F&PP scenarios were evaluated with no and mid GHG effects. The GHG effects were included in the PROMOD modeling and are reflected in the dispatch cost. The two lowest cost plans were then updated to include the proposed SNWA power exchange. These plans were evaluated assuming the base, high, and low load forecasts as well as with no and mid-levels of GHG effects. All cases also were run with and without external system sales. In all, a total of 110 different cases were run.

Figure EA-5 below shows the base, low and high summer peak demand for Nevada Power.

FIGURE EA-5 LOAD FORECAST SCENARIOS-SUMMER PEAK, DECEMBER FORECAST



Confidential Figure EA-6 illustrates the base, low, high price natural gas price forecast at Rockies, and confidential Figure EA-7 shows the base, low, high natural gas price forecast at SOCAL. Figure EA-8 shows on-peak purchase power costs at Mead that were modeled in the sensitivity analyses. Confidential Figure EA-9 shows the mid, low, and high GHG allowance price forecasts that were modeled in the sensitivity analyses. Coal prices were also input as base, low and high fuel forecasts sensitivities, and these confidential price forecasts can be found in Section 3.G of the Load Forecast, Market Fundamentals, and Fuel and Purchase Power Price narrative.

FIGURE EA-6 - NATURAL GAS PRICE FORECAST AT ROCKIES (REDACTED)

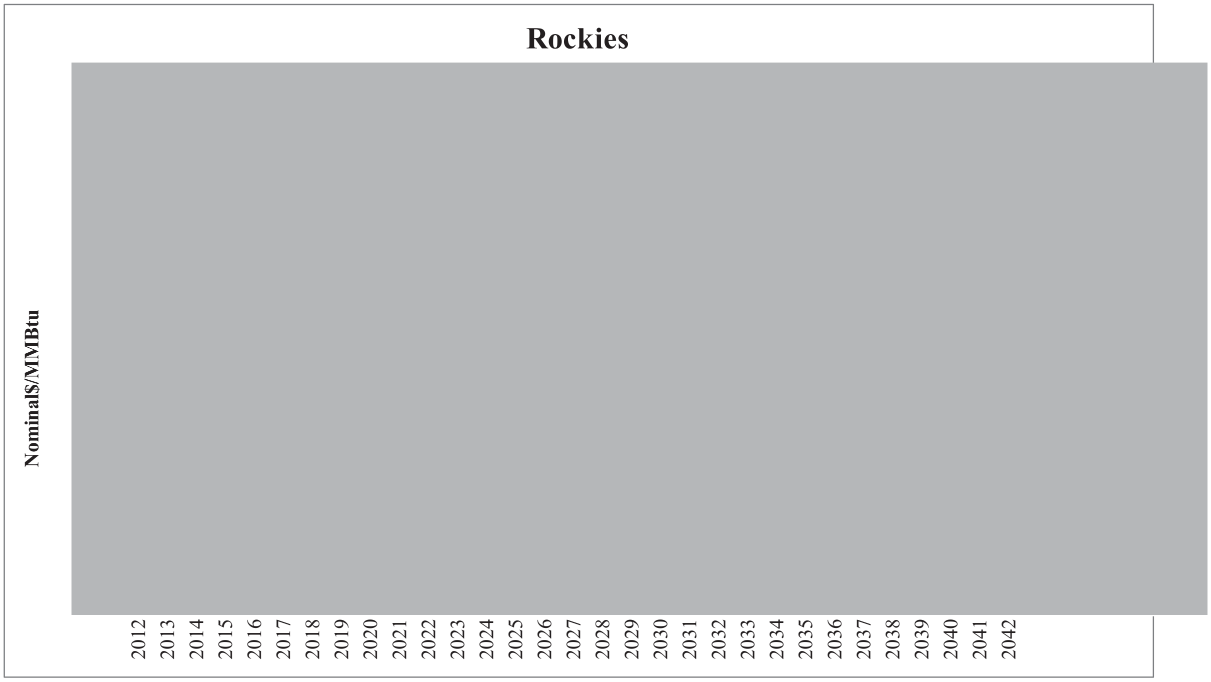


FIGURE EA-7 - NATURAL GAS PRICE FORECAST AT SOCAL (REDACTED)

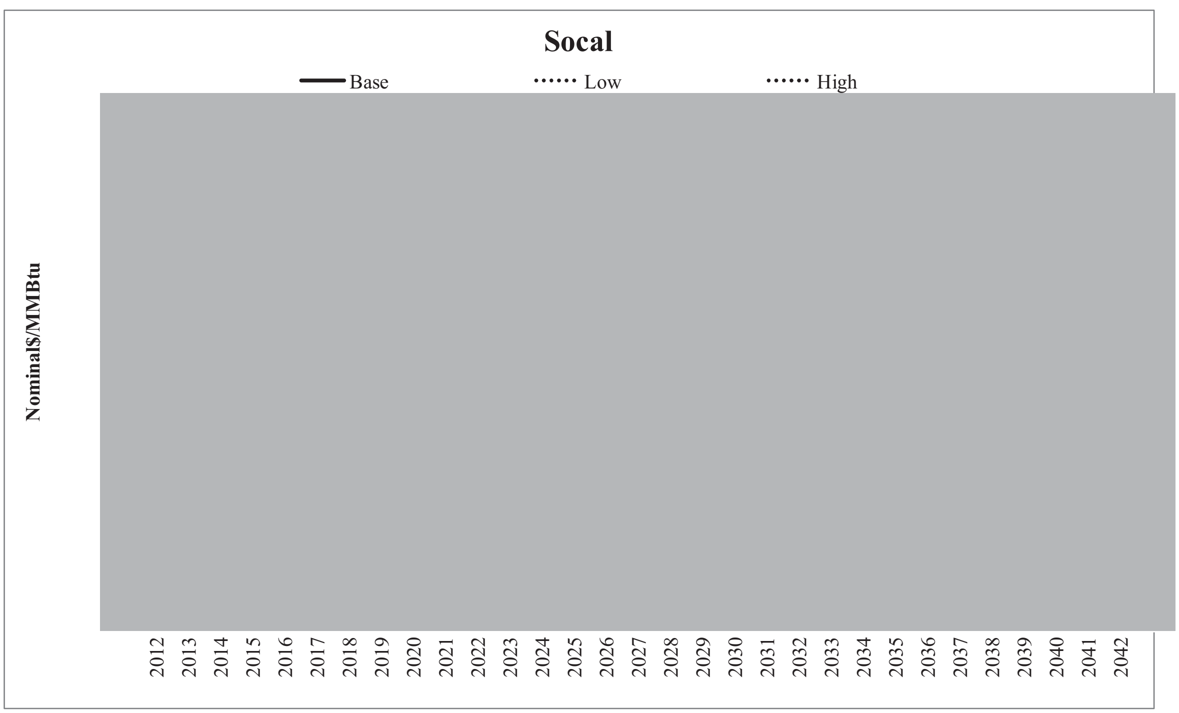


FIGURE EA-8 - PURCHASED POWER PRICE FORECAST AT MEAD (REDACTED)

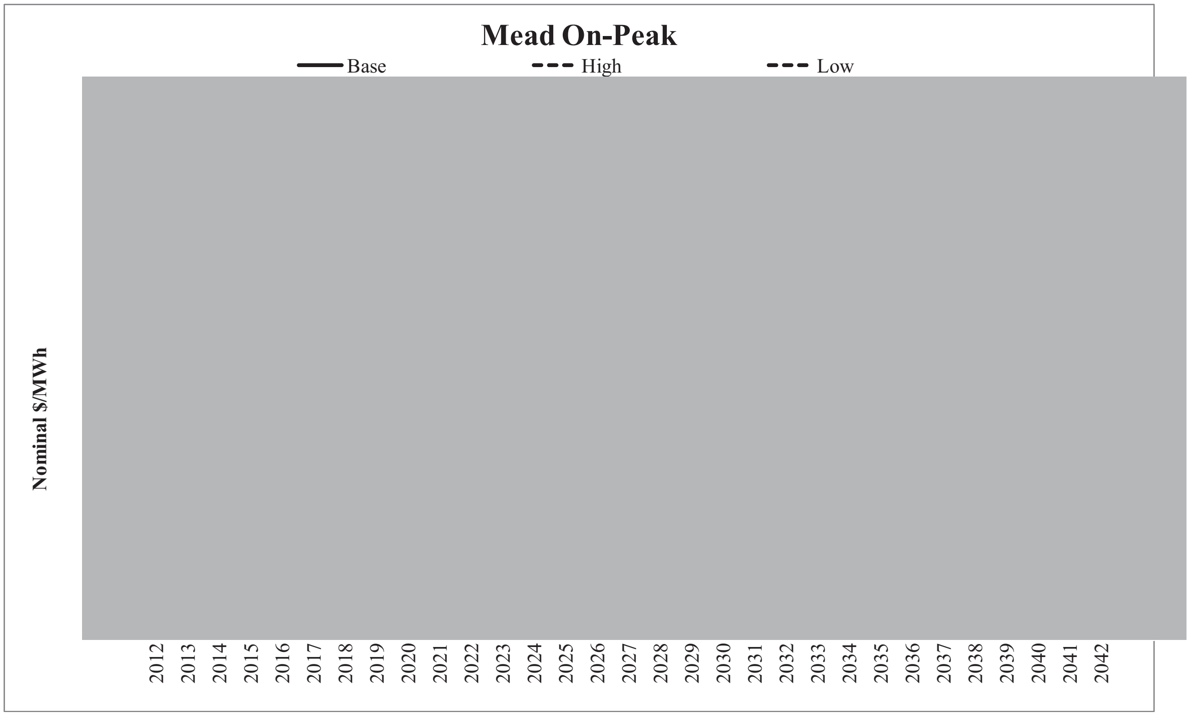
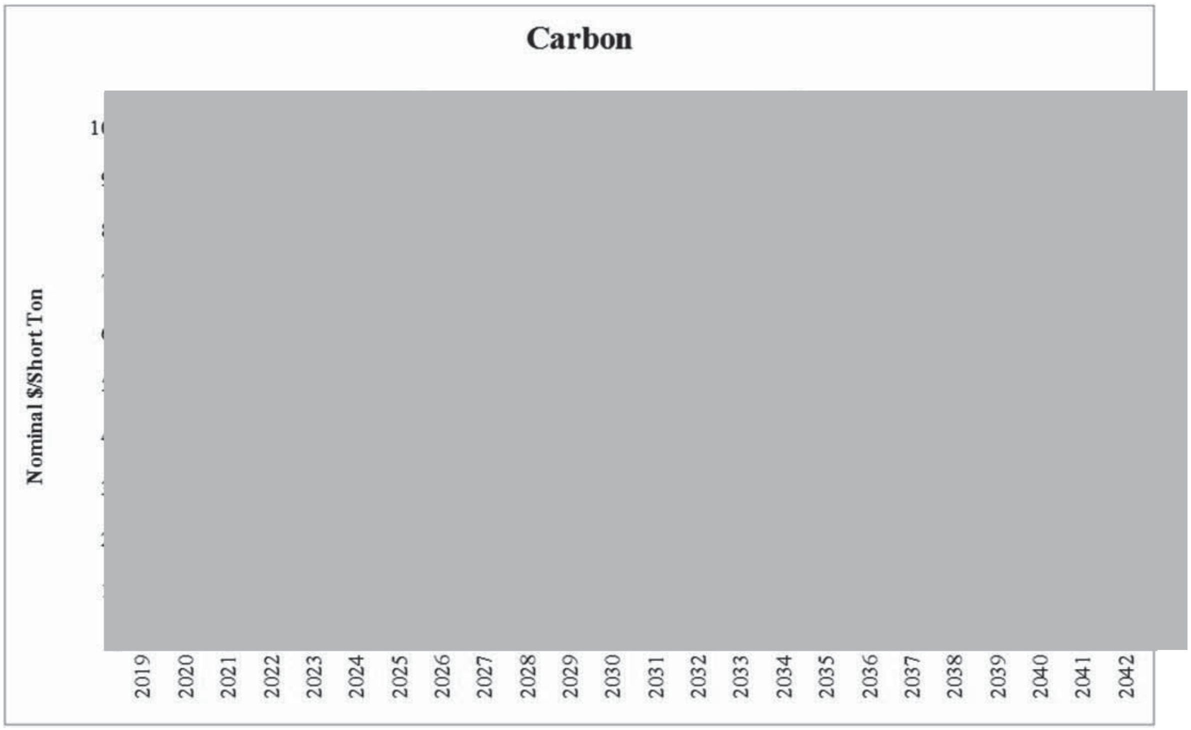


FIGURE EA-9 - GREENHOUSE GAS ALLOWANCE PRICE CASES (REDACTED)



C. ECONOMIC ANALYSES RESULTS

Figures EA-10 through 17, below, compare the 5-, 10-, 20-, and 30-year PWRR for all cases under all sensitivity cases. The additional scenarios which evaluate the SNWA Power Exchange can be found in the Technical Appendix ECON-25 (with sales) and ECON-27 (no sales) CON-2.

- For all scenarios analyzed without external system sales, the case with both the lowest 20- and 30-year PWRR is case 2, "Self-Build CTs."

- The results assuming base load, all F&PP scenarios and all GHG scenarios without external system sales, show the second lowest 20-year PWRR is Case 3, "275 MW Toll in 2018." The second lowest 30-year PWRR is Case 1, "All Market."

- For the high load, base F&PP, mid and no GHG scenarios without external system sales, the case with the second lowest 20- and 30-year PWRR is Case 3.

- For the low load, base F&PP, mid and no GHG scenarios without external system sales, the case with the second lowest 20- and 30-year PWRR is Case 1.

- For all scenarios analyzed without external system sales, the case with the highest 10-, 20-, and 30-PWRR is Case 4, "Self Build with Renewables." This result is due, in part, to the additional reserve requirements for the variable generation modeled in this case.

- Case 2 and Case 3 were evaluated further including the proposed SNWA power exchange. The rank of these cases did not change with the addition of this agreement.

The complete economic analyses for all scenarios that were evaluated,, are provided in Technical Appendices Items ECON-19 through ECON-22, and ECON-24 through ECON-27. Worksheets supporting generating input assumptions can be found in Technical Appendix Items GEN-1, GEN-4, GEN-5.

A summary of CERs for the BASE Load, BASE, LOW and HIGH Fuel and Mid, High and NO GHG scenarios are shown in Figures EA-10 through EA-17.

FIGURE EA-10 - SUMMARY-BASE LOAD FORECAST WITH BASE FUEL AND PURCHASED POWER WITHOUT EXTERNAL SALES – MID GHG

BASE LOAD BASE FUEL MID CARBON

Case	Description	5 Year PWRR 2013-2017 (million $)	10 Year PWRR 2013-2022 (million $)	20 Year PWRR 2013-2032 (million $)	30 Year PWRR 2013-2042 (million $)	5 Year PWRR Increase vs Least Cost (million $)	10 Year PWRR Increase vs Least Cost (million $)	20 Year PWRR Increase vs Least Cost (million $)	30 Year PWRR Increase vs Least Cost (million $)
CASE 1 - All Market	All Market	$ 7,420	$ 14,161	$ 26,047	**$ 35,517**	$ -	$ -	$ 67	**$ 159**
CASE 2 - Self Build CTs 7EA	2018 5-CTs 7EAs (312 MW)	$ 7,420	$ 14,191	$ 25,980	**$ 35,358**	$ -	$ 30	$ -	**$ -**
Case 3 - 275 MW Toll through 2027	275 MW Toll through 2027	$ 7,470	$ 14,179	$ 26,035	**$ 35,537**	$ 50	$ 18	$ 55	**$ 179**
CASE 4 - Self Build Renewables	2018 100 MW PV & 144 MW Wind SNV	$ 7,420	$ 14,304	$ 26,270	**$ 35,715**	$ -	$ 143	$ 290	**$ 357**

FIGURE EA-11 - SUMMARY-BASE LOAD FORECAST WITH BASE FUEL AND PURCHASED POWER WITHOUT EXTERNAL SALES – NO GHG

BASE LOAD HIGH FUEL NO CARBON

Case	Description	5 Year PWRR 2013-2017 (million $)	10 Year PWRR 2013-2022 (million $)	20 Year PWRR 2013-2032 (million $)	30 Year PWRR 2013-2042 (million $)	5 Year PWRR Increase vs Least Cost (million $)	10 Year PWRR Increase vs Least Cost (million $)	20 Year PWRR Increase vs Least Cost (million $)	30 Year PWRR Increase vs Least Cost (million $)
CASE 1 - All Market	All Market	$ 7,336	$ 13,870	$ 25,461	**$ 34,427**	$ -	$ -	$ 67	**$ 159**
CASE 2 - Self Build CTs 7EA	2018 5-CT's 7EAs (312 MW)	$ 7,336	$ 13,900	$ 25,394	**$ 34,268**	$ -	$ 30	$ -	**$ -**
Case 3 - 275 MW Toll through 2027	275 MW Toll through 2027	$ 7,386	$ 13,889	$ 25,451	**$ 34,449**	$ 50	$ 19	$ 57	**$ 181**
CASE 4 - Self Build Renewables	2018 100 MW PV & 144 MW Wind SNV	$ 7,336	$ 14,212	$ 26,155	**$ 35,238**	$ -	$ 342	$ 761	**$ 969**

FIGURE EA-12 - SUMMARY-BASE LOAD FORECAST WITH BASE FUEL AND PURCHASED POWER WITHOUT EXTERNAL SALES – HIGH GHG

BASE LOAD BASE FUEL HIGH CARBON

Case	Description	5 Year PWRR 2013-2017 (million $)	10 Year PWRR 2013-2022 (million $)	20 Year PWRR 2013-2032 (million $)	30 Year PWRR 2013-2042 (million $)	5 Year PWRR Increase vs Least Cost (million $)	10 Year PWRR Increase vs Least Cost (million $)	20 Year PWRR Increase vs Least Cost (million $)	30 Year PWRR Increase vs Least Cost (million $)
CASE 1 - All Market	All Market	$ 7,609	$ 14,705	$ 26,798	**$ 36,912**	$ -	$ -	$ 66	**$ 157**
CASE 2 - Self Build CTs 7EA	2018 5-CT's 7EAs (312 MW)	$ 7,609	$ 14,735	$ 26,733	**$ 36,755**	$ -	$ 30	$ -	**$ -**
Case 3 - 275 MW Toll through 2027	275 MW Toll through 2027	$ 7,657	$ 14,714	$ 26,774	**$ 36,920**	$ 47	$ 9	$ 42	**$ 165**
CASE 4 - Self Build Renewables	2018 100 MW PV & 144 MW Wind SNV Self Build	$ 7,609	$ 14,833	$ 26,985	**$ 37,057**	$ -	$ 129	$ 252	**$ 302**

FIGURE EA-13 - SUMMARY-BASE LOAD FORECAST WITH BASE FUEL AND PURCHASED POWER WITHOUT EXTERNAL SALES – LOW GHG

BASE LOAD BASE FUEL LOW CARBON

Case	Description	5 Year PWRR 2013-2017 (million $)	10 Year PWRR 2013-2022 (million $)	20 Year PWRR 2013-2032 (million $)	30 Year PWRR 2013-2042 (million $)	5 Year PWRR Increase vs Least Cost (million $)	10 Year PWRR Increase vs Least Cost (million $)	20 Year PWRR Increase vs Least Cost (million $)	30 Year PWRR Increase vs Least Cost (million $)
CASE 1 - All Market	All Market	$ 7,395	$ 14,027	$ 25,588	**$ 34,617**	$ -	$ -	$ 67	**$ 159**
CASE 2 - Self Build CTs 7EA	2018 5-CT's 7EAs (312 MW)	$ 7,395	$ 14,057	$ 25,520	**$ 34,458**	$ -	$ 30	$ -	**$ -**
Case 3 - 275 MW Toll through 2027	275 MW Toll through 2027	$ 7,444	$ 14,043	$ 25,573	**$ 34,635**	$ 49	$ 15	$ 53	**$ 177**
CASE 4 - Self Build Renewables	2018 100 MW PV & 144 MW Wind SNV Self Build	$ 7,395	$ 14,175	$ 25,823	**$ 34,833**	$ -	$ 148	$ 302	**$ 375**

FIGURE EA-14 - SUMMARY- BASE LOAD FORECAST WITH HIGH FUEL AND PURCHASED POWER WITHOUT EXTERNAL SALES – MID GHG

BASE LOAD HIGH FUEL MID CARBON

Case	Description	5 Year PWRR 2013-2017 (million $)	10 Year PWRR 2013-2022 (million $)	20 Year PWRR 2013-2032 (million $)	30 Year PWRR 2013-2042 (million $)	5 Year PWRR Increase vs Least Cost (million $)	10 Year PWRR Increase vs Least Cost (million $)	20 Year PWRR Increase vs Least Cost (million $)	30 Year PWRR Increase vs Least Cost (million $)
CASE 1 - All Market	All Market	$ 8,371	$ 16,216	$ 30,843	**$ 43,048**	$ -	$ -	$ 67	**$ 160**
CASE 2 - Self Build CTs 7EA	2018 5-CT's 7EAs (312 MW)	$ 8,371	$ 16,246	$ 30,776	**$ 42,888**	$ -	$ 30	$ -	**$ -**
Case 3 - 275 MW Toll through 2027	275 MW Toll through 2027	$ 8,420	$ 16,230	$ 30,823	**$ 43,059**	$ 49	$ 14	$ 47	**$ 171**
CASE 4 - Self Build Renewables	2018 100 MW PV & 144 MW Wind SNV	$ 8,371	$ 16,327	$ 30,971	**$ 43,099**	$ -	$ 111	$ 196	**$ 211**

FIGURE EA-15 - SUMMARY- BASE LOAD FORECAST WITH HIGH FUEL AND PURCHASED POWER WITHOUT EXTERNAL SALES – NO GHG

BASE LOAD HIGH FUEL NO CARBON

Case	Description	5 Year PWRR 2013-2017 (million $)	10 Year PWRR 2013-2022 (million $)	20 Year PWRR 2013-2032 (million $)	30 Year PWRR 2013-2042 (million $)	5 Year PWRR Increase vs Least Cost (million $)	10 Year PWRR Increase vs Least Cost (million $)	20 Year PWRR Increase vs Least Cost (million $)	30 Year PWRR Increase vs Least Cost (million $)
CASE 1 - All Market	All Market	$ 8,311	$ 15,914	$ 30,317	**$ 42,136**	$ -	$ -	$ 67	**$ 159**
CASE 2 - Self Build CTs 7EA	2018 5-CT's 7EAs (312 MW)	$ 8,311	$ 15,945	$ 30,250	**$ 41,976**	$ -	$ 30	$ -	**$ -**
Case 3 - 275 MW Toll through 2027	275 MW Toll through 2027	$ 8,361	$ 15,930	$ 30,301	**$ 42,151**	$ 50	$ 16	$ 51	**$ 175**
CASE 4 - Self Build Renewables	2018 100 MW PV & 144 MW Wind SNV	$ 8,311	$ 16,229	$ 30,927	**$ 42,813**	$ -	$ 314	$ 677	**$ 837**

FIGURE EA-16 - SUMMARY- BASE LOAD FORECAST WITH LOW FUEL AND PURCHASED POWER WITHOUT EXTERNAL SALES – MID GHG

BASE LOAD LOW FUEL MID CARBON

Case	Description	5 Year PWRR 2013-2017 (million $)	10 Year PWRR 2013-2022 (million $)	20 Year PWRR 2013-2032 (million $)	30 Year PWRR 2013-2042 (million $)	5 Year PWRR Increase vs Least Cost (million $)	10 Year PWRR Increase vs Least Cost (million $)	20 Year PWRR Increase vs Least Cost (million $)	30 Year PWRR Increase vs Least Cost (million $)
CASE 1 - All Market	All Market	$ 6,325	$ 11,859	$ 20,711	**$ 27,187**	$ -	$ -	$ 71	**$ 164**
CASE 2 - Self Build CTs 7EA	2018 5-CT's 7EAs (312 MW)	$ 6,325	$ 11,887	$ 20,640	**$ 27,023**	$ -	$ 28	$ -	**$ -**
Case 3 - 275 MW Toll through 2027	275 MW Toll through 2027	$ 6,375	$ 11,877	$ 20,704	**$ 27,211**	$ 50	$ 18	$ 63	**$ 188**
CASE 4 - Self Build Renewables	2018 100 MW PV & 144 MW Wind SNV	$ 6,325	$ 12,031	$ 21,020	**$ 27,522**	$ -	$ 173	$ 380	**$ 499**

FIGURE EA-17 - SUMMARY- BASE LOAD FORECAST WITH LOW FUEL AND PURCHASED POWER WITHOUT EXTERNAL SALES – NO GHG

BASE LOAD LOW FUEL NO CARBON

Case	Description	5 Year PWRR 2013-2017 (million $)	10 Year PWRR 2013-2022 (million $)	20 Year PWRR 2013-2032 (million $)	30 Year PWRR 2013-2042 (million $)	5 Year PWRR Increase vs Least Cost (million $)	10 Year PWRR Increase vs Least Cost (million $)	20 Year PWRR Increase vs Least Cost (million $)	30 Year PWRR Increase vs Least Cost (million $)
CASE 1 - All Market	All Market	$ 6,284	$ 11,651	$ 20,231	**$ 26,054**	$ -	$ -	$ 71	**$ 163**
CASE 2 - Self Build CTs 7EA	2018 5-CT's 7EAs (312 MW)	$ 6,284	$ 11,679	$ 20,160	**$ 25,891**	$ -	$ 28	$ -	**$ -**
Case 3 - 275 MW Toll through 2027	275 MW Toll through 2027	$ 6,335	$ 11,672	$ 20,227	**$ 26,082**	$ 50	$ 21	$ 67	**$ 191**
CASE 4 - Self Build Renewables	2018 100 MW PV & 144 MW Wind SNV	$ 6,284	$ 12,024	$ 21,016	**$ 27,010**	$ -	$ 373	$ 856	**$ 1,119**

D. SELECTION OF PREFERRED AND ALTERNATIVE PLANS

NAC 704.948 requires that "a utility shall analyze its decisions, taking into account its assessment of risk and identifying particular risks with respect to: (a) costs, (b) reliability, (c) finances, (d) the volatility of the price of purchased power and fuel, and (e) any other uncertainties the utility has identified." The Preferred Plan was chosen after assessing case sensitivities around loads, fuel prices, and future carbon price scenarios. The analysis shows that Case 2 is the lowest cost alternatives over the range of potential scenarios for GHG price effects. It also provides operating flexibility and minimizes third party risk. The Preferred Plan is designed to maintain the reliability of Nevada Power electric system. Financial risks are addressed in Section 4 below.

Case 2 (Self Build CTs in 2018) has the lowest cost PWRR over both twenty and thirty years compared to Cases 1, 3, and 4. When the SNWA Power Exchange agreement is added to Case 2, the overall PWRR is further reduced. As described in Section 3.H below, Case 2 also has the lowest Present Worth of Societal Cost ("PWSC"). Based in large part on its PWRR and PWSC ranking, Case 2 has been selected as the Company's Preferred Plan.

The relative closeness in the 10- and 20-year PWRR results between Cases 1, 2, and 3, is driven by the key input variables to the energy and capital modeling. That is, Nevada Power's need for additional supply side resources occurs just prior to a large upturn in the forecast price for purchased capacity. Coincidentally, the estimated cost to construct new conventional turbine technologies has dropped and performance characteristics have improved. Therefore, the Company's forecast price to construct new generation in the 2018 time frame is on par with the forecast price to purchase the same resource from the market.

In addition to its PWRR benefit, Case 2 offers the additional reliability inherent in ownership of an asset. Given the size of the open position in 2018, Case 2 better addresses the risks inherent on relying on the open market (i.e., third parties) to make resources available to support future purchases (Cases 1 and 3). Case 2 has the added benefit of offering a hedge against the uncertainties of supply assets as discussed in the Generation narrative.

It should be emphasized that Nevada Power is not requesting authority to proceed with the construction of any of these future generating units at this time.

Case 3 (275 MW Toll with 7EA CTs in 2021) was selected as the Alternative Plan. Under base case assumptions (base load, base F&PP, mid GHG price, no external system sales), the twenty year PWRR for Case 3, which relies on a firm tolling agreement instead of company built resources, is \$55 million higher than the Preferred Plan. The plan ranked third, Case 1 (All Market) is only \$12 million higher than Case 3. Over thirty years, Cases 1 and 3 change order, with Case 1 being lower than Case 3 by \$20 million. These results suggest the tolling agreement is priced near the forecast market price. Looking at the PWSC analysis, the 30-year gap between Case 3 and Case 1 is approximately \$19 million. Although the costs of Case 1 and Case 3 are similar, their reliability is different. Case 3 requires the dedication of the capacity of an existing generator for 20 years, while Case 1 assumes the market will have sufficient capacity to allow the annual purchase of needed capacity. When the SNWA Power exchange agreement is added to Case 3, the PWRR is further reduced.

Pursuant to NAC 704.945(2), the available resources and forecast of the open capacity position under the Preferred Plan are shown in Figure EA-18 through EA-20 below. Additionally, Figure EA-19 shows the open position without programs for conservation and demand management, and Figure EA-20 shows the open position without planned resources.

FIGURE EA-18 PREFERRED PLAN 2010-2030

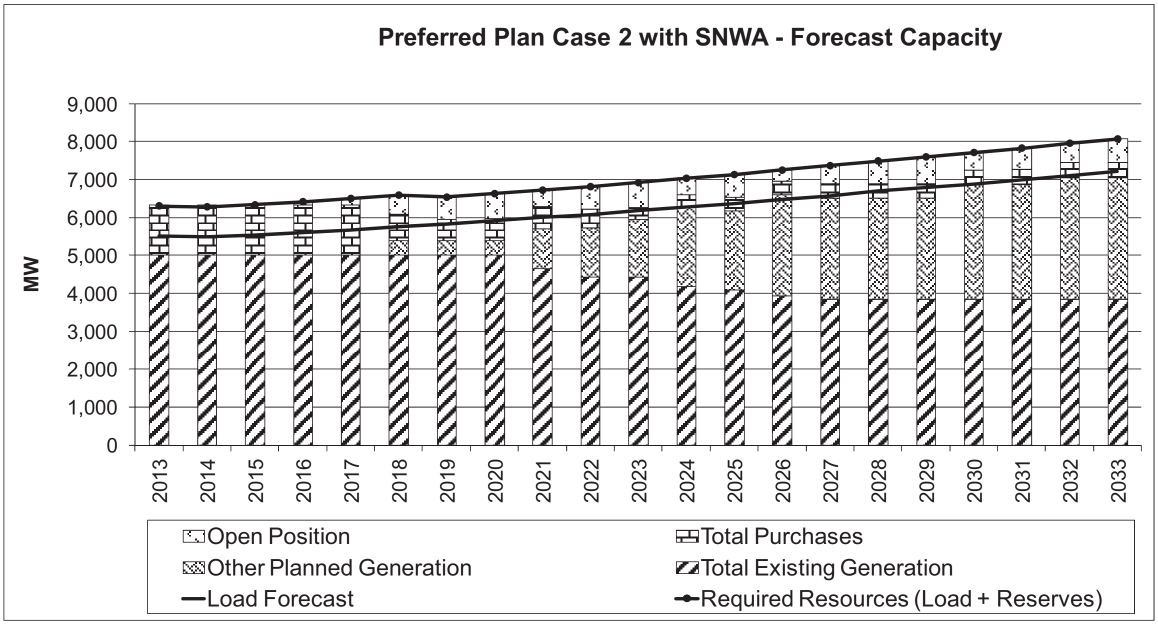


FIGURE EA-19 PREFERRED PLAN 2010-2030 – NO DSM/ACLM

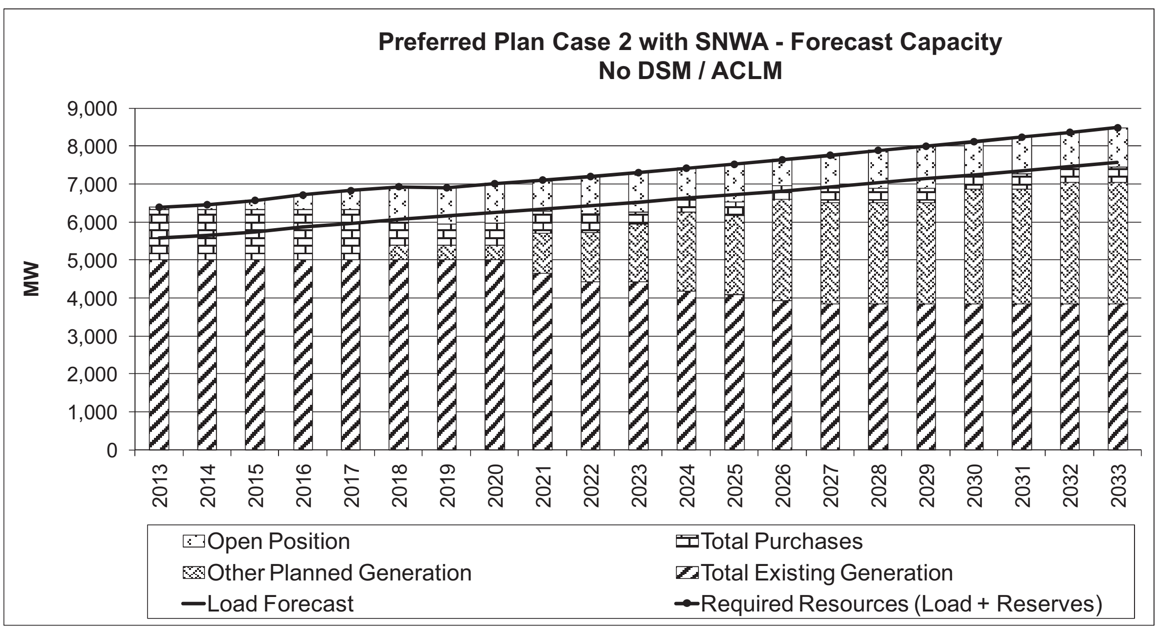
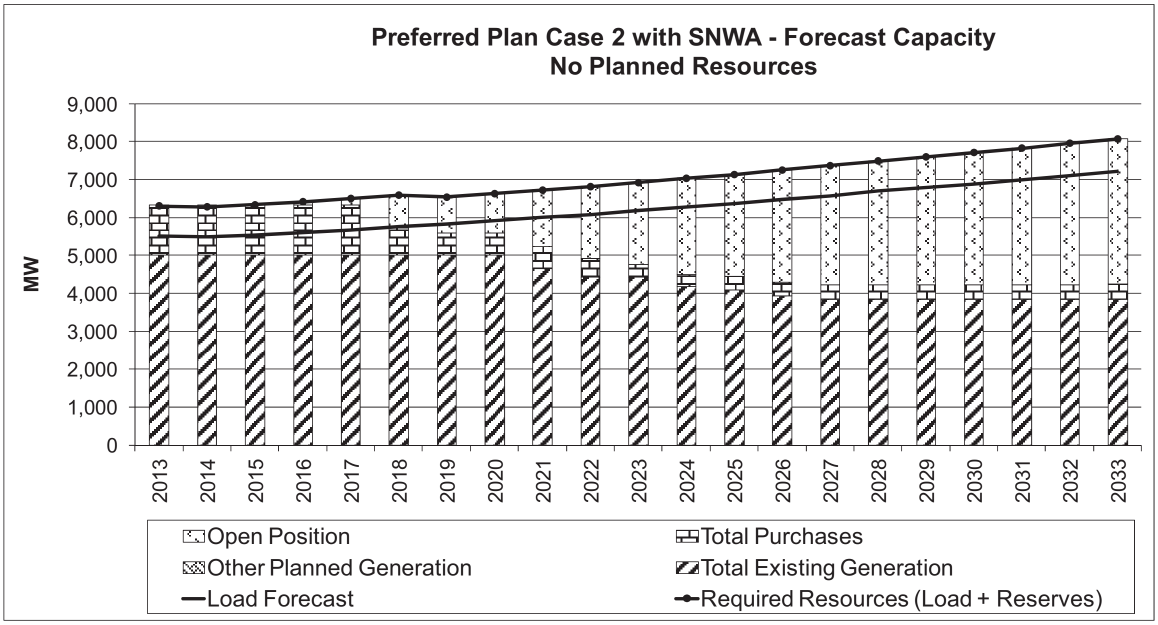


FIGURE EA-20 PREFERRED PLAN 2010-2030 – NO PLANNED RESOURCES



F. HIGH AND LOW DSM CASES

Nevada Power has prepared base (DSM Preferred Plan), high (DSM Maximum Net Benefits Alternative Plan) and low (DSM Minimum Impact Alternative Plan) DSM plans, which are described in Section 2 of the DSM Narrative. The impact on rates associated with the DSM Preferred Plan is presented in the Financial Plan Section.

In order to demonstrate the impact of higher and lower levels of DSM, the high and low DSM plans were incorporated into the resource plan using the base load forecast, which included the base DSM plan. The incremental changes in the thirty-year load forecast with high and low DSM plans is shown in Figure LF-51 of Technical Appendix LF-1

Loads and Resources tables were prepared with the high and low DSM forecasts; and are provided as Technical Appendix items ECON-9/ECON-13 and ECON-8/ECON-14, respectively. Production costs were then estimated for the Preferred Plan using PROMOD; and are provided as Technical Appendix items ECON-17 and ECON-18.

G. LOW CARBON INTENSITY PLAN

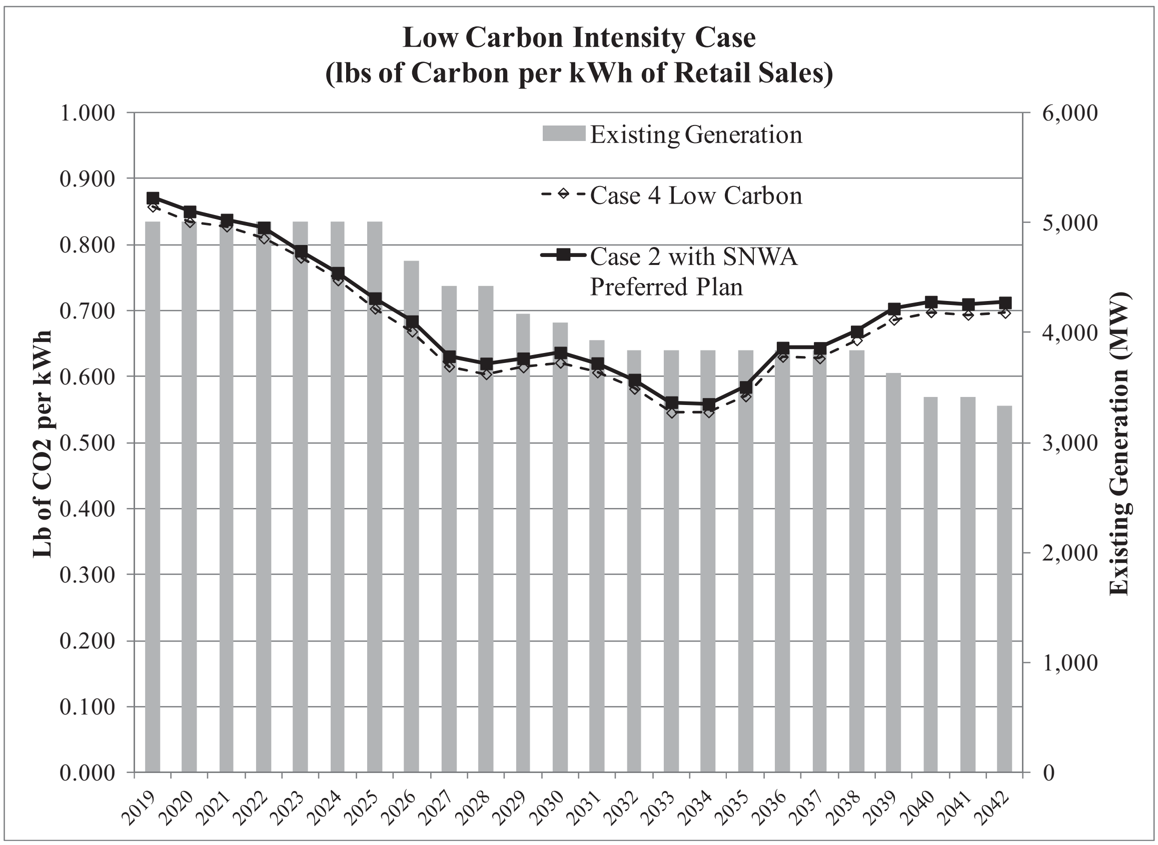
NAC §704.9355(1)(e) and NAC 704.937(1), which implement legislative changes to NRS §704.741, state that a utility must include in its supply plan at least one alternative plan of "low carbon intensity." A low carbon intensity plan is defined as:

- The generation of acquisition of an amount of renewable energy greater than required by the RPS;

- Changes to the utility's existing fleet of resources for the generation of power;
- The application of technology that would significantly reduce emissions of carbon; or
- Any combination thereof.

The Company has complied with NRS §704.741, NAC §704.9355(1)(e) and NAC 704.937(1) with Case 4, which meets Nevada Power's identified future needs with Company-owned renewable generation in an amount in excess of that required by the RPS. The carbon intensity of the Preferred and Renewable Plans is depicted in Figure EA-21. Nevada Power's overall projected carbon intensity declines over time as existing units are retired and replaced. Due to joint dispatch of the electric system, carbon intensity is expressed on a combined basis for Nevada Power and Sierra.

FIGURE EA-21 LOW CARBON INTENSITY GRAPH



E. LOADS AND RESOURCES TABLES

NAC 704.945 requires a table of loads and resources for each supply plan analyzed. For the Preferred Plan, the thirty-year projection of summer peak demand, wholesale sales, demand-side resources, reserve requirements, and generation and contract resources (existing and planned) is provided in Figures LR-1A through LR-1D. Loads and Resources tables were also developed for the alternative expansion plans, and are provided in Technical Appendix ECON-7 through ECON-16.

1. OVERVIEW

The Loads and Resources ("L&R") tables provide the expected peak load forecasts (in MW) of the Companies and the capacity resources (in MW) available to meet the peak forecast demand. The load forecast includes wholesale firm sales and is net of demand side management, demand response, and Renewable Generations net metering programs. Other loads, such as AB 661 customers, provide their own supply-side resources and thus are not included in the load that the Companies plan to serve. Planning reserve margins of 15% for Sierra and 12% for Nevada Power are added to net load requirements to yield the total required resources to serve customer peak demand. The reserve margins assure reliability: *i.e.*, that sufficient supply-side capacity (including purchase power contracts, generation, and transmission) will be available to meet the expected peak demand forecast.

Supply-side resources include a combination of existing and planned generation, and purchase power contracts (both renewable and non-renewable). The capacity value assigned to supply-side resources represents the expected available capacity of each resource at when customer demand peaks. For renewable projects that are proposed but are not yet constructed, the capacity values are further adjusted as discussed below.

The L&R tables also include a forecast of the Companies' transmission import capability and the expected use from transmission customers.

Overall, the L&R tables represent the diverse set of resource options maintained by the Companies to meet the expected peak demand. The L&R tables are provided in Technical Appendicies ECON-7 through ECON-16.

2. L&R TABLES & NEVADA'S RENEWABLE PORTFOLIO STANDARD

The L&R tables provide a projection of loads (demand) and the resources (capacity) that are expected to be available during the peak hour of the peak day of the year. The L&R tables address only the expectation of load for the peak hour of the peak day for the Company. Accordingly, they cannot be extrapolated to forecast retail energy sales, total renewable generator deliveries or Portfolio Credit ("PC") contributions to meet Nevada's Renewable Portfolio Standard ("RPS"), since these are based upon energy generation for a full calendar year.

The output from renewable energy projects is based on the availability of the resource at any given time and often (consider the case of solar or wind generation) cannot be managed to coincide with the Company's specific capacity requirement, or peak demand. The Company plans for the amount of generation output that can be reliably provided by any renewable project during peak. This is correlated to the energy supply that the supplier has contracted for under the PPA at that time and date, as well as historical performance and industry intelligence regarding the amount of generation capacity that can be reliably provided during such periods. Accordingly, the intermittency and resource variability require that the capacity value assigned to these renewables be adjusted from nameplate capacity to reflect the quantity of capacity can be delivered at the time of system peak. The Company uses the best information available to estimate these values, as described in Section 5 below.

3. L&R TABLES AND THE ON LINE TRANSMISSION PROJECT

For planning purposes, the ON Line transmission project is assumed to be in service connecting Sierra's and Nevada Power's systems on January 1, 2014. Nevada Power has entered into several renewable energy contracts with projects physically located in Sierra's service territory. Due to the lack of transmission infrastructure, Nevada Power currently is unable to take delivery of the energy or benefit from the capacity associated with these renewable energy contracts. Prior to ON Line being in service, these renewable resources are shown in Sierra's L&R Tables. After ON Line is in service, these resources transition to Nevada Power's L&R Table because Nevada Power will then have access to that energy and capacity.

4. NEVADA POWER'S LOADS AND RESOURCES TABLE

Figures LR-1A, LR-1B, LR-1C and LR-1D provide the Loads and Resources table for Nevada Power's Preferred Plan. The L&R table reflects the following updates as compared to the tables filed in the 1st Amendment Supplemental filing to Nevada Power's 2009 IRP, Docket No. 11-03014.

- The L&R table incorporates an updated load forecast, which the Company is seeking PUCN approval of in this filing.
- The L&R table reflects the retirement of Sunpeak Units 3, 4, and 5 at the end of 2021.
- The L&R table reflects the removal of the placeholder Toll transaction from 2018 through 2021.
- The L&R table incorporates an update to the Transmission section at the bottom of the L&R tables with respect to import capability and transmission use.
- The long-term renewable expansion plan for Sierra and Nevada Power has been updated and incorporates the new load forecast mentioned above[32].

[32] Changes to the capacity values and timing of planned units reflect:

- The proposed China Mountain wind project has been removed from the L&R table.

- Net metering load is reported as a separate line item.

- Renewable projects ACE Searchlight solar, Clayton Valley geothermal, Mountain View Solar, FRV Spectrum solar, and Dixie Meadows geothermal reflect their expected capacity values with updated Monte Carlo and Attrition Factor adjustments applied (the L&R table provided in the 1st Amendment Supplemental filing to Nevada Power's 2009 IRP did not apply these adjustments to Mountain View Solar, FRV Spectrum Solar, and Dixie Meadows geothermal since they were presented for approval).

- Updates to project status based on current information from project proponents;
- Changes in the calculation and application of the Monte Carlo adjustment and Attrition Factor as set forth in the Renewable Energy Planning section;
- Changes in the timing and size of future generic renewable placeholder projects consistent with changes in the Company's need for RPS compliance.

FIGURE LR-1A- L&R TABLE CASE 2 WITH SNWA – BASE LOAD (2013-2027)

NEVADA POWER COMPANY

2013 - 2027 NPC 2012 IRP CASE 2 BASE LOAD with SNWA Extention

Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
GROSS SYSTEM PEAK LOAD FORECAST (1) (Jan.2012 Load Forecast)	5,786	5,848	5,952	6,081	6,187	6,285	6,388	6,490	6,576	6,662	6,754	6,859	6,952	7,060	7,169
DSM	81	116	149	181	205	223	245	258	258	255	249	245	243	240	238
Net Metering	12	14	17	20	23	27	30	35	36	39	40	41	42	44	45
Demand Response	188	235	257	277	280	278	280	279	283	287	290	296	300	304	311
SYSTEM PEAK LOAD FORECAST (1) (Jan.2012 Load Forecast)	5,505	5,483	5,529	5,603	5,679	5,757	5,833	5,918	5,999	6,081	6,175	6,277	6,367	6,472	6,575
SNWA Obligation	125	125	125	125	125	125	-	-	-	-	-	-	-	-	-
NET SYSTEM PEAK LOAD	5,630	5,608	5,654	5,728	5,804	5,882	5,833	5,918	5,999	6,081	6,175	6,277	6,367	6,472	6,575
Planning Reserve Requirement (12%)	676	673	678	687	696	706	700	710	720	730	741	753	764	777	789
REQUIRED RESOURCES	6,306	6,281	6,332	6,415	6,500	6,588	6,533	6,628	6,719	6,811	6,916	7,030	7,131	7,249	7,364
RESOURCES (Itemized)															
Existing Internal Generation Facilities (Retire Date, 12/31/xx)															
Clark 4 (2020)	54	54	54	54	54	54	54	54	-	-	-	-	-	-	-
Clark 9,10 (9 - 2033, 10 - 2034)	430	430	430	430	430	430	430	430	430	430	430	430	430	430	430
Clark Peakers 11-22 (2038)	619	619	619	619	619	619	619	619	619	619	619	619	619	619	619
Goodsprings (2035)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Harry Allen 3 (2025)	72	72	72	72	72	72	72	72	72	72	72	72	72	-	-
Harry Allen 4 (2036)	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Harry Allen 5,6,7 (2046)	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484
Higgins (2039)	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530
Lenzie 1 (2041)	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551
Lenzie 2 (2041)	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551
Reid Gardner 1,2,3 (2020)	300	300	300	300	300	300	300	300	-	-	-	-	-	-	-
Reid Gardner 4 - Base (2023)	257	257	257	257	257	257	257	257	257	257	257	-	-	-	-
Reid Gardner 4 - Peaking (2023)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Silverhawk (75% Share) (2039)	390	390	390	390	390	390	390	390	390	390	390	390	390	390	390
Sunpeak 3,4,5 (2021)	222	222	222	222	222	222	222	222	222	-	-	-	-	-	-
	4,537	4,537	4,537	4,537	4,537	4,537	4,537	4,537	4,183	3,961	3,961	3,704	3,704	3,632	3,632
Existing Generation Requiring or Affecting Imports															
Hoover	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212
Navajo 1,2,3 (2024, 2025, 2026)	255	255	255	255	255	255	255	255	255	255	255	255	170	85	-
	467	467	467	467	467	467	467	467	467	467	467	467	382	297	212
Total Existing Generation	5,004	5,004	5,004	5,004	5,004	5,004	5,004	5,004	4,650	4,428	4,428	4,171	4,086	3,929	3,844
Planned Internal Generation Facilities															
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Planned Internal Generation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned Generation Facilities Requiring Import Rights															
5x_7EA_18	-	-	-	-	-	375	375	375	375	375	375	375	375	375	375
3x_7EA_21	-	-	-	-	-	-	-	-	225	225	225	225	225	225	225
6x_7EA_21	-	-	-	-	-	-	-	-	450	450	450	450	450	450	450
1x1_CC_22	-	-	-	-	-	-	-	-	-	237	237	237	237	237	237
3x_7EA_23	-	-	-	-	-	-	-	-	-	-	225	225	225	225	225
2x1_CC_24	-	-	-	-	-	-	-	-	-	-	-	576	576	576	576
2x1_CC_26	-	-	-	-	-	-	-	-	-	-	-	-	-	576	576
6x_LMS 100_30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3x_LMS 100_32	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1x1_CC_34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2x1_CC_35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3x_LMS 100_36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1x1_CC_38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1x1_CC_39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2x1_CC_39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2x1_CC_40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3x_LMS 100_40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3x_LMS 100_40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1x1_CC_41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2x1_CC_42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2x1_CC_42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Planned Generation Requiring Imports	-	-	-	-	-	375	375	375	1,050	1,287	1,512	2,088	2,088	2,664	2,664
Total Planned Generation	-	-	-	-	-	375	375	375	1,050	1,287	1,512	2,088	2,088	2,664	2,664
Less Scheduled Maintenance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL GENERATION	**5,004**	**5,004**	**5,004**	**5,004**	**5,004**	**5,379**	**5,379**	**5,379**	**5,700**	**5,715**	**5,940**	**6,259**	**6,174**	**6,593**	**6,508**

FIGURE LR-1B - L&R TABLE CASE 2 WITH SNWA– BASE LOAD (2013 – 2027)

NEVADA POWER COMPANY

2013 - 2027 NPC 2012 IRP CASE 2 BASE LOAD with SNWA Extention

	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
70																
71	Specific Purchases															
72	Qualifying Facilities															
73	NCA 1 (2022)	85	85	85	85	85	85	85	85	85	85	-	-	-	-	-
74	NCA 2 (2022)	85	85	85	85	85	85	85	85	85	85	-	-	-	-	-
75	Saguaro (2021)	90	90	90	90	90	90	90	90	90	-	-	-	-	-	-
76	Total Qualifying Facilities	260	260	260	260	260	260	260	260	260	170	-	-	-	-	-
77																
78	Contracts (Internal)															
79	LV CoGen I (2017)	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-
80	LV CoGen II (2013)	224	-	-	-	-	-	-	-	-	-	-	-	-	-	-
81	**Total Contracts (Internal)**	274	50	50	50	50	-	-	-	-	-	-	-	-	-	-
82																
83	Contracts (External)															
84	Griffith	570	570	570	570	570	-	-	-	-	-	-	-	-	-	-
85	Silverhawk (SNWA Transaction)	130	130	130	130	130	130	-	-	-	-	-	-	-	-	-
86	Solar1	50	34	34	34	34	34	34	34	34	34	34	34	34	34	34
87	ACE Searchlight	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
88	Fotowatio Apex	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
89	Republic Apex Landfill	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
90	Next Light Silver State	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
91	JsyValNP	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6
92	DsrtPkNP	-	10	7	7	7	7	7	7	7	7	7	7	7	7	7
93	FlknerNP	-	30	30	30	30	30	30	30	30	30	30	30	30	30	30
94	Gal2NP	-	7	9	9	9	9	9	9	9	9	9	9	9	9	9
95	SltWelNP	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5
96	StlWtrNP	-	15	15	15	15	15	15	15	15	15	15	15	15	15	15
97	Tuscarora	-	15	15	15	21	21	21	21	21	21	21	21	21	21	21
98	McGinness	-	15	15	15	15	15	15	15	15	15	15	15	15	15	15
99	Dixie Meadows	-	-	9	9	9	9	9	9	9	9	9	9	9	9	9
100	NextEra Mountain View	-	4	4	4	4	4	4	4	4	4	4	4	4	4	4
101	FRV Spectrum	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
102	Clayton Valley	-	7	7	7	7	7	7	7	7	7	7	7	7	7	7
103	Cresent Dunes	-	92	92	92	92	92	92	92	92	92	92	92	92	92	92
104	SpValley	-	13	13	13	13	13	13	13	13	13	13	13	13	13	13
105	WMRE Lockwood	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3
106	Future Purchases															
107	NNV Wind 200 20	-	-	-	-	-	-	-	10	10	10	10	10	10	10	10
108	NNV Wind 200 25	-	-	-	-	-	-	-	-	-	-	-	-	10	10	10
109	NGEO2 25	-	-	-	-	-	-	-	-	-	-	-	-	17	17	17
110	NGEO2 27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17
111	SNV Wind 72 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112	NGEO1_31	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
113	SNV Wind 72 33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
114	NGEO1_36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
115	NGEO1_38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
116	SNV PV60 40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
117	NGEO1 42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
118	Renewables - Subtotal	93	299	307	307	314	314	314	324	324	324	324	324	351	351	368
119	**Total Contracts (External)**	793	999	1,007	1,007	1,014	444	314	324	324	324	324	324	351	351	368
120																
121	**TOTAL GROSS PURCHASES**	1,327	1,309	1,317	1,317	1,324	704	574	584	584	494	324	324	351	351	368
122	**Less Scheduled Maintenance**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
123	**TOTAL NET PURCHASES**	1,327	1,309	1,317	1,317	1,324	704	574	584	584	494	324	324	351	351	368
124																
125	AVAILABLE RESOURCES	6,331	6,313	6,321	6,321	6,328	6,083	5,953	5,963	6,284	6,209	6,264	6,583	6,525	6,944	6,876
126																
127	OPEN POSITION	-	-	12	94	173	505	580	666	435	602	652	448	606	305	488
128																
129	LONG POSITION	25	32	-	-	-	-	-	-	-	-	-	-	-	-	-
130																
131	TRANSMISSION															
132	Balancing Area Import Transmission Capacity	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
133	Balancing Area Customer Load (2)	547	549	559	567	576	584	593	595	596	597	598	598	599	601	602
134	System Import Transmission Capacity	1,953	1,951	1,941	1,933	1,924	1,916	1,907	1,905	1,904	1,903	1,902	1,902	1,901	1,899	1,898
135	Import Capacity for Reserve Sharing (3)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
136	Transfer of Renewable Resources	4	222	230	230	236	236	236	246	246	246	246	246	273	273	291
137	Subtotal	1,949	1,729	1,711	1,703	1,688	1,680	1,671	1,659	1,657	1,656	1,656	1,656	1,628	1,626	1,608
138	Import Capacity for other Native Load Requirements	1,037	1,037	1,049	1,131	1,210	972	1,047	1,133	902	1,069	1,119	915	988	602	700
139	Import Capacity Requirement for Planned Generation	-	-	-	-	-	375	375	375	1,050	1,287	1,512	2,088	2,088	2,664	2,664
140	Estimated Available Transmission Capacity (4)	912	692	663	572	478	332	249	152	(295)	(700)	(976)	(1,347)	(1,448)	(1,640)	(1,756)

FIGURE LR-1C - L&R TABLE CASE 2 WITH SNWA– BASE LOAD (2028 – 2042)

NEVADA POWER COMPANY

2028 - 2042 NPC 2012 IRP CASE 2 BASE LOAD with SNWA Extention

Description	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
GROSS SYSTEM PEAK LOAD FORECAST (1) (Jan.2012 Load Forecast)	7,284	7,382	7,489	7,596	7,712	7,817	7,924	8,032	8,142	8,253	8,366	8,480	8,596	8,713	8,832
DSM	236	235	233	231	229	229	229	229	229	229	229	229	229	229	229
Net Metering	46	47	47	49	49	50	51	52	53	54	55	56	57	58	59
Demand Response	314	318	322	326	329	334	339	344	349	354	359	364	369	374	379
SYSTEM PEAK LOAD FORECAST (1) (Jan.2012 Load Forecast)	6,688	6,782	6,887	6,990	7,105	7,204	7,305	7,407	7,511	7,616	7,723	7,831	7,941	8,052	8,165
SNWA Obligation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NET SYSTEM PEAK LOAD	6,688	6,782	6,887	6,990	7,105	7,204	7,305	7,407	7,511	7,616	7,723	7,831	7,941	8,052	8,165
Planning Reserve Requirement (12%)	803	814	826	839	853	864	877	889	901	914	927	940	953	966	980
REQUIRED RESOURCES	7,491	7,596	7,713	7,829	7,958	8,068	8,182	8,296	8,412	8,530	8,650	8,771	8,894	9,018	9,145
RESOURCES (Itemized)															
Existing Internal Generation Facilities (Retire Date, 12/31/xx)															
Clark 4 (2020)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clark 9,10 (9 - 2033, 10 - 2034)	430	430	430	430	430	430	215	-	-	-	-	-	-	-	-
Clark Peakers 11-22 (2038)	619	619	619	619	619	619	619	619	619	619	619	-	-	-	-
Goodsprings (2035)	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-
Harry Allen 3 (2025)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Harry Allen 4 (2036)	72	72	72	72	72	72	72	72	72	-	-	-	-	-	-
Harry Allen 5,6,7 (2046)	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484
Higgins (2039)	530	530	530	530	530	530	530	530	530	530	530	530	-	-	-
Lenzie 1 (2041)	551	551	551	551	551	551	551	551	551	551	551	551	551	551	-
Lenzie 2 (2041)	551	551	551	551	551	551	551	551	551	551	551	551	551	551	-
Reid Gardner 1,2,3 (2020)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Reid Gardner 4 - Base (2023)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Reid Gardner 4 - Peaking (2023)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Silverhawk (75% Share) (2039)	390	390	390	390	390	390	390	390	390	390	390	390	-	-	-
Sunpeak 3,4,5 (2021)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	3,632	3,632	3,632	3,632	3,632	3,632	3,417	3,202	3,197	3,125	3,125	2,506	1,586	1,586	484
Existing Generation Requiring or Affecting Imports															
Hoover	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212
Navajo 1,2,3 (2024, 2025, 2026)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212
Total Existing Generation	3,844	3,844	3,844	3,844	3,844	3,844	3,629	3,414	3,409	3,337	3,337	2,718	1,798	1,798	696
Planned Internal Generation Facilities															
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Planned Internal Generation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned Generation Facilities Requiring Import Rights															
5x_7EA_18	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375
3x_7EA_21	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225
6x_7EA_21	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450
1x1_CC_22	237	237	237	237	237	237	237	237	237	237	237	237	237	237	237
3x_7EA_23	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225
2x1_CC_24	576	576	576	576	576	576	576	576	576	576	576	576	576	576	576
2x1_CC_26	576	576	576	576	576	576	576	576	576	576	576	576	576	576	576
6x_LMS 100_30	-	-	362	362	362	362	362	362	362	362	362	362	362	362	362
3x_LMS 100_32	-	-	-	-	181	181	181	181	181	181	181	181	181	181	181
1x1_CC_34	-	-	-	-	-	-	237	237	237	237	237	237	237	237	237
2x1_CC_35	-	-	-	-	-	-	-	576	576	576	576	576	576	576	576
3x_LMS 100_36	-	-	-	-	-	-	-	-	181	181	181	181	181	181	181
1x1_CC_38	-	-	-	-	-	-	-	-	-	-	237	237	237	237	237
1x1_CC_39	-	-	-	-	-	-	-	-	-	-	-	237	237	237	237
2x1_CC_39	-	-	-	-	-	-	-	-	-	-	-	576	576	576	576
2x1_CC_40	-	-	-	-	-	-	-	-	-	-	-	-	576	576	576
3x_LMS 100_40	-	-	-	-	-	-	-	-	-	-	-	-	181	181	181
3x_LMS 100_40	-	-	-	-	-	-	-	-	-	-	-	-	181	181	181
1x1_CC_41	-	-	-	-	-	-	-	-	-	-	-	-	-	237	237
2x1_CC_42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	576
2x1_CC_42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	576
Total Planned Generation Requiring Imports	2,664	2,664	3,026	3,026	3,207	3,207	3,444	4,020	4,201	4,201	4,438	5,251	6,189	6,426	7,578
Total Planned Generation	2,664	2,664	3,026	3,026	3,207	3,207	3,444	4,020	4,201	4,201	4,438	5,251	6,189	6,426	7,578
Less Scheduled Maintenance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL GENERATION	**6,508**	**6,508**	**6,870**	**6,870**	**7,051**	**7,051**	**7,073**	**7,434**	**7,610**	**7,538**	**7,775**	**7,969**	**7,987**	**8,224**	**8,274**

FIGURE LR-1D - L&R TABLE CASE 2 WITH SNWA – BASE LOAD (2028 – 2042)

NEVADA POWER COMPANY

2028 - 2042 NPC 2012 IRP CASE 2 BASE LOAD with SNWA Extention

	Description	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
70																
71	Specific Purchases															
72	Qualifying Facilities															
73	NCA 1 (2022)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
74	NCA 2 (2022)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
75	Saguaro (2021)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
76	Total Qualifying Facilities	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
77																
78	Contracts (Internal)															
79	LV CoGen I (2017)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
80	LV CoGen II (2013)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
81	**Total Contracts (Internal)**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
82																
83	Contracts (External)															
84	Griffith	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
85	Silverhawk (SNWA Transaction)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
86	Solar1	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
87	ACE Searchlight	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
88	Fotowatio Apex	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
89	Republic Apex Landfill	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
90	Next Light Silver State	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
91	JsyValNP	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
92	DsrtPkNP	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
93	FlknerNP	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
94	Gal2NP	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
95	SltWelNP	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
96	StlWtrNP	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
97	Tuscarora	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
98	McGinness	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
99	Dixie Meadows	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
100	NextEra Mountain View	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
101	FRV Spectrum	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
102	Clayton Valley	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
103	Cresent Dunes	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92
104	SpValley	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
105	WMRE Lockwood	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
106	Future Purchases															
107	NNV Wind 200 20	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
108	NNV Wind 200 25	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
109	NGEO2 25	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
110	NGEO2 27	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
111	SNV Wind 72 29	-	7	7	7	7	7	7	7	7	7	7	7	7	7	7
112	NGEO1_31	-	-	-	9	9	9	9	9	9	9	9	9	9	9	9
113	SNV Wind 72 33	-	-	-	-	-	7	7	7	7	7	7	7	7	7	7
114	NGEO1_36	-	-	-	-	-	-	-	-	9	9	9	9	9	9	9
115	NGEO1_38	-	-	-	-	-	-	-	-	-	-	9	9	9	9	9
116	SNV PV60 40	-	-	-	-	-	-	-	-	-	-	-	-	23	23	23
117	NGEO1 42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9
118	Renewables - Subtotal	368	375	375	384	384	391	391	391	400	400	408	408	431	431	440
119	**Total Contracts (External)**	368	375	375	384	384	391	391	391	400	400	408	408	431	431	440
120																
121	**TOTAL GROSS PURCHASES**	368	375	375	384	384	391	391	391	400	400	408	408	431	431	440
122	**Less Scheduled Maintenance**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
123	**TOTAL NET PURCHASES**	368	375	375	384	384	391	391	391	400	400	408	408	431	431	440
124																
125	AVAILABLE RESOURCES	6,876	6,883	7,245	7,254	7,435	7,442	7,464	7,825	8,010	7,938	8,183	8,377	8,418	8,655	8,714
126																
127	OPEN POSITION	615	713	468	575	523	627	718	471	403	592	467	394	476	363	431
128																
129	LONG POSITION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
130																
131	TRANSMISSION															
132	Balancing Area Import Transmission Capacity	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
133	Balancing Area Customer Load (2)	603	604	605	606	607	608	609	610	611	612	613	614	615	616	617
134	System Import Transmission Capacity	1,897	1,896	1,895	1,894	1,893	1,892	1,891	1,890	1,889	1,888	1,887	1,886	1,885	1,884	1,883
135	Import Capacity for Reserve Sharing (3)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
136	Transfer of Renewable Resources	291	291	291	299	299	299	299	299	308	308	316	316	316	316	325
137	Subtotal	1,607	1,605	1,604	1,595	1,594	1,593	1,592	1,591	1,581	1,580	1,570	1,569	1,568	1,567	1,558
138	Import Capacity for other Native Load Requirements	827	925	680	787	735	839	930	683	615	804	679	606	688	575	643
139	Import Capacity Requirement for Planned Generation	2,664	2,664	3,026	3,026	3,207	3,207	3,444	4,020	4,201	4,201	4,438	5,251	6,189	6,426	7,578
140	Estimated Available Transmission Capacity (4)	(1,884)	(1,983)	(2,102)	(2,219)	(2,348)	(2,453)	(2,782)	(3,112)	(3,235)	(3,426)	(3,546)	(4,287)	(5,309)	(5,434)	(6,664)

L&R Table Footnotes

(1) SNWA 125 MW contract through 2018 is NOT included in the System Peak Load Forecast.
(2) Coincident combined loads for Boulder City, CRC-BMI, City of LV SB211, LVVWD, Lincoln, Overton, East Side / Newport, SB 211, Valley Electric, City of Henderson. The Company notes that Valley Electric has requested to leave the Company's BA and join the CAISO BA. This table has not yet removed Valley Electric's load from the Company's BA.
(3) Reserve sharing assistance assumed to change from the Southwest Reserve Sharing Group (SRSG) to the Northwest Power Pool.
(4) Estimates are based on summer peak conditions only. ATC will vary by month.

5. METHODOLOGY FOR ASSIGNING L&R CAPACITY VALUES FOR FUTURE RENEWABLE PROJECTS

The L&R tables include capacity values for future renewable energy projects. The Company procures renewable energy to meet its obligations under the RPS. The L&R tables recognize that renewable energy systems serve two purposes: contributing toward the Company's compliance with the RPS, and providing capacity to meet the Company's peak demand requirements. Certain resource types are characterized as intermittent (*i.e.*, non-firm capacity) at the time of peak. The Company has assigned capacity values to future renewable resources according to the follow rules.

For non-intermittent facilities, the capacity value entered in the L&R tables is the expected capacity value as shown in the 12 x 24 hour supply tables in July at hour ending 17:00 (5 pm). For wind projects, a capacity value of ten percent of the nameplate rating is assigned for purposes of preparing the L&R tables. For PV solar projects, a capacity value of thirty-eight percent of the nameplate rating is assigned and incorporated into the L&R tables.[33] For Commission-approved PPA projects that are currently in development but not yet operating, the nameplate value assumed for all technologies reflects the adjusted value derived by applying a Monte Carlo adjustment factor and/or the Attrition Factor in the manner described in the Renewable Energy Planning Section.[34] Accordingly, the L&R table would reflect the Monte Carlo/Attrition adjusted value for non-intermittent facilities and ten percent and thirty-eight percent of the Monte Carlo/Attrition adjusted value for these wind and PV projects respectively. No Monte

[33] The thirty-eight percent capacity value across the PV portfolio is based on an analysis performed by Pacific Northwest National Laboratories using data from Nevada Power's PV Integration Study. See Docket No. 11-03014, Technical Appendix Item SUP-ECON-6.

[34] Monte Carlo and Attrition Factor are applied to projects that have not undertaken significant construction activities and obtained financing. Monte Carlo alone is applied to projects that have undertaken significant construction activities and obtained financing.

Carlo or Attrition Factor adjustment is applied to future generic renewable additions (*i.e.*, facilities included as a future placeholder to satisfy the RPS requirement).[35] A description of how the Monte Carlo adjustment and Attrition Factor are calculated and applied to the development portfolio is set forth in the Renewable Energy Planning Section.

6. L&R CAPACITY VALUES FOR RENEWABLE EXPANSION PLAN PROJECTS

The renewable expansion plan included in the L&R tables is described in Figure LR-2. Figure LR-2 provides a list of the projects, location, utility assignment (Nevada Power or Sierra), planned commercial operation date ("COD"), and how the capacity values are derived.

Projects assigned to Sierra and Nevada Power are indicated in the column, "PPA Utility". Note that projects assigned to Nevada Power and located in Sierra's service territory (column label "N/S") and with an expected in-service date prior to January 2014[36] (column label "COD") appear in Sierra's L&R tables until 2014. Similarly, Sierra's share of the Nevada Solar One facility is shown in Nevada Power's L&R tables until 2014.

Both Companies' L&R tables assume that existing contracts will expire in accordance with their terms but will be renegotiated as the most likely economic replacements to meet RPS compliance at the then-prevailing rate for that technology. This assumption differs from the L&R table in the 1st Amendment Supplemental filing to Nevada Power's 2009 IRP, where the capacity contribution of these renewable projects ended with their contract expiration dates but was assumed to be supplemented by other generic renewable projects to maintain RPS compliance.

Lastly, if the projected COD date occurs after July 1st (i.e. in time to meet peak) in a given year, its capacity will not appear until the following planning year.

The capacity values shown on the L&R tables for future renewable projects are described in Figure LR-2. The combined Monte Carlo/Attrition Factor adjustments for each project can be derived from the ratio of the right-most column ('Value on L&R') to the base capacity (depending on the resource type, 'Supply at 5pm', 'PV at 38%', or 'Wind at 10%').

[35] Future generic additions are added as needed to meet the RPS through the 30-year planning period as shown in Technical Appendix Item REN-1.
[36] Prior to the planned in-service date of the ON Line transmission project.

FIGURE LR-2 RENEWABLE EXPANSION PLAN – PREFERRED PLAN - BASE LOAD

Project	Technology	Location North/ South	Name Plate MW	COD	PPA Utility	Monte Carlo Factor	Attrition Factor	Supply table 5pm peak MW	PV at 38% of nameplate MW	Wind at 10% of nameplate MW	With Monte Carlo / Attrition MW	Value on L&R MW
Additions:												
Clayton Valley	Geo	N	53.5	Jul-2014	NPC	Yes	Yes	13	NA	NA	7	7
Dixie Meadows	Geo	N	51.0	Apr-2015	NPC	Yes	Yes	17	NA	NA	9	9
Tuscarora (Expansion)	Geo	N	25.0	Jan-2017	NPC	Yes	Yes	15	NA	NA	7	7
Geo 25.5 MW (2x)	Geo	N	51.0	Jan-2025	NPC	No	No	17	NA	NA	NA	17
Geo 25.5 MW (2x)	Geo	N	51.0	Apr-2027	NPC	No	No	17	NA	NA	NA	17
Geo 25.5 MW (1x)	Geo	N	25.5	Jul-2031	NPC	No	No	9	NA	NA	NA	9
Geo 25.5 MW (1x)	Geo	N	25.5	Sep-2035	NPC	No	No	9	NA	NA	NA	9
Geo 25.5 MW (1x)	Geo	N	25.5	Nov-2037	NPC	No	No	9	NA	NA	NA	9
Geo 25.5 MW (1x)	Geo	N	25.5	Sep-2041	NPC	No	No	9	NA	NA	NA	9
San Emidio (Expansion Option)	Geo	N	11.8	Nov-2013	SPPC	Yes	Yes	3	NA	NA	1	1
Geo 25.5 MW (1x)	Geo	N	25.5	Aug-2034	SPPC	No	No	9	NA	NA	NA	9
ACE Searchlight	Solar PV	S	17.5	Dec-2012	NPC	Yes	Yes	11	7	NA	4	4
Fotowatio Apex PV	Solar PV	S	20.0	Jun-2012	NPC	Yes	No	12	8	NA	7	7
FRV Spectrum Solar	Solar PV	S	30.0	Jul-2013	NPC	Yes	Yes	19	11	NA	7	7
NextLight Silver State	Solar PV	S	50.0	May-2012	NPC	No	No	29	19	NA	NA	19
NextEra Mountain View	Solar PV	S	20.0	Feb-2014	NPC	Yes	Yes	13	8	NA	4	4
Still Water 2 PV	Solar PV	N	22.0	Jan-2012	NPC	No	No	6	8	NA	NA	8
SolarReserve Crescent Dunes	Solar CSP	N	110.0	Dec-2013	NPC	Yes	No	100	NA	NA	92	92
PV 20 MW SN (3x)	Solar PV	S	60.0	Aug-2039	NPC	No	No	10	23	NA	NA	23
PV 20 MW NN (3x)	Solar PV	N	60.0	Jul-2036	SPPC	No	No	10	23	NA	NA	23
PV 20 MW NN (1x)	Solar PV	N	20.0	Jul-2039	SPPC	No	No	3	8	NA	NA	8
PV 20 MW NN (1x)	Solar PV	N	20.0	Aug-2041	SPPC	No	No	3	8	NA	NA	8
CC Landfill Energy	LF Gas	S	10.7	Mar-2012	NPC	No	No	7	NA	NA	NA	7
WMRE Lockwood	LF Gas	N	3.2	Mar-2012	NPC	No	No	3	NA	NA	NA	3
Spring Valley Wind	Wind	N	151.8	Jun-2012	NPC	Yes	No	42	NA	15	13	13
Wind 200 MW NN (Phased)	Wind	N	100.0	Apr-2020	NPC	No	No	22	NA	10	NA	10
Wind 200 MW NN (Phased)	Wind	N	100.0	Dec-2024	NPC	No	No	22	NA	10	NA	10
Wind 72 MW SN	Wind	S	72.0	April-2029	NPC	No	No	25	NA	7	NA	7
Wind 72 MW SN	Wind	S	72.0	May-2033	NPC	No	No	25	NA	7	NA	7
Wind 100 MW NN	Wind	N	100.0	Jan-2034	SPPC	No	No	37	NA	10	NA	10
*As of 2/29/2012												

H. ENVIRONMENTAL EXTERNALITIES AND ECONOMIC BENEFITS TO THE STATE

Nevada regulations require that Nevada Power consider environmental costs and "economic benefits" (which are generally termed "economic impacts") when analyzing expansion cases.

The regulations require the Company to rank its power supply options on the basis of the PWRR and Present Worth of Societal Costs ("PWSC"). The PWSC of a resource plan is defined as the sum of the PWRR plus "environmental costs that are not internalized as private costs to the utility…"[37] Environmental costs are defined by the Commission as "costs, wherever they may occur, that result from harm or risks of harm to the environment after the application of all mitigation measures required by existing environmental regulation or otherwise included in the resource plan."[38] In addition, the regulations state that "environmental costs to the State associated with operating and

[37] NAC § 704.937(4).

[38] NAC § 704.9359.

maintaining a supply plan or demand-side plan must be quantified for air emissions, water and land use."[39] Among these potential costs, environmental costs associated with air emissions impacts typically (and appropriately, given their relative importance) receive the most attention in the evaluation of cases. Emissions subject to a cap-and-trade program lead to financial effects that are included in the PWRR for the purposes of financial planning.

The regulations also require the Company to assess the "net economic benefits" of cases under certain circumstances, as noted below. "Economic benefits" are often referred to as "economic impacts," so that they are distinguished from other types of benefits. The net economic benefits include both the positive impacts of greater expenditures in Nevada and the negative impacts of higher electricity rates for consumers and businesses that generally accompany greater expenditures. A recent order by the Public Utility Commission of Nevada ("Commission") asks NV Energy to "evaluate its current methods and identify alternative methods for assessing the economic benefits to the State for resource alternatives that will more accurately quantify the range of economic costs and benefits in a cost-effective and practical manner."

The Company retained the services of NERA Economic Consulting ("NERA") to provide analyses of the environmental costs and economic benefits of the potential expansion cases.[40] The complete report on the analysis performed by NERA is provided in Technical Appendix ECON-23. The report provides information on environmental costs and economic benefits for the four expansion cases.

With regard to the recent Commission order asking NV Energy to evaluate alternative methodologies for assessing economic impacts, the NERA report includes discussion of the alternative methods and models that could be used to estimate economic impacts and the tradeoffs between them. In particular, accounting for the negative impacts would require that the Companies develop additional data—notably potential rate impacts—as well as a more complex and costly model and model customization process. Moreover, there is an argument for allowing the Commission to provide additional guidance after considering these trade-offs. Incorporating negative impacts—and thus developing the additional data and modeling—seems particularly appropriate when alternative cases in an IRP differ significantly in their potential electricity price effects and when the Commission is faced with an immediate decision on major capital commitments. These two conditions do not seem to hold for the current IRP, because its cases differ only slightly and the Company understands that the Commission is not being asked to make capital decisions. Moreover, using the same model as in previous filings (IMPLAN) for the current IRP would provide the Commission with the opportunity to consider the

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[39] Id.

[40] NERA is a global firm of experts who apply economic, finance and quantitative principles to complex business and legal challenges. NERA has earned wide recognition for its work in energy, environmental economics and regulation, antitrust, public utilities regulation, transportation, health care, and international trade, among other areas of expertise. References to NERA in this document relate to the authors of the NERA report; the analyses and conclusions in the NERA report represent those of the authors and do not necessarily represent those of NERA or any of its clients.

choices and provide updated guidance. NERA has therefore continued to use the relatively cost-effective IMPLAN model and estimate only the positive economic impacts of the cases. Additional information on the alternative models and methodologies is provided in the NERA report.

The report also provides information related to emissions that are currently covered or are anticipated to be covered by a cap-and-trade program. Specifically, the report provides information on sulfur dioxide (“SO_2”), which is already subject to a cap-and-trade program, and carbon dioxide (“CO_2”), which may be covered by a greenhouse gas (“GHG”) cap-and-trade program in the future. Due to the uncertainty on whether or not a GHG cap-and-trade program will be adopted, NERA modeled two scenarios: (1) a “No-carbon” price scenario in which there is assumed to be no GHG cap-and-trade program, and; (2) a “Mid-carbon” price scenario in which a cap-and-trade program with a reasonable stringency and allowance price trajectory is assumed to begin in 2019.

The information that NERA provided for the cap-and-trade programs includes estimates of potential allowance prices, revenues that NV Energy would obtain from initial allocation of allowances, and (in the case of the GHG cap-and-trade program) potential effects of the program on various fossil fuel prices (relative to NV Energy base fuel price forecasts).

1. IMPACTS OF CAP-AND-TRADE PROGRAMS FOR EMISSIONS OF SULFUR DIOXIDE AND CARBON DIOXIDE

Emissions of SO_2 from generating units in Nevada are currently covered by the Acid Rain Trading Program, a nationwide cap-and-trade program. As noted above, a cap-and-trade program for carbon dioxide and other GHG emissions is assumed to be implemented in the future under the “Mid-carbon” price scenario. Under a cap-and-trade program, total emissions from covered sources are capped. As a result, emissions from Nevada Power and Sierra generating units would not increase the overall level of emissions in the United States under the respective caps and thus would not lead to external environmental costs.

Emissions of pollutants subject to a cap-and-trade program do, however, lead to financial consequences for Nevada Power and Sierra. The Companies must have allowances sufficient to cover their emissions. The costs of these allowances—either the direct costs of purchased allowances or the opportunity costs of allowances initially allocated to NV Energy—are properly included in the PWRR based on the modeled dispatch of fossil generation units and resulting emissions. Cap-and-trade programs typically have provided some allowances to various entities for free. The value of this allowance allocation reduces the net costs incurred by Nevada Power and Sierra under a cap-and-trade program.

For the two emissions covered (or expected to be covered) by a cap-and-trade program—SO_2 and GHGs—NERA developed estimates of future allowance prices and projections of potential allowance allocations that would be received by Nevada Power and Sierra. For the GHG cap-and-trade program, NERA also developed estimates of changes in fuel prices.

Figure NERA-1 shows the present value of estimated SO_2 allowance allocations to Nevada Power and Sierra from 2013 to 2042. These allocation values are based on forecasted prices for SO_2 allowances and the allowance allocations that Nevada Power and Sierra will receive under the Acid Rain Trading Program. Since the allocations do not depend upon future activities, these allocation values are the same for all four expansion cases.

FIGURE NERA-1 PRESENT VALUE OF SO2 ALLOCATION (MILLIONS), 2013-2042

NPC	SPPC	Total
$0.53	$0.11	$0.64

Notes: All values are present values as of January 1, 2013 in millions of 2013 dollars for the period 2013-2042 using nominal annual discount rates of 8.08 percent for Nevada Power and 8.12 percent for Sierra.
Real annual values were converted to nominal annual values using annual inflation rates from the Companies' 2012 Planning Guidelines.

Figure NERA-2 shows the present values of estimated GHG allowance allocations for Nevada Power and Sierra from 2013 to 2042 based on the assumed GHG cap-and-trade program that would begin in 2019 and a formula that might be used under the program to allocate free allowances. The formula was developed using information on the allocation criteria included in the most recent Congressional proposals for a national GHG cap-and-trade program. The GHG allowance allocations reflect allowance prices under the "Mid-carbon" price scenario. Because the allocation formulas are assumed to be based on a combination of historical data and base case forecasts of future electricity sales, which do not vary across the expansion cases, the allocation values are the same for the four expansion cases.

FIGURE NERA-2 PRESENT VALUE OF GHG ALLOCATION (MILLIONS), 2013-2042

	NPC	SPPC	Total
Mid	$576	$240	$817

Notes: All values are present values as of January 1, 2013 in millions of 2013 dollars for the period 2013-2042 using nominal annual discount rates of 8.08 percent for Nevada Power and 8.12 percent for Sierra. The GHG cap-and-trade program and allowance allocation are assumed to begin in 2019.
Real annual values were converted to nominal annual values using annual inflation rates from the Companies' 2012 Planning Guidelines.

The financial impacts related to SO_2 and GHG emissions from Nevada Power and Sierra are included in the PWRR for the purposes of financial planning.

NERA also developed estimates of the changes in prices of fuels—including Henry Hub natural gas, distillate fuel oil, PRB coal, and Rocky Mountain coal—that would occur due to implementation of the potential national GHG cap-and-trade program. NERA provided this information to Nevada Power for use in its PROMOD runs. Thus, the economic effects of these fuel price changes are included in the PWRR.

2. ENVIRONMENTAL COSTS FOR AIR EMISSIONS NOT COVERED BY A CAP-AND-TRADE PROGRAM

(A). ENVIRONMENTAL COSTS FOR CONVENTIONAL AND TOXIC AIR EMISSIONS

Figure NERA-3 presents the estimated environmental costs of air emissions other than SO_2 and CO_2. This table includes environmental costs for emissions controlled to meet National Ambient Air Quality Standards ("NAAQS") and the requirements of the recent Mercury and Air Toxics Standards ("MATS") issued by the U.S. Environmental Protection Agency ("EPA") in December 2011.[41] These environmental costs were modeled for both the "No-carbon" and "Mid-carbon" price scenarios described above.

Based on the NAAQS, NERA included values for emissions of nitrogen oxides ("NO_x"), particulate matter ("PM"), volatile organic compounds ("VOC"), and carbon monoxide ("CO"). VOC environmental costs are estimated to be $0 because they do not contribute to ambient ozone concentrations in Nevada, as discussed in Technical Appendix ECON-23. CO is not monetized because the necessary site-specific data were unavailable; however, CO emissions projections are reported in Technical Appendix Item ECON-23. Based on their inclusion in the MATS regulation, emissions of mercury and hydrogen chloride ("HCl") are also included. (The MATS regulation uses PM emissions as a proxy for non-mercury metallic air toxics, but this element of the MATS regulation does not lead to additional environmental costs because PM emissions are already included based upon the NAAQS.) HCl is not monetized because EPA does not provide the relevant information in the MATS regulatory impact analysis; however, HCl emission projections are reported in Technical Appendix ECON-23.

[41] The environmental values per ton of air emissions are based in part on estimates developed by the EPA, as discussed in the NERA report. The authors of the NERA report have not evaluated the scientific and economic analyses that underlie the EPA estimates and do not endorse the values.

FIGURE NERA-3 PRESENT VALUE OF ENVIRONMENTAL COSTS (MILLIONS) FOR CONVENTIONAL AND TOXIC AIR EMISSIONS, 2013-2042

	Case 1	Case 2	Case 3	Case 4
NOx				
No Carbon	$16.66	$16.66	$16.49	$16.39
Mid Carbon	$16.97	$16.97	$16.80	$16.71
PM				
No Carbon	$183.18	$183.16	$182.85	$180.24
Mid Carbon	$183.01	$182.99	$182.71	$180.05
VOC				
No Carbon	$0.00	$0.00	$0.00	$0.00
Mid Carbon	$0.00	$0.00	$0.00	$0.00
CO				
No Carbon	-	-	-	-
Mid Carbon	-	-	-	-
Mercury				
No Carbon	$0.05	$0.05	$0.05	$0.05
Mid Carbon	$0.05	$0.05	$0.05	$0.05
HCl				
No Carbon	-	-	-	-
Mid Carbon	-	-	-	-
Total				
No Carbon	$199.89	$199.87	$199.39	$196.68
Mid Carbon	$200.04	$200.01	$199.56	$196.81

Note: All values are present values as of January 1, 2013 in millions of 2013 dollars for the period 2013-2042 using nominal annual discount rates of 8.08 percent for Nevada Power and 8.12 percent for Sierra.
Real annual values were converted to nominal annual values using annual inflation rates from the Companies' 2012 Planning Guidelines.
Total may differ from the sum of the rows due to independent rounding.
"-" denotes that the environmental costs of the air emission are not monetized.

Figure NERA-4 compares the environmental costs of conventional air emissions and air toxics with Case 2 (the Preferred Plan). Case 1 would have slightly higher environmental costs of conventional and toxic air emissions, while Cases 3 and 4 would have slightly lower costs.

FIGURE NERA-4 DIFFERENCES IN THE PRESENT VALUE OF ENVIRONMENTAL COSTS (MILLIONS) FOR CONVENTIONAL AND TOXIC AIR EMISSIONS FOR 2013-2042, RELATIVE TO CASE 2

	Case 1	Case 2	Case 3	Case 4
No Carbon	$0.02	-	-$0.48	-$3.19
Mid Carbon	$0.03	-	-$0.44	-$3.20

Note: All values are present values as of January 1, 2013 in millions of 2013 dollars for the period 2013-2042 using nominal annual discount rates of 8.08 percent for Nevada Power and 8.12 percent for Sierra.
Real annual values were converted to nominal annual values using annual inflation rates from the Companies' 2012 Planning Guidelines.

(B). Illustrative Environmental Costs for Carbon Dioxide Emissions Before Implementation of a Potential Cap-and-Trade Program

Figure NERA-5 and Figure NERA-6 provide illustrative estimates of the present value of potential environmental costs of CO_2 emissions (referred to as social cost of carbon or SCC) for the "No-carbon" and "Mid-carbon" price scenarios. The estimates are based on provisional damage values developed by the Interagency Working Group on the Social Cost of Carbon (Interagency Group), a Federal government effort to promote consistency in how CO_2 emissions are valued in regulatory impact analyses.[42] The scenarios that we display in Figure NERA-5 and Figure NERA-6 are based on global and U.S. damages,[43] and real discount rates of 3 percent and 5 percent. The 3 percent discount rate is referred to by the Interagency Group as its "central value," but the 5 percent discount rate is more comparable to the Companies' discount rates used to calculate the present value of environmental costs. As the Interagency Group notes, there are substantial uncertainties surrounding these estimates, including the nature and extent of potential adverse effects associated with carbon dioxide emissions, as well as what discount rate should be used to calculate the present value of future damages from a tonne of CO2 emitted in a given year[44] and how risk aversion should be incorporated.[45] The provisional values reported

[42] The authors of the NERA report have not evaluated the scientific and economic analyses that underlie the Interagency Group values for the social cost of carbon and do not endorse them.

[43] The Interagency Group provides global values for the social cost of carbon and recommends estimating U.S. damages using a range from 7 percent to 23 percent of the global values. This analysis uses the midpoint (15 percent) from that range.

[44] The Interagency Group provides global damage estimates for three discount rates, including 2.5 percent, 3 percent and 5 percent. If the 2.5 percent discount rate were used, the present value of global costs for the "No-carbon" scenario would be about $10 billion for all expansion cases, and U.S. costs would $1.5 billion. For the "Mid-carbon" scenario, the 2.5 percent discount rate would result in present value global costs of about $3.2 billion for all expansion cases and U.S. costs of $0.5 billion.

[45] The Interagency Group provides a fourth set of global damage values (in addition to the three sets for different discount rates), based upon the 95th percentile value and a 3 percent discount rate, which it notes is designed "to represent the higher-than-expected impacts from temperature change further out in the tails of the SCC distribution." If this set of values were used, the present value of global costs for the "No-carbon" scenario would be about $20 billion for all expansion cases, and the present value for U.S.

by the Interagency Group cover a wide range. Given the uncertainties, the wide range of potential values, and the provisional nature of the Interagency Group's results, NERA refers to the estimates of the environmental costs of CO_2 emissions as illustrative.

FIGURE NERA-5 PRESENT VALUES OF ILLUSTRATIVE ESTIMATES OF ENVIRONMENTAL COSTS (MILLIONS) FOR CARBON DIOXIDE EMISSIONS FOR THE "NO-CARBON" PRICE SCENARIO

	Real discount rate used to compute SCC			
	5%		3%	
Scope of Damages	U.S.	Global	U.S.	Global
Case 1	$269	$1,792	$982	$6,548
Case 2	$269	$1,792	$982	$6,548
Case 3	$268	$1,790	$981	$6,540
Case 4	$265	$1,766	$969	$6,459

Note: All values are present values as of January 1, 2013 in millions of 2013 dollars for the period 2013-2018 using nominal annual discount rates of 8.08 percent for Nevada Power and 8.12 percent for Sierra.
Real annual values were converted to nominal annual values using annual inflation rates from the Companies' 2012 Planning Guidelines
U.S. costs are calculated as 15 percent of global costs (the midpoint of the Interagency Group's suggested range).

FIGURE NERA-6 PRESENT VALUES OF ILLUSTRATIVE ESTIMATES OF ENVIRONMENTAL COSTS (MILLIONS) FOR CARBON DIOXIDE EMISSIONS FOR THE "MID-CARBON" PRICE SCENARIO

	Real discount rate used to compute SCC			
	5%		3%	
Scope of Damages	U.S.	Global	U.S.	Global
Case 1	$74	$492	$306	$2,042
Case 2	$74	$492	$306	$2,042
Case 3	$74	$491	$306	$2,037
Case 4	$74	$491	$306	$2,037

Note: All values are present values as of January 1, 2013 in millions of 2013 dollars for the period 2013-2018 using nominal annual discount rates of 8.08 percent for Nevada Power and 8.12 percent for Sierra.
Real annual values were converted to nominal annual values using annual inflation rates from the Companies' 2012 Planning Guidelines
U.S. costs are calculated as 15 percent of global costs (the midpoint of the Interagency Group's suggested range).

Figure NERA-7 and Figure NERA-8 compare the differences relative to Case 2 of the illustrative estimates of the environmental costs of CO_2 emissions under the "No-carbon"

costs would be $3.0 billion. For the "Mid-carbon" scenario, the present values for global costs would be about $6.2 billion for all expansion cases, and the present value of U.S. costs would be $0.9 billion.

and "Mid-carbon" price scenarios, respectively. The differences are largest for Case 4 under the "No-carbon" price scenario and are small for all cases under the "Mid-carbon" price scenario.

FIGURE NERA-7 DIFFERENCES IN PRESENT VALUES OF ILLUSTRATIVE ESTIMATES OF ENVIRONMENTAL COSTS (MILLIONS) FOR CARBON DIOXIDE EMISSIONS FOR THE "NO-CARBON" PRICE SCENARIO

	Real discount rate used to compute SCC			
	5%		3%	
Scope of Damages	U.S.	Global	U.S.	Global
Case 1	$0	$0	$0	$0
Case 2	-	-	-	-
Case 3	$0	-$2	-$1	-$8
Case 4	-$4	-$26	-$13	-$89

All values are present values as of January 1, 2013 in millions of 2013 dollars for the period 2013-2018 using nominal annual discount rates of 8.08 percent for Nevada Power and 8.12 percent for Sierra.
Real annual values were converted to nominal annual values using annual inflation rates from the Companies' 2012 Planning Guidelines.
U.S. costs are calculated as 15 percent of global costs (the midpoint of the Interagency Group's suggested range).
Values of zero indicate that the relevant difference is less than $500,000.

FIGURE NERA-8 DIFFERENCES IN PRESENT VALUES OF ILLUSTRATIVE ESTIMATES OF ENVIRONMENTAL COSTS (MILLIONS) FOR CARBON DIOXIDE EMISSIONS FOR THE "MID-CARBON" PRICE SCENARIO

	Real discount rate used to compute SCC			
	5%		3%	
Scope of Damages	U.S.	Global	U.S.	Global
Case 1	$0	$0	$0	$0
Case 2	-	-	-	-
Case 3	$0	-$1	-$1	-$5
Case 4	$0	-$1	-$1	-$5

All values are present values as of January 1, 2013 in millions of 2013 dollars for the period 2013-2018 using nominal annual discount rates of 8.08 percent for Nevada Power and 8.12 percent for Sierra.
Real annual values were converted to nominal annual values using annual inflation rates from the Companies' 2012 Planning Guidelines.
U.S. costs are calculated as 15 percent of global costs (the midpoint of the Interagency Group's suggested range).
Values of zero indicate that the relevant difference is less than $500,000.

3. OTHER ENVIRONMENTAL EFFECTS

Environmental costs related to land use and other environmental effects were not separately evaluated because any costs are likely to be highly site-specific and not likely to be significant relative to the estimated environmental costs associated with air emissions.

(A). ADDITIONAL COSTS OF WATER CONSUMPTION

NERA estimated the costs of water consumption by Nevada Power and Sierra that are not included in the PWRR. These additional costs are based upon water use from wells owned by NV Energy and do not include water that is leased or purchased, because the value of leased or purchased water is included in the PWRR. Moreover, no additional water costs are calculated for power purchased by NV Energy through contracts, renewable power purchase agreements, or spot market transactions because NERA assumes that all water costs are included in the prices that NV Energy pays and thus are included in the PWRR.

Figure NERA-9 shows the estimated additional costs of water consumption for the four expansion cases.

FIGURE NERA-9 PRESENT VALUE OF ADDITIONAL WATER COST (MILLIONS) 2013-2042

	Case 1	Case 2	Case 3	Case 4
No Carbon	$62.248	$62.246	$62.191	$62.076
Mid Carbon	$62.592	$62.573	$62.496	$62.215

Notes: All values are present values as of January 1, 2013 in millions of 2013 dollars for the period 2013-2018 using nominal annual discount rates of 8.08 percent for Nevada Power and 8.12 percent for Sierra.
Real annual values were converted to nominal annual values using annual inflation rates the Companies' 2012 Planning Guidelines.

Figure NERA-10 compares the present value of additional water costs with the additional water costs of Case 2. The differences in additional water costs reflect the differences over the four cases in the projected monthly generation projections for the plants owned by NV Energy that consume water from their own wells.

FIGURE NERA-10. DIFFERENCES IN THE PRESENT VALUE OF ADDITIONAL WATER COST (MILLIONS), 2013-2042

	Case 1	Case 2	Case 3	Case 4
No Carbon	$0.002	-	-$0.055	-$0.170
Mid Carbon	$0.019	-	-$0.077	-$0.358

Notes: All values are present values as of January 1, 2013 in millions of 2013 dollars for the period 2013-2018 using nominal annual discount rates of 8.08 percent for Nevada Power and 8.12 percent for Sierra.
Real annual values were converted to nominal annual values using annual inflation rates the Companies' 2012 Planning Guidelines.

Figure NERA-11 and Figure NERA-12 provide information on the PWSC of the four expansion cases for the "No-carbon" and "Mid-carbon" price scenarios, respectively. As noted above, PWSC is defined as the sum of the PWRR and environmental costs. The environmental costs include air emissions costs and additional water costs; the illustrative carbon dioxide environmental costs are not included in these calculations. The figures also show the net PWSC relative to Case 2 as well as the ranking of the four expansion cases. For both carbon price scenarios, Case 2 has the lowest PWSC and Case 4 has the highest PWSC.

FIGURE NERA-11 PRESENT WORTH OF SOCIAL COSTS (MILLIONS) OF THE EXPANSION CASES FOR THE "NO-CARBON" PRICE SCENARIO, 2013-2042

	Case 1	Case 2	Case 3	Case 4
PWRR	$34,426.98	$34,268.42	$34,448.93	$35,237.76
Air Emission Costs	$199.89	$199.87	$199.39	$196.68
Additional Water Costs	$62.25	$62.25	$62.19	$62.08
PWSC	$34,689.12	$34,530.54	$34,710.51	$35,496.52
PWSC Difference from Case 2	$158.59	-	$179.98	$965.98
PWSC Rank	2	1	3	4

Notes: All values are present values as of January 1, 2013 in millions of 2013 dollars for the period 2013-2042 using nominal annual discount rates of 8.08 percent for Nevada Power and 8.12 percent for Sierra.
Real annual values were converted to nominal annual values using annual inflation rates the Companies' 2012 Planning Guidelines.

FIGURE NERA-12 PRESENT WORTH OF SOCIAL COSTS (MILLIONS) OF THE EXPANSION CASES FOR THE "MID-CARBON" PRICE SCENARIO, 2013-2042

	Case 1	Case 2	Case 3	Case 4
PWRR	$35,517.30	$35,358.26	$35,536.90	$35,715.42
Air Emission Costs	$200.04	$200.01	$199.56	$196.81
Additional Water Costs	$62.59	$62.57	$62.50	$62.21
PWSC	$35,779.93	$35,620.84	$35,798.96	$35,974.45
PWSC Difference from Case 2	$159.10	-	$178.13	$353.61
PWSC Rank	2	1	3	4

Notes: All values are present values as of January 1, 2013 in millions of 2013 dollars for the period 2013-2042 using nominal annual discount rates of 8.08 percent for Nevada Power and 8.12 percent for Sierra.
Real annual values were converted to nominal annual values using annual inflation rates the Companies' 2011 Planning Guidelines.

4. Economic Benefits of Expansion Cases

Figure NERA-13 summarizes the estimates NERA developed of the potential "economic benefits" (economic impacts) of the four expansion cases assuming base load, base fuel prices, and the "Mid-carbon" price scenario. As noted above, these estimates are based upon the use of IMPLAN to model the positive effects of increased expenditures in Nevada and exclude estimates of the potential negative effects of higher electricity rates. The NERA report provides information on the model and methodology that could be used to estimate negative rate impacts as well as the rationale for concluding that IMPLAN would be an appropriate modeling approach in this IRP.

The total positive economic impact for each case is the sum of construction effects and operation effects. Economic impacts are characterized by four measures: (1) Nevada Gross State Product, which measures the increased value added from goods and services in Nevada; (2) Nevada employment; (3) Nevada personal income; and (4) Nevada state and local tax revenues.[46]

The economic impact estimates reflect the effects of expenditures and employment within Nevada resulting from construction and operation under each of the expansion cases. These estimates include the direct effects of construction and annual operations as well as the indirect and induced effects from interactions among industries and households in Nevada. Note that the NERA methodology assumes that purchased power does not result in additional expenditures in Nevada on the expectation that the generation would come from facilities outside Nevada. It is important to note that these "economic benefits" in Nevada are distinct from the environmental costs and thus are not comparable.

[46] Tax revenue excludes property taxes for reasons discussed in the NERA Report.

FIGURE NERA-13. PRESENT VALUE OF "ECONOMIC BENEFITS"

		Case 1	Case 2	Case 3	Case 4
Gross State Product	million $, PV	$5,777	$5,725	$5,906	$6,000
Employment	job-years	217,817	213,002	221,309	222,361
Personal Labor Income	million $, PV	$3,984	$3,947	$4,070	$4,141
State and Local Taxes	million $, PV	$311	$308	$318	$323

Note: Present values are as of January 1, 2013 in millions of 2013 dollars for the period 2013-2042 using a nominal annual discount rate of 8.08 percent.
Job-years are expressed as a non-discounted sum.

Figure NERA-14 compares the present values of "economic benefits" with Case 2. The larger economic impacts for other cases reflect the additional expenditures in Nevada for the other cases. As emphasized above, these economic impact results do not include effects on economic activity in Nevada of any differences in electricity rates due to implementation of the various expansion cases.

FIGURE NERA-14 DIFFERENCES IN THE PRESENT VALUE OF "ECONOMIC BENEFITS"

		Case 1	Case 2	Case 3	Case 4
Gross State Product	million $, PV	$52	-	$181	$275
Employment	job-years	4,815	-	8,307	9,359
Personal Labor Income	million $, PV	$37	-	$124	$195
State and Local Taxes	million $, PV	$3	-	$10	$15

Note: Present values are as of January 1, 2013 in millions of 2013 dollars for the period 2013-2042 using a nominal annual discount rate of 8.08 percent.
Job-years are expressed as a non-discounted sum.

I. LONG-TERM AVOIDED COSTS METHODOLOGY

For purposes of determining the long-term avoided cost to be offered to QFs under PURPA, the avoided cost is determined by examining Nevada Power's "open position" in future years. For the purpose of this filing Nevada Power calculated the long-term avoided cost based on the hourly marginal costs from a PROMOD simulation for the Preferred Plan, assuming the open position is filled with market purchases. During the July - September period the capacity charge included in the market price forecast was added to the on peak hourly marginal energy cost.

FIGURE LT- 1 LONG-TERM AVOIDED COST RATE CALCULATION

($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
2013	$ 27.32	$ 27.20	$ 28.05	$ 25.46	$ 27.10	$ 29.88	$ 35.99	$ 36.07	$ 34.42	$ 27.53	$ 28.56	$ 28.79	$ 29.70
2014	$ 31.74	$ 30.87	$ 31.67	$ 28.94	$ 30.74	$ 33.66	$ 40.74	$ 40.58	$ 37.80	$ 35.93	$ 34.71	$ 34.84	$ 34.35
2015	$ 34.42	$ 34.32	$ 35.43	$ 32.38	$ 34.01	$ 37.56	$ 44.33	$ 44.11	$ 40.83	$ 34.86	$ 36.44	$ 39.78	$ 37.37
2016	$ 41.05	$ 41.19	$ 40.14	$ 37.15	$ 37.47	$ 41.96	$ 49.39	$ 48.58	$ 44.18	$ 37.42	$ 38.72	$ 41.48	$ 41.56
2017	$ 43.51	$ 44.02	$ 41.61	$ 38.75	$ 39.24	$ 52.95	$ 59.79	$ 59.46	$ 54.32	$ 40.14	$ 41.42	$ 42.53	$ 46.48
2018	$ 43.95	$ 43.87	$ 42.73	$ 39.83	$ 39.50	$ 59.13	$ 65.44	$ 67.41	$ 62.42	$ 39.92	$ 42.75	$ 43.49	$ 49.20
2019	$ 51.09	$ 48.52	$ 47.60	$ 44.33	$ 45.89	$ 91.14	$ 100.36	$ 99.47	$ 93.97	$ 48.41	$ 47.42	$ 48.95	$ 63.93
2020	$ 50.83	$ 47.90	$ 47.69	$ 45.72	$ 46.45	$ 114.49	$ 126.18	$ 121.44	$ 118.96	$ 47.64	$ 47.86	$ 52.30	$ 72.29
2021	$ 52.75	$ 51.99	$ 49.65	$ 46.41	$ 47.49	$ 138.85	$ 152.99	$ 144.16	$ 142.96	$ 47.90	$ 48.93	$ 52.72	$ 81.40
2022	$ 53.90	$ 53.47	$ 50.49	$ 48.85	$ 49.09	$ 140.12	$ 156.78	$ 151.93	$ 144.10	$ 48.84	$ 52.15	$ 55.52	$ 83.77
2023	$ 55.87	$ 56.58	$ 52.50	$ 49.36	$ 52.16	$ 145.43	$ 160.46	$ 156.28	$ 148.10	$ 49.46	$ 54.70	$ 57.03	$ 86.49
2024	$ 61.18	$ 57.42	$ 54.21	$ 52.02	$ 51.84	$ 148.97	$ 165.04	$ 161.27	$ 152.42	$ 55.66	$ 57.34	$ 58.53	$ 89.66
2025	$ 62.15	$ 61.74	$ 57.60	$ 54.58	$ 53.40	$ 148.55	$ 165.94	$ 163.46	$ 152.05	$ 55.87	$ 58.54	$ 61.07	$ 91.25
2026	$ 65.24	$ 64.64	$ 60.26	$ 57.85	$ 55.87	$ 153.86	$ 170.97	$ 164.11	$ 156.99	$ 57.94	$ 60.78	$ 63.87	$ 94.37
2027	$ 66.80	$ 66.82	$ 61.65	$ 59.04	$ 56.53	$ 155.55	$ 174.64	$ 164.11	$ 159.25	$ 59.88	$ 61.97	$ 64.82	$ 95.92
2028	$ 68.01	$ 68.82	$ 62.01	$ 59.01	$ 58.53	$ 161.21	$ 178.14	$ 173.77	$ 163.05	$ 58.70	$ 64.41	$ 66.82	$ 98.54
2029	$ 69.93	$ 70.48	$ 64.47	$ 62.07	$ 61.27	$ 165.43	$ 182.03	$ 180.10	$ 167.79	$ 63.75	$ 67.39	$ 68.82	$ 101.96
2030	$ 72.34	$ 71.98	$ 66.98	$ 64.48	$ 63.60	$ 167.64	$ 184.36	$ 181.61	$ 170.51	$ 69.12	$ 69.41	$ 71.50	$ 104.46
2031	$ 73.74	$ 73.21	$ 67.68	$ 66.10	$ 65.13	$ 170.81	$ 191.29	$ 183.87	$ 172.26	$ 68.14	$ 71.37	$ 73.97	$ 106.46
2032	$ 76.46	$ 72.91	$ 72.56	$ 70.37	$ 67.57	$ 181.15	$ 200.39	$ 186.53	$ 182.54	$ 70.94	$ 74.60	$ 77.31	$ 111.11
2033	$ 76.79	$ 79.90	$ 73.59	$ 71.94	$ 68.34	$ 184.61	$ 203.54	$ 195.02	$ 185.86	$ 73.80	$ 77.29	$ 80.38	$ 114.26
2034	$ 82.17	$ 84.40	$ 78.67	$ 75.90	$ 78.19	$ 192.98	$ 210.29	$ 206.32	$ 194.99	$ 77.58	$ 83.70	$ 86.09	$ 120.94
2035	$ 90.96	$ 90.07	$ 85.98	$ 82.59	$ 84.22	$ 200.68	$ 216.11	$ 215.16	$ 202.82	$ 86.35	$ 89.83	$ 92.11	$ 128.07
2036	$ 97.44	$ 95.34	$ 90.45	$ 90.85	$ 87.95	$ 202.58	$ 225.58	$ 219.68	$ 209.07	$ 92.66	$ 96.31	$ 98.59	$ 133.88
2037	$ 100.92	$ 98.95	$ 93.66	$ 94.63	$ 91.40	$ 208.16	$ 233.43	$ 225.63	$ 213.54	$ 96.74	$ 98.95	$ 102.29	$ 138.19
2038	$ 104.78	$ 103.05	$ 98.49	$ 99.10	$ 96.54	$ 214.35	$ 239.38	$ 232.28	$ 220.84	$ 99.06	$ 103.67	$ 107.49	$ 143.25
2039	$ 109.23	$ 107.42	$ 102.17	$ 102.28	$ 98.91	$ 215.24	$ 237.12	$ 235.71	$ 222.87	$ 103.62	$ 107.93	$ 113.87	$ 146.36
2040	$ 112.87	$ 111.96	$ 105.63	$ 107.16	$ 103.26	$ 222.60	$ 243.76	$ 241.39	$ 229.06	$ 109.28	$ 114.48	$ 116.06	$ 151.46
2041	$ 118.46	$ 116.22	$ 111.13	$ 112.17	$ 107.80	$ 229.27	$ 249.57	$ 244.93	$ 235.71	$ 113.54	$ 118.51	$ 121.38	$ 156.56
2042	$ 123.13	$ 120.57	$ 114.51	$ 117.57	$ 115.83	$ 233.60	$ 257.01	$ 252.43	$ 244.33	$ 118.23	$ 122.47	$ 126.65	$ 162.19

Limits on Availability of Long-Term Avoided Cost Rate

Nevada Power proposes that the availability of long-term avoided cost rates be limited to a maximum of 25 MW of QF contracts.

Methodology to Derive Avoided Costs Payments

Nevada Power believes that the above long-term avoided cost rates should act as a cap on the actual payments under a long term QF contract. The actual contract payment is derived from a competitive bidding solicitation process with the winning bidders receiving payments at a rate equal to or less than the above rates as determined by the most competitive proposals.

SECTION 4. FINANCIAL PLAN

A. INTRODUCTION

The following section summarizes the results of the analysis of financial impacts of the Preferred Plan (Case 2:5-7EAS 2018) and the Alternate Plan (Case 3: 275 MW Tolling). The Financial Plan spans a 20-year period (2013-2032) and analyzes these two scenarios from the perspective of several customer and company financial impacts as mandated by NAC §704.9401(1). Also included in the Financial Plan is a description of the financial forecasting assumptions and common methodologies used to prepare the financial plan.

The Preferred Plan assumes the construction of 375 MW of new peaking generation in 2018. Both the Preferred and Alternate cases contemplate the completion of the ON Line at the revised budget of $552.1 million, with a revised in service date of December 31, 2013. Both the Preferred and Alternate cases assume a payment of $42.7 million to the California Department of Water Resources ("CDWR") in 2013. This payment represents the final payment due to CDWR under the Participation Agreement.

B. CAPITAL EXPENDITURES

The capital expenditures and cash flow analysis prepared for the Financial Plan utilize the CER model for the Preferred and Alternative Plan. Figure FP-1 below compares total capital expenditures (excluding AFUDC) for both plans on a yearly basis over the forecast horizon. Figure FP-2 shows generation and transmission projects start and end dates as reflected in the CER.

Please note that while the CER model (and thus the Financial Plan) for the Preferred Plan shows some investment during the Action Plan period (January 2013 through December 2015) to permitting and siting of 345 MW of peaking capacity in 2018 , Nevada Power is not seeking authority to proceed with the construction at this time. Instead, Nevada Power is seeking authority to expend only those dollars necessary to identify, secure and begin permitting a new Greenfield and/or Brownfield site. The Company will return to the Commission requesting authority to proceed with additional capital investment associated with a distinct project in a future resource plan or resource plan amendment.

FIGURE FP-1 - CAPITAL EXPENDITURES ($000)
(Without afudc)

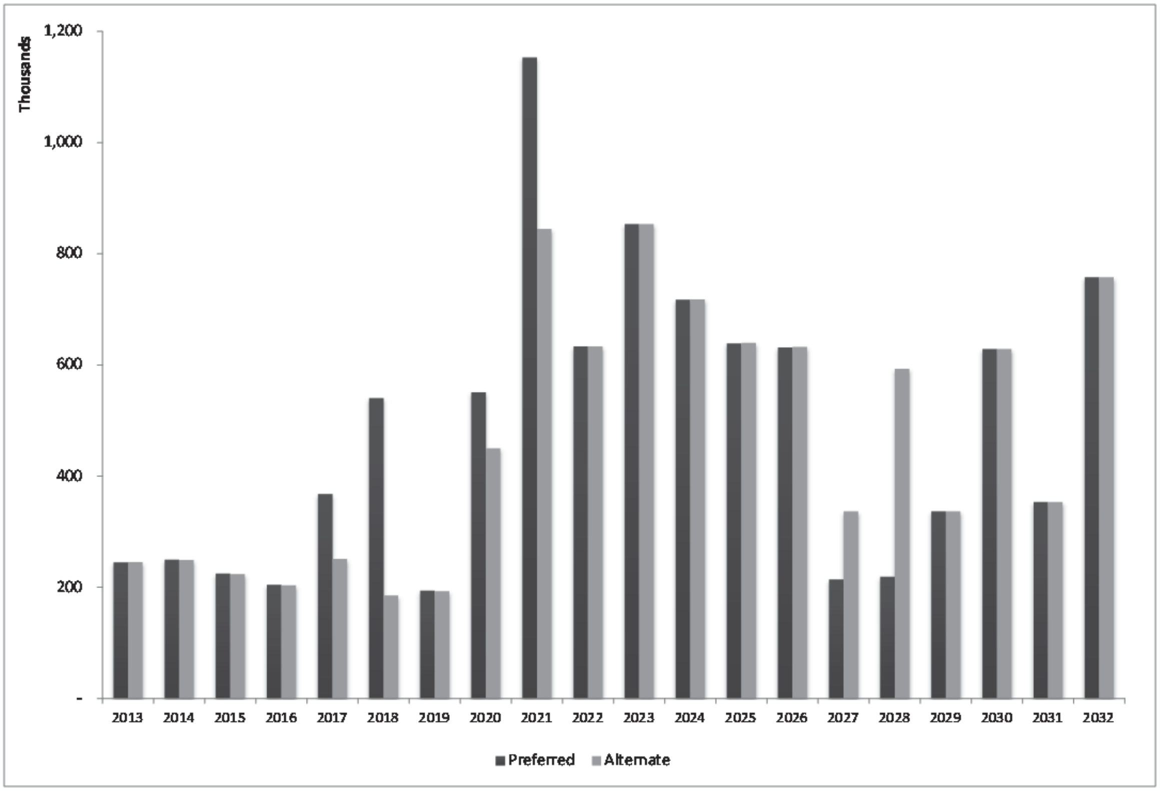


FIGURE FP-2 - PROJECT SCHEDULES

Project Name	Start Date	Completion Date
Generation Projects		
RG4 Payment	2013	2013
375 MW 7EA	2014	2018
225 MW 7EA	2017	2021
450 MW 7EA	2017	2021
237 MW CC	2017	2022
225 MW 7EA	2019	2023
576 MW CC	2019	2024
576 MW CC	2021	2026
181 MW (3) LMS	2026	2030
181 MW (3) LMS	2028	2032
237 MW CC	2029	2034
576 MW CC	2030	2035
181 MW (3) LMS	2032	2036
Transmission Projects		
E Nevada Microwave	2007	2013
ON Line	2006	2013
Transmission Upgrade RG123	2018	2021

C. EXTERNAL FINANCING REQUIREMENTS (REDACTED)

Cash generated from internal operations is insufficient to cover the capital expenditures required by both plans analyzed. In order to meet funding requirements, maintain coverage ratios, target capital structure and preserve investment grade credit metrics, external financing is required. External financing requirements (including expenditures for normal operations and previously approved projects) total [redacted] (Preferred Plan, Case 2), and [redacted] (Alternate Plan, Case 3). Figures FP-3(A) and FP-3(B) below show the annual total debt and equity financing per plan over the forecast horizon.

FIGURE FP-3(A) – (REDACTED) SUMMARY OF EXTERNAL FINANCING PREFERRED PLAN ($000)

[redacted]

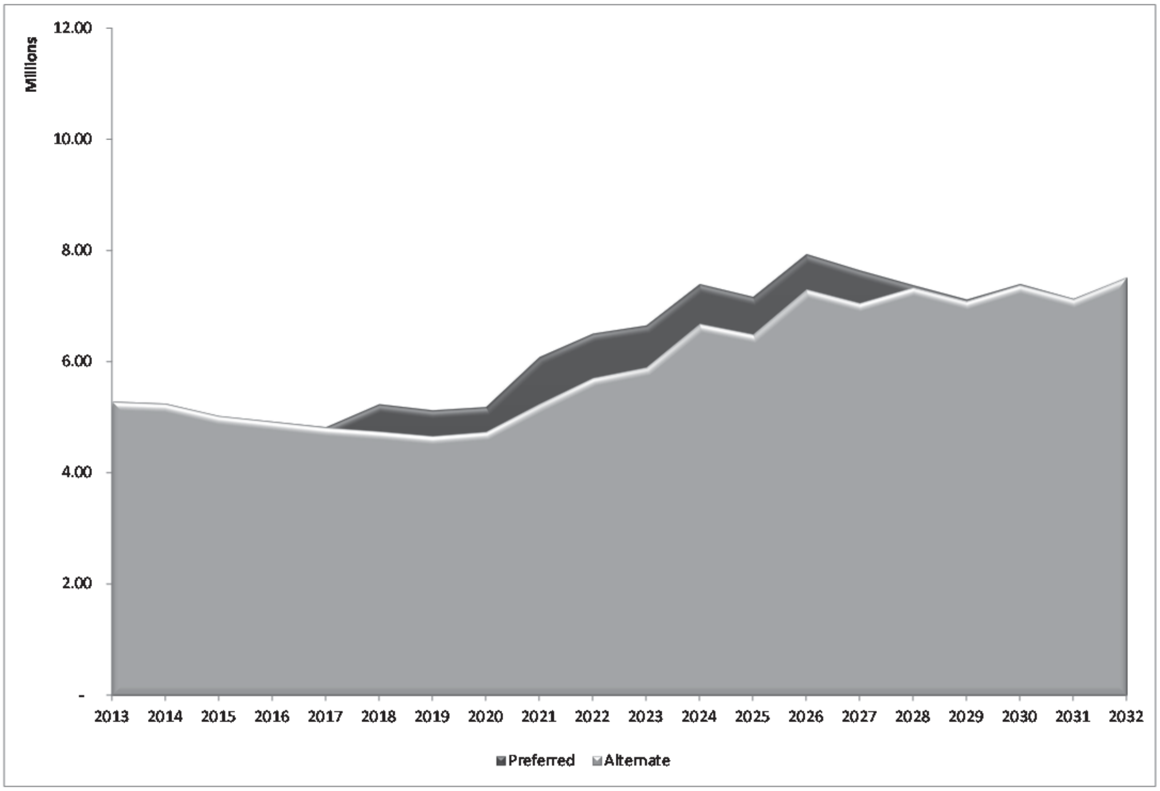
FIGURE FP-3(B) -(REDACTED) SUMMARY OF EXTERNAL FINANCING

[redacted]

D. TOTAL RATE BASE

Figure FP-4 below compares total rate base per year over the forecast horizon. Compound annual growth rates for rate base over the forecasted horizon total 1.87% for the Preferred Plan, and 1.88% for the Alternate Plan. Figure FP-4 below also shows the total annual electric rate base for Nevada Power over the forecast horizon.

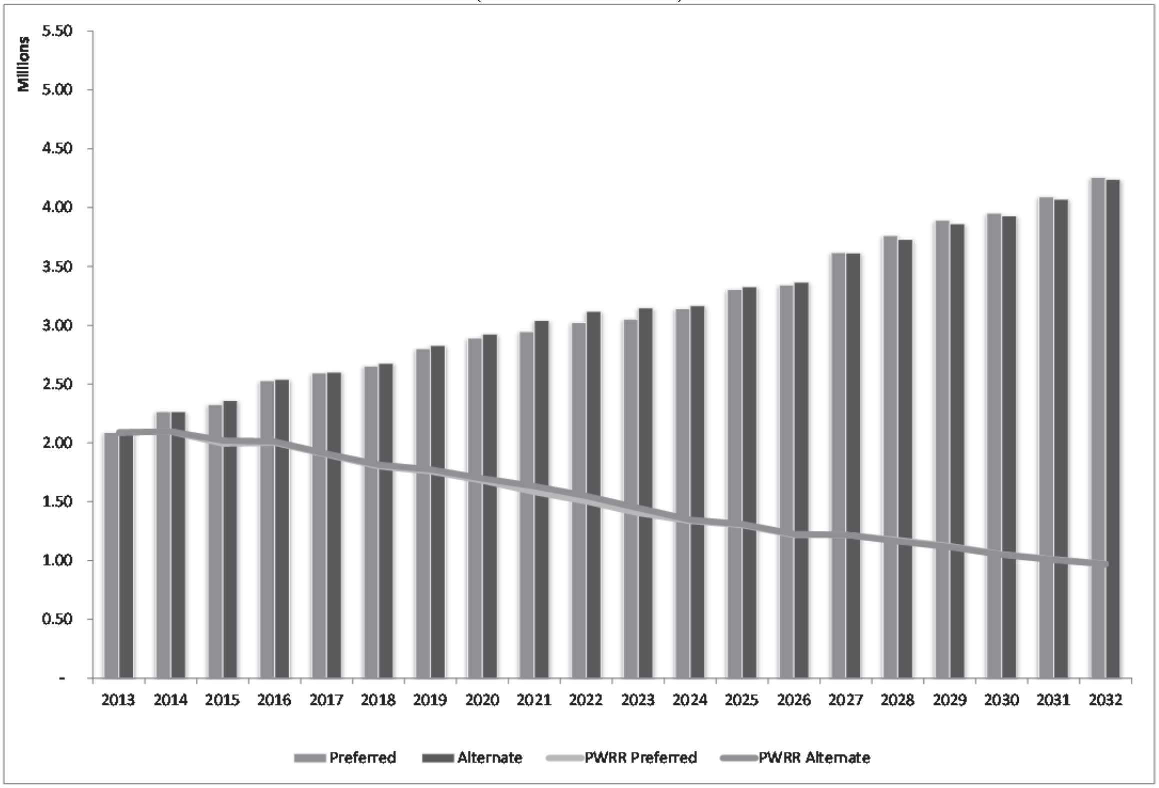
FIGURE FP-4 - ELECTRIC COMPANY RATE BASE ($000)



E. ELECTRIC REVENUE REQUIREMENT

The model used in this 2012 IRP continues to reflect separate revenue requirements for the Southern (Nevada Power) and Northern (Sierra) service territories following the completion of the ON Line. During the 20-year forecast period, the Preferred Plan results in an increase in electric revenue requirements at Nevada Power of 3.8% annually (from approximately $2.1 billion to $4.3 billion), and/or 3.8% annually under the Alternate Plan ($2.1 billion to $4.2 billion). Figure FP-5 shows estimated annual total electric revenue requirements (in nominal and real dollars) for Nevada Power for the forecast period as well as its value as measured in PWRR.

FIGURE FP-5 - TOTAL ELECTRIC REVENUES AND PRESENT WORTH
(THOUSANDS)



F. COMMON METHODOLOGIES / ASSUMPTIONS

The following section discusses the common methodologies and assumptions used in forecasting and evaluating the financial impact of the 2012 IRP.

1. COMMON METHODOLOGIES

The financial analysis was performed using the Company's financial forecasting model, a Microsoft Excel based spreadsheet. The model uses many of the same inputs (capital expenditures or "CAPEX", AFUDC rate based at the Company's authorized rates of return, production costs, depreciation rates and load forecast) from the CERs that are utilized in the economic analysis described earlier. Additional inputs include a proforma capital structure and estimated cost of debt.

The financial analysis includes the annual cash flows and capital expenditures associated with the construction of the ON Line, as well as the combustion turbines scheduled to be completed in 2018 and 2021.

2. ASSUMPTIONS

Major financial modeling assumptions are described below. Unless noted, assumptions are the same for the entire forecast period.

- Nevada Power's next general rate increase will go into effect January 1, 2015.[47]
- Inflation Rates (GDP deflator) over the forecast horizon average 2.0%.
- The AFUDC rate for new projects is set at the marginal cost of capital 8.08%.
- The marginal weighted average cost of capital of 8.08% was used as the discount rate, and was based on the currently authorized 10.0% return on equity ("ROE") with a proforma capital structure of 45% equity, 55% debt.
- The assumed marginal cost of new debt is 6.50% based on current pricing information.
- A 35.00% effective income tax rate.
- Revenue requirements are based on currently authorized 10.0% ROE.[48]
- 100 percent recovery of all costs incurred (including energy, operating and capital).

Escalation rates were obtained from the Company's 2012 Planning Guidelines document published by the Finance organization. See, Figure FP-6. For the years beyond the end of the table, the escalation rates were extrapolated. Capital costs (excluding the RG4 payment) were escalated based upon the Common Construction Escalation Rates. All other escalations utilize the GDP deflator. The source material from which the Planning Guidelines were prepared was provided by IHS Global Insight.

[47] The 2009 Legislature modified the schedule pursuant to which general rate cases will be filed and rate changes will go into effect. Under the new schedule, AB510 Section 4 – NRS 704.110, Nevada Power must file a general rate case no later than June 1, 2014. Rates set pursuant to this filing must go into effect by January 1, 2015.

[48] The results of the Order in Docket No. 11-06006.

FIGURE FP-6 - ESCALATION RATES USED IN PWRR ANALYSIS

YEAR	GDP Deflator (%)		Construction Escalation Rates - Common (%)
2007	2.9	2010	3.74
2008	2.2	2011	3.36
2009	1.08	2012	2.56
2010	1.16	2013	2.79
2011	1.99	2014	3.34
2012	0.96	2015	3.24
2013	1.44	2016	2.7
2014	1.86	2017	2.6
2015	1.89	2018	2.56
2016	1.87	2019	2.56
2017	1.82	2020	2.57
2018	1.75	2021	2.67
2019	1.67		
2020	1.65		
2021	1.63		
2022	1.67		
2023	1.67		
2024	1.67		
2025	1.68		
2026	1.72		
2027	1.72		
2028	1.73		
2029	1.76		
2030	1.78		
2031	1.82		
2032	1.81		

Figure FP-7 illustrates Nevada Power's marginal cost of capital using the proforma capital structure of 45% equity, 55% debt.

FIGURE FP-7 - PROFORMA MARGINAL WEIGHTED AVERAGE COST OF CAPITAL

Capital Class	Ratio (Weight)	Rate (k)	Weighted Average Rate
Debt	55.00%	6.50%	3.58%
Equity	45.00%	10.00%	4.50%
Total	100.00%		8.08%

G. RISK MANAGEMENT STRATEGY

Nevada Power's risk management strategy is presented in Section VII of the Energy Supply Plan ("ESP") for 2013-2015, which is being filed separately with this 2012 IRP. The risk management strategy is structured to mitigate risk in the following respects:

Evaluation of Options. Risk minimization activities start with the planning process and the decisions for demand or supply options that are examined and eventually integrated into the Company's Integrated Resource Plan and ESP. Starting with the load forecast, the Company establishes customers' needs, including appropriate reserve margins. Once those needs are known, it then assesses the options available to meet those needs. A part of that process is an examination of market fundamentals in the region, including the outlook for change over the planning horizon.

Reduce Reliance on Volatile Wholesale Energy Markets. The Company's longer term risk management strategy has included increasing the level of Company-owned generation and longer term contracts to reduce exposure to volatility to the capacity portion (scarcity premiums) of the Company's energy supply costs. The Company has reduced its open position, and therefore its exposure, for the 2013-2015 ESP period.

Use of Competitive Procurement Processes. While the Company has reduced its open position, it will be issuing RFPs as warranted to cover the remaining needs through a competitive costs bid process. As part of the risk management plan, an economic analysis of the bid responses will be conducted and the selected options will be referred to the Procurement Department for negotiation and contracting as appropriate.

Implement a Gas Hedging Strategy. The gas hedging strategy proposed in the Energy Supply Plan volume, Section 5.C., is designed to protect ratepayers from extreme price spikes while retaining some ability to follow the market should prices decline.

The Financial Plan assumes implementation of the risk management strategy.

H. FINANCIAL RISKS

This section discusses in more detail several financial matters which are important in assessing the Preferred and Alternative Plan.

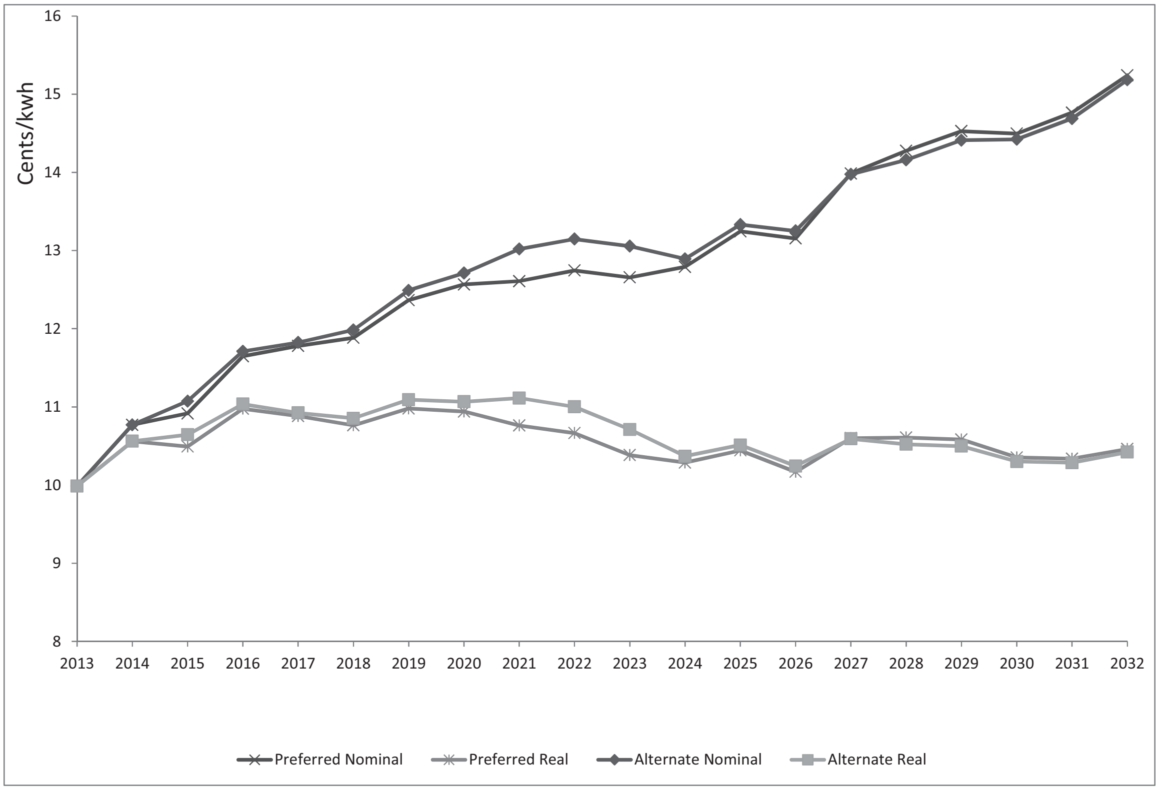
1. EXTERNAL FINANCING COSTS

Due to the gap between capital expenditures and internally generated cash, the Company continues to rely on access to the financial markets. Increasing volatility in, and over-reliance on, financial markets could lead to excessive financing costs for customers in order to fund future investments on their behalf.

2. IMPACT ON AVERAGE SYSTEM COST

As shown in the Figure FP-8, the nominal average system cost per kWh under this Financial Plan increases from 9.99 cents in 2013 to 15.24 cents in 2032 under the Preferred Plan, and 9.99 cents to 15.18 cents under the Alternative Plan. The annual compound system cost increases over the forecast period by 2.25% and 2.23% respectively. The result is an increasing average system cost per kWh as shown below.

FIGURE FP-8 - NOMINAL AVERAGE SYSTEM COST (CENTS/KWH)



3. CREDIT QUALITY

Nevada Power's secured credit is now rated investment grade quality by all three credit rating agencies that rate Nevada Power's credit. Over the last five years, Nevada Power has increased its liquidity and demonstrated access to the debt markets at lower rates. Figures FP-9 and FP-12 show the annual projected credit metrics for Nevada Power for the forecast period.

FIGURE FP-9 - (REDACTED) FUNDS FROM OPERATIONS TO TOTAL DEBT (%)

S&P's average for "BBB" rating is 20 percent for utilities. This S&P ratio measures cash funds from operations as a ratio to total Company debt.

FIGURE FP-10 - (REDACTED) EBITDA INTEREST COVERAGE

S&P's average interest coverage metric for a "BBB" rating is 4.3x for utilities. This S&P ratio measures EBITDA as a multiple of interest obligations. As demonstrated on Figure FP-10 above, performance on the EBITDA metric varies between plans.

FIGURE FP-11 - (REDACTED) TOTAL DEBT TO TOTAL CAPITAL (%)

[redacted]

S&P's target for "BBB" rating is 57 percent for utilities. This S&P Ratio measures the Company's debt to total capital. As shown in Figure FP-11 above, Nevada Power is within the "BBB" range for both cases analyzed.

FIGURE FP-12 - CASH FROM OPERATIONS TO CAPITAL EXPENDITURES

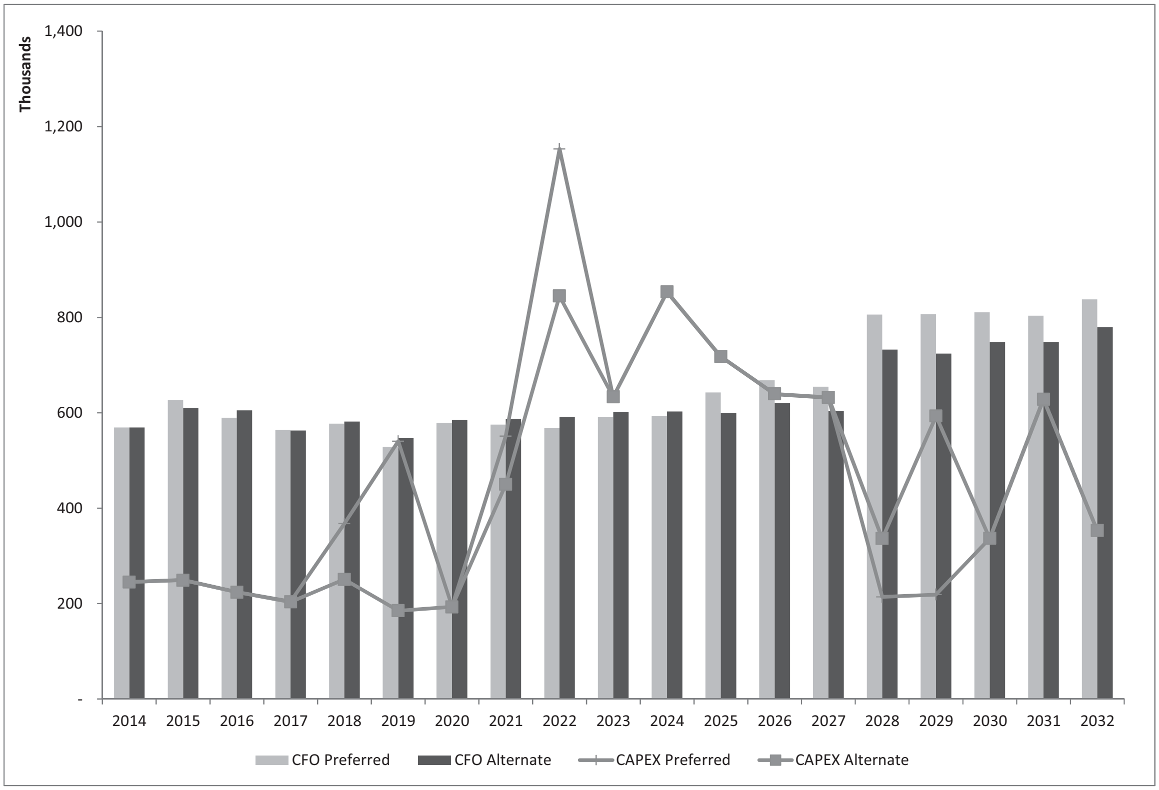


Figure FP-12 above shows cash generated from operations versus capital expenditures over the forecast horizon for both cases analyzed. The difference between cash generated from operations and capital expenditures is to be funded with external capital.

4. DSM RATE IMPACT

In Docket Nos. 11-07026 and 11-07027 the Commission directed Nevada Power to provide a preferred plan and two alternative plans with specific load objectives. In accordance with the Commission's orders Nevada Power has prepared DSM plans with base (DSM Preferred Plan), high (DSM Maximum Net Benefits Alternative Plan) and low (DSM Minimum Impact Alternative Plan) levels of DSM. These plans are described in the DSM volume of the filing and in Mr. Holmes's testimony. The impact of the changes in DSM levels on the load forecast is described in the Load Forecast and Market Fundamentals volume and in Mr. Baxter's testimony. Production costs were then calculated for the Preferred Plan with high and low levels of DSM. The impact on rates has been calculated for the Preferred Plan using the budgets, savings and lost revenue estimates coming from the DSM Preferred Plan scenarios based on the level of capital expenditures required for each scenario. The nominal average system cost impacts can be seen in Technical Appendix FIN-1.

5. GHG COSTS

The Financial Plan assumes that Nevada Power will recover 100 percent of all costs incurred to comply with future legislation regulating carbon emissions through the deferred energy mechanism. Effects of this can be further reviewed using the charts provided in Technical Appendix Item FIN-2. At this time, Nevada Power cannot quantify any additional liquidity requirements associated with carbon legislation.

I. SENSITIVITY ANALYSES

Sensitivity analyses were performed on the Preferred Plan's rate of inflation and cost of external financing (long-term debt). The respective rates were adjusted plus/minus 150 basis points to reflect the variability in forecasting future rates. Under the scenario of increased inflation and interest rates, the PWRR increased $136.6 million or 0.5%. Under the scenario of decreased inflation and interest rates, the PWRR decreased $134.5 million or 0.5%.

J. CONCLUSION

The Company has the financial capacity to finance both the Preferred Plan and the Alternate Plan, as modeled in the Financial Plan and as specified in the Action Plan. However, investments on behalf of the customers exceed cash generated from internal operations, which creates continued reliance on financial markets.