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December 5, 2007

Mr. Douglas Thompson
Manager, Climate Change Reporting
California Air Resources Board
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Sacramento, CA 95812
E-Mail: dthompso@arb.ca.gov

Re: Comments of Sierra Pacific Power Company on CARB Mandatory Reporting and Tracking "45-Day" Draft Regulation

Dear Mr. Thompson:

On behalf of Sierra Pacific Power Company, the following are comments to the "Staff Report: Initial Statement Of Reasons For Rulemaking - Proposed Regulation For Mandatory Reporting Of Greenhouse Gas Emissions Pursuant To The California Global Warming Solutions Act Of 2006 (Assembly Bill 32)". We are also submitting this document electronically to http://www.arb.ca.gov/lispub/comm/bclist.php in accordance with public hearing Notice.

Respectfully submitted,

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COMMENTS OF SIERRA PACIFIC POWER COMPANY ON

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR RULEMAKING - PROPOSED REGULATION FOR MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS PURSUANT TO THE CALIFORNIA GLOBAL WARMING SOLUTIONS ACT OF 2006 (ASSEMBLY BILL 32)

Sierra Pacific Power Company ("SPPC" or "Sierra") respectfully provides these comments on the "Staff Report: Initial Statement Of Reasons For Rulemaking - Proposed Regulation For Mandatory Reporting Of Greenhouse Gas Emissions Pursuant To The California Global Warming Solutions Act of 2006 (Assembly Bill 32)" ("Proposed Regulation"). Sierra presents three concerns for the consideration by the California Air Resources Board ("ARB" or "Board"):

- First, under ARB's proposed regulation, it has chosen NOT to accept a Retail Seller's CARROT report to The California Climate Action Registry ("CCAR"), or as the case may be The Registry, as SPPC expected pursuant to Health & Safety ("H&S") Code section 38530. SPPC's concern is that ARB's regulation could conflict with a new Nevada law and proposed regulation requiring Sierra to report its greenhouse gas ("GHG") emissions to CCAR, potentially leading to jurisdictional conflicts with the State of Nevada.
- Second, there is confusion over how the regulation would apply to SPPC, most principally given Sierra's interstate, integrated utility system. We enumerate several of our concerns below.
- Third, under the proposed regulation, SPPC is required to report on 100% of its Nevada operations even though only 6% of its power is used by California customers. This reporting obligation is potentially burdensome. Furthermore, the proposed regulation

lacks flexibility to count emissions in proportion to carbon-free or low carbon energy destined for California customers or permit SPPC to reduce its reporting obligations should it reduce its carbon footprint in California.

I. BACKGROUND ON SPPC'S UTILITY OPERATIONS.

SPPC is a Nevada corporation providing electric utility services in three jurisdictions: Nevada, California, and the FERC. Sierra operates a single, integrated electrical system with a combined count of over 400,000 customers in both states. Approximately 46,000 SPPC customers reside in California, mostly around Lake Tahoe. Sierra's system summer peak load is about 1,700 MW, 77 MW of which is in California. The California customers represent about 6% of Sierra's total retail system energy sales. In addition, Sierra operates its own control area consistent with Western Electricity Coordinating Council ("WECC") and the North American Electric Reliability Council ("NERC") protocols, and its operations are outside of the control area of the California Independent System Operator ("Cal-ISO").

Except for a small contract for renewable energy from a Qualifying Facility ("QF") in California, and emergency back-up peakers located in Kings Beach, California, all of the capacity and energy used to supply California customers (and its system as a whole) are procured from electric generating facilities ("EGFs") located outside of California. In addition, Sierra currently procures significant quantities of capacity and energy from specified and unspecified sources in other states beyond California, though the proportion of purchased power is likely to diminish in the years to come. Accordingly, Sierra must "import" virtually all of the resources used to serve California load.

II. THERE IS A POTENTIAL CONFLICT AND INCONSISTENCY WITH REPORTING TO NEVADA

Under ARB's proposed section 95111, title 17, California Code of Regulations (the "Proposed Regulation") it has chosen not to accept a Retail Seller's CARROT report to CCAR as meeting its reporting requirements under Health and Safety Code § 38530. ARB has decided to do this despite AB 32's requirement that

> entities that voluntarily participated in the California Climate Action Registry prior to December 31, 2006, and have developed a greenhouse gas reporting program, shall not be required to significantly alter their reporting or verification program except as necessary to ensure that reporting is complete and verifiable for the purposes of compliance with this division as determined by the state board.

(H&S Code § 38530(b)(3).) ARB has made no finding that an alternative, non-CCAR, reporting program is necessary to ensure that Sierra's reporting is complete and verifiable for the purposes of accounting for GHG emissions from all electricity consumed in California. (H&S Code § 38530(b)(2) and (b)(3).)

SPPC voluntarily joined CCAR and made its initial report to CCAR in 2007, in reliance upon assurances placed in the statute that it would not be required to significantly alter its reporting and verification program to CCAR. SPPC's initial concern is that ARB's reporting regulation may conflict with or duplicate the voluntary reporting requirements presently in effect through CCAR. However, irrespective of whether the ARB has made the necessary finding that rejection of CCAR reports is necessary to ensure Sierra's reporting is complete and verifiable, Sierra is also concerned that duplicative reporting would be an additional expense that would impose a needless and unreasonably burdensome cost on its California customers.

In addition, SPPC is now under new mandatory reporting obligations for GHG emissions in Nevada. Pursuant to Nevada Senate Bill ("NSB") 422, Sierra shall be required to report annually the GHG emissions from all electric generating units of five MWs or more to a registry to account for verified GHG emissions on an on-going basis. (NSB 422, section 5; attached as Exhibit A) The Nevada State Environmental Commission ("NSEC") has proposed regulation R. 142-07 implementing this requirement. Proposed R. 142-07 would require the owner or operator of an affected electric generating unit to report its GHG emissions to CCAR on an annual basis, beginning with calendar year 2008 data, pursuant to CCAR protocols and procedures. (Attached as Exhibit B) NSEC was slated to approve R. 142-07 on December 4, 2007. (*See* NSEC Meeting Agenda, 12/04/2007, attached as Exhibit C. *See also* http://www.sec.nv.gov/main/hearing_120407.htm.) However, the NSCE postponed a decision on the matter because it determined that insufficient notice was provided to some power generators of the proposed regulation. The NSEC is expected to take up the matter again at its next meeting, scheduled for some time in March.

Similarly, pursuant to the Proposed Regulation, SPPC will be obligated to begin reporting on its 2008 GHG emissions from the generation of all electricity consumed by its California customers. The California requirement applies to all EGFs with a capacity of 1 MW or more that emit at least 2,500 metric tonnes of CO_2. ARB also proposes to require Retail Providers to report GHG emissions from all EGFs over which they have operational control, whether inside or outside of California. However, the ARB is not proposing to require reporting of emissions from EGFs located outside of California in which a California Retail Seller, such as SPPC, has an ownership interest but no operational control. If such generation is consumed by California

customers, as is the case for SPPC, then the ARB will presumably acquire such emissions data from secondary sources.

Currently, Sierra serves approximately 1,700 MW of peak system load, which includes about 77 MW, or about 4%, of Sierra's coincident summer peak load in California. Except for 20 MW of QF power in California, all California customers are served from EGFs in Nevada. (*Supplemental Proposal of Sierra Pacific Power Company with Respect to Resource Adequacy Requirements for Small and Multi-Jurisdictional Utilities*; filed Sept. 10, 2007, p. 3 ("IRP Proposal"); attached as Exhibit D.) Most of this generating capacity is internal to Sierra, with a significant portion purchased from third parties. However, with the addition of new generation capacity in June 2008, Sierra plans to supply most of its system from self-owned EGFs located in Nevada. (IRP, at p. 4.) Sierra is doing this in response to direction from its principal energy regulator, the Public Utilities Commission of Nevada ("PUCN").

Thus, beginning in 2009, Sierra will have dual GHG emissions reporting obligations to the states of Nevada and California over electricity used to serve California customers. By that time it will supply most of its system load through owned EGFs located in Nevada. It will be required to report all of these sources to the NSEC pursuant to NSB 422; and coincidentally report on all of the same sources, over which it has operational control, to the ARB. The reporting of emissions of the former will be accomplished through CCAR reporting protocols, and for the latter through the Proposed Regulation. The only apparent difference in the scope of the reporting obligations is that under NSB 422, there is a de minimis reporting threshold for units of 5 MWs or more; whereas under the Proposed Regulation the threshold is only 1 MW.

However, Sierra plans to submit a complete inventory of its GHG emissions pursuant to CCAR protocols, irrespective of the 5 MW threshold. Indeed, in its initial filing to CCAR,

covering 2006 GHG emissions, pursuant to the CARROT protocol, Sierra has inventoried *100 percent* of associated GHG emissions from operations and facilities that are wholly owned, and *all emissions* from partially owned operations according to its equity share. This approach is in compliance with the recommendations of CCAR. Thus, the only GHG emissions excluded from Sierra's 2006 GHG emissions inventory were estimates of methane and nitrogen dioxide emissions and emissions from fleet vehicles, sources not currently required under the Proposed Regulation. These emissions are estimated to represent less than 0.5% of Sierra's total CO_2 equivalent emissions. Thus, CCAR's CARROT protocols are complete (and verifiable) and potentially even more complete than the Proposed Regulation since it will include all GHG emissions from resources used to serve California customers, regardless of Sierra's operational control.

Because of these concurrent GHG emissions reporting obligations, and the location of Sierra's resources, it will soon be reporting its Nevada-based GHG emissions to both the PUCN and the ARB. Though the scope of the reporting obligation is essentially duplicative, the emissions inventories reported to the two states are potentially different because the reporting protocols will be different. Sierra is concerned that different reporting protocols could result in different inventories of the same actual GHG emissions. This situation obviously could lead to confusion and could challenge the integrity of Sierra's inventory, cap and allowance allocation in any prospective California cap-and-trade scheme or regional cap-and-trade system. Moreover, ARB's Proposed Regulation would place an arm of the State of California in the position of calculating a potentially different inventory of GHG emissions from electric power generation in Nevada from that calculated by an agency of the Nevada state government. At best, this presents a potentially awkward situation; at worse, it presents a source of friction with the State of

Nevada. Additionally, there exists at present a sensitivity in neighboring states to the broad, and potentially extraterritorial, reach of California legislation outside its boarders, particularly with respect to this issue. The current draft of ARB's reporting regulation could potentially exacerbate the situation.

A simple and practicable way for the ARB to avoid these complications would be to accept the mandatory reports on GHG emissions that Sierra will submit to the NSEC. This approach would be both reliable and defensible from ARB's perspective. Since Sierra's reports will be mandated under Nevada law, ARB is assured that the data will be prepared subject to regulatory oversight. Also, since Sierra will follow CCAR protocols, which ARB is actually *required* to accept in the absence of a finding that the protocols are incomplete or unverifiable, which they are not, the California Legislature has mandated the use of this reporting method for Sierra's compliance with AB 32. In short, ARB can acquire all the information it needs to calculate California's *pro rata* share of Sierra's GHG emissions through SPPC reporting to the NSEC through CCAR but with much less effort and cost than under the Proposed Regulation.

A model for such an approach can be found in the CPUC's D.07-01-039 ("*Interim Decision on Phase 1 Issues: Greenhouse Gas Emissions Performance Standard*", January 25, 2007), where the CPUC granted to Sierra and PacifiCorp an alternative compliance mechanism conditioned upon obligations to disclose GHG emissions to another state's regulatory commission. A similar rule based upon the additional disclosure requirements of NSB 422 would be consistent with existing CPUC policy and would fulfill the intent of AB 32.

III. THERE IS CONFUSION OVER HOW THE PROPOSED REGULATION WOULD APPLY TO SPPC.

Since Sierra has an integrated electrical system and procures virtually all of its energy from sources outside of California, the proposed regulation would have it report all procurement used to meet California load as *imports* from both specified and unspecified sources. Sierra's unique position as a utility that straddles both jurisdictions creates uncertainty with respect to how to interpret several requirements under proposed section 95111, including:

- How does Sierra comply with 95111(a)(1)(K), which requires reporting of all energy sales from facilities it operates and exports "directly out-of-state"? Sierra has the same question with respect to 95111(a)(2)(D).
- How does Sierra report energy purchased from its California QF to serve both Nevada and California customers in order to comply with Section 95111(b)(2)(D)'s requirement to report "power *exported* from specified sources inside California"? Is this purchase an export because it is used to satisfy Nevada load, even though it also serves California customers? A similar section (§95111(b)(3)(E)) requires SPPC to report the same purchase as "power purchased or taken from an in-state specified source."
- SPPC generates, purchases and sells energy outside California. Does it make sense to label all these sales as "exports" with the exception of wholesale sales to purchasers who inform SPPC that they plan to deliver that energy into California? (95111(b)(3)(I).)

These are confusing requirements that would only muddle SPPC's reporting. The ARB has not adequately explained why these rules are necessary departures from CCAR's protocols,

which require simple reporting of GHG emissions sources. Sierra believes that these and other requirements aimed at estimating imported power result in more uncertainty and less precision in calculating Sierra's GHG emissions inventory in Nevada. A simplified approach that would avoid these issues would be to defer to the reporting requirements of NSB 422 and prospective R. 142-07, and accept the GHG emissions inventory for Sierra's overall system reported via CCAR protocols. The ARB could then apply an appropriate *pro rata* allocation of emissions to determine California's share.

IV. THE PROPOSED REGULATION'S REPORTING REQUIREMENTS ARE BURDENSOME AND LACK FLEXIBILITY.

Under the Proposed Regulation, SPPC is required to report on all of its Nevada operations, including facilities it operates and all energy transactions occurring outside of California, because a small percentage of its total system load is in California. It appears that ARB will use this ratio of California sales to system sales to apportion Sierra's "California" emissions from an inventory of total system emissions. (*See* § 95111(b)(3)(C).)

SPPC is concerned that a fixed apportionment based on retail load is not flexible enough to allocate GHG emissions to California load under the likely scenario of a cap-and-trade system with emissions allocated to load. For example, Sierra has a renewables portfolio standard ("RPS") obligation in California that differs temporally from its RPS obligation in Nevada. The respective state RPS obligations operate under different timetables. To comply with its California obligation Sierra has two choices: either accelerate procurement of renewable energy across its entire system so the California piece can also meet the California RPS, or accelerate the California territory only. However, Sierra has one, integrated system and only one control area for both states. Thus, it cannot dispatch renewable energy solely for California. Thus, the

only way that Sierra can meet California's accelerated RPS schedule for California alone is to allocate a portion of its renewable procurement to California on a different basis than pro rata, retail sales. Indeed, Sierra has submitted its plan to the CPUC to procure a new renewable energy facility and dedicate a portion of that power especially for California.

Under the regulation as proposed, Sierra would not be able to perform a similar allocation with respect to a facility with lower GHG emissions than its system average in order to meet a California cap. The current scheme would not allow Sierra to procure carbon-free energy for California because it fixes an allocation of Sierra's system-wide carbon emissions using a single formula of the ratio of California retail sales to total system sales. Consequently, the only avenues open to Sierra for reducing its pro rata share of "California" emissions would be either 1) to reduce GHG emissions for Sierra's system as a whole (virtually all of which occur in Nevada and 94 percent of which are due to Nevada load); or 2) to procure allowances to reduce its "California" inventory to meet the California cap. Sierra contends that the former approach unreasonably interferes with existing law and regulation of Sierra's Nevada operations. Sierra also believes that the latter approach would place its California ratepayers at a disadvantage since they could not take full advantage of a cap-and-trade scheme, as their *only* method of compliance would be to purchase allowances.

Additionally, even if SPPC were inclined to follow California law over Nevada law and reduce its GHG emissions for its system as a whole, it might not be allowed to do so by the PUCN, nor is it likely that the PUCN would allocate the costs to Nevada ratepayers for reducing Nevada emissions to meet California requirements. Thus, the only avenue remaining to SPPC would be to assign all costs for reducing GHG emissions across Sierra's system to California ratepayers. Needless to say, such a disproportionate allocation of costs is unlikely to be

permitted by the CPUC.

Consequently, Sierra is requesting that the proposed reporting regulation be amended to provide for greater flexibility than an allocation based upon the proportion of load of California customers relative to Sierra's system as a whole. Such a change would allow Sierra to allocate or earmark specific zero emission renewable or clean energy procurements to California to meet AB 32 requirements along with RPS requirements.

V. CONCLUSION

Sierra's recommended solution to the challenges illustrated above is to defer to the State of Nevada for Sierra's reporting obligation for GHG emissions in Nevada. Under Nevada law, Sierra will be required to report its entire carbon footprint pursuant to the protocols of CCAR/Registry. This source-based reporting will be thorough and reliable and the ARB is otherwise required to accept it pursuant to Health & Safety Code § 38530(b)(3) unless it finds it necessary not to do so. Since ARB agrees that its reporting requirements are functionally the same as CCAR anyway, the data that Sierra reports to the Nevada SEC should be acceptable to ARB. Thus, we request that ARB amend its regulation to accept Sierra's reports to the Nevada SEC.

This has several, obvious advantages to ARB. First, it vastly simplifies reporting requirements for Sierra emissions. Second, it reduces the administrative burden on ARB, the CPUC and CEC to calculate essentially 100 percent imported power. Third, it avoids potential jurisdictional issues concerning the authority of ARB to obtain data from Sierra's Nevada operations. Fourth, it avoids a potential jurisdictional conflict with the PUCN and the Nevada SEC over reporting obligations. Fifth, it would prevent a potentially disproportionate allocation of compliance costs to California ratepayers. Sixth, and most importantly for a potential cap-

and-trade scheme in California (and regionally), it will provide more accurate data on GHG emissions attributable to California load because Sierra would report its own emissions and its reporting would be more complete than under the ARB's proposed regulation. Sierra's Nevada report would be more complete and more easily verifiable than data submitted under ARB's alternative, and thus the data on Sierra's emissions would have more integrity than data compiled pursuant to the proposed regulation.

Respectfully submitted,

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Exhibit A:

Nevada Senate Bill 422

Senate Bill No. 422–Senator Titus

CHAPTER.....

AN ACT relating to pollution; requiring the State Environmental Commission to mandate the reporting of all greenhouse gases emitted by each affected unit in this State for inclusion in a registry of greenhouse gas emissions; requiring the State Department of Conservation and Natural Resources to issue a statewide inventory of greenhouse gases released in this State; providing a penalty; and providing other matters properly relating thereto.

Legislative Counsel's Digest:

Under existing law, the State Environmental Commission may adopt certain regulations to prevent, abate and control air pollution and establish standards for air quality. (NRS 445B.210)

Section 5 of this bill requires the Commission to mandate the reporting of greenhouse gases emitted by certain generators of electricity in this State for inclusion in a registry of greenhouse gas emissions and to establish the requirements for participation in the registry. **Section 4** of this bill defines a "greenhouse gas" to mean carbon dioxide, hydrofluorocarbons, methane, nitrous oxide, perfluorocarbons and sulphur hexafluoride. **Section 5** authorizes the Commission to prescribe the requirements and procedures for reporting the emissions of greenhouse gases that must be included in the registry, methods for determining the greenhouse gases that must be reported and methods for independently verifying the information that is reported. The Commission may establish the reporting period, but the period must not exceed 1 year.

Section 6.5 of this bill requires the State Department of Conservation and Natural Resources to issue, at least every 4 years, a statewide inventory of greenhouse gases released in this State. The inventory must include the origins, types and amounts of the greenhouse gases, together with the Department's analysis of those gases, and must be supported with documentation.

THE PEOPLE OF THE STATE OF NEVADA, REPRESENTED IN SENATE AND ASSEMBLY, DO ENACT AS FOLLOWS:

Section 1. Chapter 445B of NRS is hereby amended by adding thereto the provisions set forth as sections 2 to 6.5, inclusive, of this act.

Sec. 2. (Deleted by amendment.)

Sec. 3. (Deleted by amendment.)

Sec. 4. ***"Greenhouse gas" means any of the following gases, either alone or in combination:***

1. ***Carbon dioxide (CO_2);***
2. ***Hydrofluorocarbons;***
3. ***Methane (CH_4);***
4. ***Nitrous oxide (N_2O);***

5. Perfluorocarbons; and

6. Sulphur hexafluoride (SF_6).

Sec. 5. *1. In addition to any regulation adopted pursuant to NRS 445B.210 to prevent, abate and control air pollution, the Commission shall, by regulation:*

(a) Mandate the reporting of all greenhouse gases emitted by each affected unit in this State for inclusion in a registry of greenhouse gas emissions; and

(b) Except as otherwise provided in subsection 3, establish the requirements for participation in the registry.

2. The regulations may include, without limitation, provisions setting forth:

(a) The requirements and procedures for reporting emissions of greenhouse gases;

(b) Methods for determining the emissions of greenhouse gases that must be reported for inclusion in the registry;

(c) Methods for independently verifying the information reported for inclusion in the registry; and

(d) The reporting period, except that the period must not exceed 1 year.

3. The requirements for participation in the registry established pursuant to paragraph (b) of subsection 1 must not prohibit a person who does not own or operate an affected unit from voluntarily participating in the registry.

4. As used in this section:

(a) "Affected unit" means a unit for the generation of electricity that:

(1) Has a maximum design output capacity of not less than 5 megawatts;

(2) Emits a greenhouse gas; and

(3) Generates electricity for sale.

➥ The term does not include a unit that uses renewable energy, as defined in NRS 704.7811, to generate electricity.

(b) "Registry of greenhouse gas emissions" or "registry" means a repository or ongoing account of verified greenhouse gas emissions.

Sec. 6. (Deleted by amendment.)

Sec. 6.5. *1. The Department shall, not later than December 31, 2008, and at least every 4 years thereafter, issue a statewide inventory of greenhouse gases released in this State.*

2. The inventory must include, without limitation:

(a) The origins, types and amounts of those greenhouse gases;

(b) The Department's analysis of the information set forth in paragraph (a); and

(c) Documentation for the information set forth in paragraphs (a) and (b).

Sec. 7. NRS 445B.105 is hereby amended to read as follows:

445B.105 As used in NRS 445B.100 to 445B.640, inclusive, ***and sections 2 to 6.5, inclusive, of this act,*** unless the context otherwise requires, the words and terms defined in NRS 445B.110 to 445B.155, inclusive, ***and section 4 of this act*** have the meanings ascribed to them in those sections.

Sec. 8. NRS 445B.210 is hereby amended to read as follows:

445B.210 The Commission may:

1. Subject to the provisions of NRS 445B.215, adopt regulations consistent with the general intent and purposes of NRS 445B.100 to 445B.640, inclusive, ***and sections 2 to 6.5, inclusive, of this act*** to prevent, abate and control air pollution.

2. Establish standards for air quality.

3. Require access to records relating to emissions which cause or contribute to air pollution.

4. Cooperate with other governmental agencies, including other states and the Federal Government.

5. Establish such requirements for the control of emissions as may be necessary to prevent, abate or control air pollution.

6. By regulation:

(a) Designate as a hazardous air pollutant any substance which, on or after October 1, 1993, is on the federal list of hazardous air pollutants pursuant to 42 U.S.C. § 7412(b); and

(b) Delete from designation as a hazardous air pollutant any substance which, after October 1, 1993, is deleted from the federal list of hazardous air pollutants pursuant to 42 U.S.C. § 7412(b),

➥ based upon the Commission's determination of the extent to which such a substance presents a risk to the public health.

7. Hold hearings to carry out the provisions of NRS 445B.100 to 445B.640, inclusive, ***and sections 2 to 6.5, inclusive, of this act,*** except as otherwise provided in those sections.

8. Establish fuel standards for both stationary and mobile sources of air contaminants. Fuel standards for mobile sources of air contaminants must be established to achieve air quality standards that protect the health of the residents of the State of Nevada.

9. Require elimination of devices or practices which cannot be reasonably allowed without generation of undue amounts of air contaminants.

Sec. 9. NRS 445B.220 is hereby amended to read as follows:

445B.220 In carrying out the purposes of NRS 445B.100 to 445B.640, inclusive, ***and sections 2 to 6.5, inclusive, of this act,*** the Commission, in addition to any other action which may be necessary or appropriate to carry out ~~[such]~~ ***those*** purposes, may:

1. Cooperate with appropriate federal officers and agencies of the Federal Government, other states, interstate agencies, local governmental agencies and other interested parties in all matters relating to air pollution control in preventing or controlling the pollution of the air in any area.

2. Recommend measures for control of air pollution originating in this State.

Sec. 10. NRS 445B.230 is hereby amended to read as follows:

445B.230 The Department shall:

1. Make such determinations and issue such orders as may be necessary to implement the purposes of NRS 445B.100 to 445B.640, inclusive ~~[.]~~ ***, and sections 2 to 6.5, inclusive, of this act.***

2. Apply for and receive grants or other funds or gifts from public or private agencies.

3. Cooperate and contract with other governmental agencies, including other states and the Federal Government.

4. Conduct investigations, research and technical studies consistent with the general purposes of NRS 445B.100 to 445B.640, inclusive ~~[.]~~ ***, and sections 2 to 6.5, inclusive, of this act.***

5. Prohibit as specifically provided in NRS 445B.300 and 445B.320 and as generally provided in NRS 445B.100 to 445B.640, inclusive, ***and sections 2 to 6.5, inclusive, of this act*** the installation, alteration or establishment of any equipment, device or other article capable of causing air pollution.

6. Require the submission of such preliminary plans and specifications and other information as it deems necessary to process permits.

7. Enter into and inspect at any reasonable time any premises containing an air contaminant source or a source under construction for purposes of ascertaining compliance with NRS 445B.100 to 445B.640, inclusive ~~[.]~~ ***, and sections 2 to 6.5, inclusive, of this act.***

8. Specify the manner in which incinerators may be constructed and operated.

9. Institute proceedings to prevent continued violation of any order issued by the Director and to enforce the provisions of NRS 445B.100 to 445B.640, inclusive ~~[.]~~ ***, and sections 2 to 6.5, inclusive, of this act.***

10. Require access to records relating to emissions which cause or contribute to air pollution.

11. Take such action in accordance with the rules, regulations and orders promulgated by the Commission as may be necessary to prevent, abate and control air pollution.

Sec. 11. (Deleted by amendment.)

Sec. 12. (Deleted by amendment.)

Sec. 13. (Deleted by amendment.)

Sec. 14. NRS 445B.590 is hereby amended to read as follows:

445B.590 1. The Account for the Management of Air Quality is hereby created in the State General Fund, to be administered by the Department.

2. Money in the Account for the Management of Air Quality must be expended only:

(a) To carry out and enforce the provisions of NRS 445B.100 to 445B.640, inclusive, and ***sections 2 to 6.5, inclusive, of this act and*** of any regulations adopted pursuant to those sections, including, without limitation, the direct and indirect costs of:

(1) Preparing regulations and recommendations for legislation regarding those provisions;

(2) Furnishing guidance for compliance with those provisions;

(3) Reviewing and acting upon applications for operating permits;

(4) Administering and enforcing the terms and conditions of operating permits;

(5) Monitoring emissions and the quality of the ambient air;

(6) Preparing inventories and tracking emissions;

(7) Performing modeling, analyses and demonstrations; and

(8) Establishing and administering a program for the provision of assistance, pursuant to 42 U.S.C. § 7661f, to small businesses operating stationary sources; and

(b) In any other manner required as a condition to the receipt of federal money for the purposes of NRS 445B.100 to 445B.640, inclusive ~~.~~ ***, and sections 2 to 6.5, inclusive, of this act.***

3. All interest earned on the money in the Account for the Management of Air Quality must be credited to the Account. Claims against the Account for the Management of Air Quality must be paid as other claims against the State are paid.

Sec. 15. NRS 445B.600 is hereby amended to read as follows:

445B.600 NRS 445B.100 to 445B.595, inclusive, ***and sections 2 to 6.5, inclusive, of this act*** does not abridge, limit, impair, create, enlarge or otherwise affect substantively or procedurally the right of

any person to damages or other relief on account of injury to persons or property and to maintain any action or other appropriate proceeding therefor in the courts of this State or the courts of the United States on a tort claim against the United States or a federal agency as authorized by federal statutes.

Sec. 16. NRS 445B.610 is hereby amended to read as follows:

445B.610 1. All rules, regulations and standards promulgated by the State Commission of Environmental Protection pertaining to air pollution control in force on July 1, 1973, ~~[shall]~~ remain in effect until such time as revised by the State Environmental Commission pursuant to NRS 445B.100 to 445B.640, inclusive ~~[.]~~ ***, and sections 2 to 6.5, inclusive, of this act.***

2. Any and all action taken by the State Commission of Environmental Protection, including but not limited to existing orders, notices of violation, variances, permits, cease and desist orders and compliance schedules, shall remain in full force and effect and binding upon the State Environmental Commission, the Director, the Department and all persons to whom such action may apply on or after July 1, 1973.

3. In the event that a local air pollution control program described in NRS 445B.500 is transferred in whole or in part from an existing air pollution control agency to another agency, all rules and regulations adopted by the existing agency may be readopted as amended to reflect the transfer of authorities by the new agency immediately upon such transfer, and the provisions of NRS 445B.215 ~~[shall]~~ ***do*** not apply to such readoption.

4. If a transfer of local authority as described in subsection 3 occurs, all orders, notices of violation, variances, cease and desist orders, compliance schedules and other legal action taken by the existing air pollution control board, control officer ~~[,]~~ or hearing board ~~[shall]~~ remain in full force and effect, and ~~[shall]~~ ***must*** not be invalidated by reason of such transfer.

Sec. 17. NRS 445B.640 is hereby amended to read as follows:

445B.640 1. Except as otherwise provided in subsection 4 and NRS 445C.010 to 445C.120, inclusive, any person who violates any provision of NRS 445B.100 to 445B.450, inclusive, and 445B.470 to 445B.640, inclusive, ***and sections 2 to 6.5, inclusive, of this act,*** or any regulation in force pursuant thereto, other than NRS 445B.570 on confidential information, is guilty of a civil offense and shall pay an administrative fine levied by the Commission of not more than $10,000 per day per offense. Each day of violation constitutes a separate offense.

2. The Commission shall by regulation establish a schedule of administrative fines not exceeding $500 for lesser violations of any provision of NRS 445B.100 to 445B.450, inclusive, and 445B.470 to 445B.640, inclusive, ***and sections 2 to 6.5, inclusive, of this act,*** or any regulation in force pursuant thereto.

3. Action pursuant to subsection 1 or 2 is not a bar to enforcement of the provisions of NRS 445B.100 to 445B.450, inclusive, and 445B.470 to 445B.640, inclusive, ***and sections 2 to 6.5, inclusive, of this act,*** regulations in force pursuant thereto, and orders made pursuant to NRS 445B.100 to 445B.450, inclusive, and 445B.470 to 445B.640, inclusive, ***and sections 2 to 6.5, inclusive, of this act*** by injunction or other appropriate remedy, and the Commission or the Director may institute and maintain in the name of the State of Nevada any such enforcement proceedings.

4. Any person who fails to pay a fine levied pursuant to subsection 1 or 2 within 30 days after the fine is imposed is guilty of a misdemeanor. The provisions of this subsection do not apply to persons found by the court to be indigent.

5. All administrative fines collected by the Commission pursuant to this section must be deposited in the county school district fund of the county where the violation occurred.

Sec. 18. NRS 445C.030 is hereby amended to read as follows:

445C.030 "Environmental requirement" means a requirement contained in NRS 444.440 to 444.645, inclusive, 445A.300 to 445A.730, inclusive, 445B.100 to 445B.640, inclusive, ***and sections 2 to 6.5, inclusive, of this act,*** 459.400 to 459.600, inclusive, 459.700 to 459.856, inclusive, or 519A.010 to 519A.280, inclusive, or in a regulation adopted pursuant to any of those ~~[statutes.]~~ ***sections.***

Sec. 19. NRS 459.460 is hereby amended to read as follows:

459.460 1. NRS 459.400 to 459.600, inclusive, do not apply to any activity or substance which is subject to control pursuant to NRS 445A.300 to 445A.955, inclusive, and 459.010 to 459.290, inclusive, except to the extent that they can be applied in a manner which is not inconsistent with those sections.

2. The Director shall administer NRS 459.400 to 459.600, inclusive, in a manner which avoids duplication of the provisions of NRS 445A.300 to 445A.955, inclusive, and 445B.100 to 445B.640, inclusive, ***and sections 2 to 6.5, inclusive, of this act,*** and the Federal Insecticide, Fungicide, and Rodenticide Act, 7 U.S.C. §§ 136 et seq.

Sec. 20. NRS 459.930 is hereby amended to read as follows:

459.930 1. Notwithstanding any other provision of law to the contrary and regardless of whether he is a participant in a program, a person who:

(a) Is a bona fide prospective purchaser is not liable for any response action or cleanup that may be required with respect to any real property pursuant to NRS 445A.300 to 445A.730, inclusive, 445B.100 to 445B.640, inclusive, ***and sections 2 to 6.5, inclusive, of this act,*** 459.400 to 459.600, inclusive, or any other applicable provision of law.

(b) Is an innocent purchaser is not liable for any response action or cleanup that may be required with respect to any real property pursuant to NRS 445A.300 to 445A.730, inclusive, 445B.100 to 445B.640, inclusive, ***and sections 2 to 6.5, inclusive, of this act,*** 459.400 to 459.600, inclusive, or any other applicable provision of law.

(c) Owns real property that:

(1) Is contiguous to or otherwise similarly situated with respect to; and

(2) Is or may be contaminated by a release or threatened release of a hazardous substance from,

➥ other real property that the person does not own, is not liable for any response action or cleanup that may be required with respect to the release or threatened release, provided that the person meets the requirements set forth in section 107(q)(1) of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, 42 U.S.C. § 9607(q)(1).

2. A person described in paragraph (a), (b) or (c) of subsection 1 shall report to the Division, in a manner prescribed by the Commission:

(a) Any of the following substances that are found on or at real property owned by the person:

(1) Hazardous substances at or above the required reporting levels designated pursuant to sections 102 and 103 of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, 42 U.S.C. §§ 9602 and 9603; and

(2) Petroleum products of such type and in such amount as are required by the Division to be reported; and

(b) Any response action or cleanup that has been performed with respect to the real property described in paragraph (a).

3. The provisions of this section do not otherwise limit the authority of the Administrator, the Commission or the Division to require any person who is responsible for the contamination or

pollution of real property, by improperly managing hazardous substances at or on that real property, to perform a response action or cleanup with respect to that real property.

4. If there are costs relating to a response action or cleanup that are incurred and unrecovered by the State of Nevada with respect to real property for which a bona fide prospective purchaser of the real property is not liable pursuant to the provisions of this section, the State of Nevada:

(a) Has a lien against that real property in an amount not to exceed the increase in the fair market value of the real property that is attributable to the response action or cleanup, which increase in fair market value must be measured at the time of the sale or other disposition of the real property; or

(b) May, with respect to those incurred and unrecovered costs and by agreement with the bona fide prospective purchaser of the real property, obtain from that bona fide prospective purchaser:

(1) A lien on any other real property owned by the bona fide prospective purchaser; or

(2) Another form of assurance or payment that is satisfactory to the Administrator.

5. The provisions of this section:

(a) Do not affect the liability in tort of any party; and

(b) Apply only to real property that is acquired on or after the date that is 60 days after May 26, 2003.

6. As used in this section:

(a) "Administrator" means the Administrator of the Division.

(b) "Bona fide prospective purchaser" has the meaning ascribed to it in section 101(40) of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, 42 U.S.C. § 9601(40).

(c) "Commission" means the State Environmental Commission.

(d) "Division" means the Division of Environmental Protection of the State Department of Conservation and Natural Resources.

(e) "Hazardous substance" has the meaning ascribed to it in NRS 459.620.

(f) "Innocent purchaser" means a person who qualifies for the exemption from liability set forth in section 107(b)(3) of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, 42 U.S.C. § 9607(b)(3).

(g) "Participant" has the meaning ascribed to it in NRS 459.622.

(h) "Program" means a program of voluntary cleanup and relief from liability set forth in NRS 459.610 to 459.658, inclusive.

(i) "Response action" means any action to mitigate, attempt to mitigate or assist in the mitigation of the effects of a leak or spill of or an accident involving a hazardous substance, including, without limitation, any action to:

(1) Contain and dispose of the hazardous substance;

(2) Clean and decontaminate the area affected by the leak, spill or accident; or

(3) Investigate the occurrence of the leak, spill or accident.

Sec. 21. This act becomes effective on July 1, 2007.

Exhibit B:

Nevada SEC Proposed Regulation R.142-07

BAQP PROPOSED REVISIONS TO THE GHG PROVISIONS OF:

PROPOSED REGULATION OF THE
STATE ENVIRONMENTAL COMMISSION
LCB File No. R142-07

December 4, 2007

EXPLANATION – Matter in blue ***italics*** is the LCB draft of NDEP's proposed GHG regulation. NDEP's proposed revisions to the LCB draft are underlined (green indicates added language; pink ~~strikeout~~ indicates deletions).

* * * * * * * * * * * *

Greenhouse Gas Provisions

Sec. 4. ***"Affected unit" has the meaning ascribed to it in NRS 445B.370.***

Sec. 5. ***"Greenhouse gas" has the meaning ascribed to it in NRS 445B.137.***

Sec. 6. ***"The Climate Registry" means the organization established by states, tribes and provinces in North America as a mechanism to ~~measure~~ report greenhouse gas emissions ~~consistently~~ across borders and industry sectors using consistent protocols and in a consistent format.***

Sec. 7. ***"The California Climate Action Registry" means the organization established in California as a mechanism to report greenhouse gas emissions using consistent protocols and in a consistent format.***

Sec. 8. ***1. Information regarding ~~The Climate Registry~~ the California Climate Action Registry may be obtained at the website ~~www.theclimateregistry.org~~ www.climateregistry.org.***

2. The owner or operator of ~~a new or existing~~ an affected unit must report all greenhouse gases emitted by each affected unit to ~~The~~ the California Climate Action Registry , beginning with calendar year 2008 data. The owner or operator must comply with the following provisions established by ~~The~~ the California Climate Action Registry:

(a) The requirements and procedures for reporting emissions of greenhouse gases;

(b) The methods for determining the emissions of greenhouse gases that must be reported for inclusion in ~~The~~ the California Climate Action Registry;

(c) The methods for independently verifying the information reported for inclusion in ~~The~~ the California Climate Action Registry; and

(d) The reporting period, which must not exceed 1 year.

Sec. 9. *1. Information regarding The Climate Registry may be obtained at the website www.theclimateregistry.org.*

2. At such time as The Climate Registry is fully developed, implemented and operational, as determined by the Director, compliance with sections 8 and 10 of this regulation shall be met by participation in either The Climate Registry or the California Climate Action Registry. If The Climate Registry and the California Climate Action Registry are merged, compliance with sections 8 and 10 of this regulation shall be met by participation in The Climate Registry.

Sec. 10. *On or before ~~July 1, 2009, and on or before July 1 of each year thereafter,~~ the date required by the California Climate Action Registry or The Climate Registry for submittal of the preceding year's greenhouse gas emissions data, the owner or operator of an affected unit shall notify the Director that the report required pursuant to section ~~7~~ 8 of this regulation has been submitted to the California Climate Action Registry or The Climate Registry.*

Sec. 11. *1. The State Department of Conservation and Natural Resources shall, not later than December 31, 2008, and at least every 4 years thereafter, issue a statewide inventory of greenhouse gases emitted in this State.*

2. The inventory issued pursuant to subsection 1 must include, without limitation:

(a) The origins, types and amounts of those greenhouse gases;

(b) The Department's analysis of the information set forth in paragraph (a); and

(c) Documentation for the information set forth in paragraphs (a) and (b).

Exhibit C:

Nevada SEC December 4, 2007 Meeting Agenda

State of Nevada
Dept. of Conservation & Natural Resources
State Environmental Commission sec.nv.gov
901 South Stewart Street, Suite 4001 -- Carson City, Nevada 89701-5249

SEC Meeting Agenda

December 04, 2007

The State Environmental Commission (SEC) has scheduled a regulatory hearing for Tuesday, December 4th, 2007 beginning at 9:30 am. The hearing will be held at the Nevada Department of Wildlife's Conference Room A, 1100 Valley Road, Reno, Nevada.

As required by the provisions of chapters 233B and 241 of Nevada Revised Statutes, this meeting agenda has been posted at the following locations: the Department of Wildlife in Reno, the Grant Sawyer Office Building in Las Vegas, the Nevada State Library in Carson City and at the Offices of the Division of Environmental Protection in Carson City and Las Vegas.

Copies of this agenda and the information noted below were made available to all public libraries throughout the state as well as individuals on the SEC electronic mailing lists. The Public Notice for this hearing was also published on three separate occasions during November 2007 in the Las Vegas Review Journal and the Reno Gazette Journal newspapers. Additional information in support of this agenda is located on the SEC website at sec.nv.gov

The following items will be discussed and acted upon but may be taken in different order to accommodate the interests and time of the persons attending.

1) Approval of minutes from the September 07, 2007 SEC hearing *ACTION

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2) Approval of the following Settlement Agreements - Air Quality Violations *ACTION by Consent Calendar:

Company Name

1. Brady Power Partners
2. Carson City Renewable Resources
3. Wilkin Mining and Trucking, Inc

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3) Approval of Arsenic Rule Exemptions for the following list of water systems *ACTION by Consent Calendar

WATER SYSTEM ID #	SYSTEM NAME
NV0003068	CARSON RIVER ESTATES
NV0000047	DELUXE MHP
NV0000906	JETWAY CHEVROLET
NV0000060	WEST STAR MHP
NV0000058	WILDES MANOR
NV0000162	MC DERMITT WATER SYSTEM
NV0000897	SCHURZ ELEMENTARY SCHOOL
NV0000218	CARVERS SMOKEY VALLEY RV AND MHP
NV0005028	SHOSHONE ESTATES WATER COMPANY
NV0000878	MASTERFOODS USA

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4) Nevada State Solid Waste Management Plan *Action

Nevada's Solid Waste Management Plan (Plan) provides a description of the existing framework for solid waste management within the applicable laws, regulations and infrastructure within the State. The Plan describes governmental roles and responsibilities, statewide trends in solid waste management, the assessment of Nevada's municipal solid waste management systems, and solid waste management issues and future considerations.

Nevada Revised Statute NRS 444.570 requires the State Environmental Commission (SEC), in cooperation with governing bodies of Nevada's municipalities, to develop a statewide solid waste management plan. The plan is reviewed and revised every five years. This Plan is intended to fulfill this requirement and to provide guidance, and information to support:

1. Adoption of solid waste management regulations by the SEC;

2. Efforts undertaken by the Nevada Division of Environmental Protection (NDEP) before the Nevada Legislature regarding the allocation of solid waste program resources;

3. Development and implementation of solid waste management plans and ordinances administered by Nevada's municipal governments; and

4. Activities by other stakeholders who provide solid waste services to the communities, businesses and residents of Nevada. The Plan is available at: http://ndep.nv.gov/bwm/swmp/swp01.htm

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Regulatory Petitions for Waste Management -- *Action Items

5) Regulation R179-05: Waste Landfill Cover Requirements: This regulation addresses "cover requirements" of compacted solid waste at certain landfills in Nevada. The regulation would amend NAC 444.688. The requested change will reverse an existing requirement that allows certain landfills in Nevada to operate for up to six days without applying cover soil to exposed waste.

By way of background, Nevada has received approval from the Environmental Protection Agency (US EPA) to administer federal municipal solid waste landfill (MSWLF) regulations contained in 40 CFR Part 258. Under the approved program, the Clark and Washoe County Health Districts (Las Vegas & Reno) administer the landfill regulations within their areas of jurisdiction, while the Nevada Division of Environmental Protection (Division) does so in all other areas of the state.

The federal MSWLF regulations require municipal landfills to cover disposed solid waste at the end of each operating day (40 CFR § 258.21). Certain MSWLFs in Nevada have claimed to operate "around the clock", suggesting that for them there is no "end of each operating day" that would trigger the daily cover requirement.

In recognition of the potential need to receive waste around the clock at landfills that serve the "24-hour" urban areas of Las Vegas and Reno, in 1998 the State Environmental Commission adopted revisions to NAC 444.688 that allowed such landfills to operate for up to 6 days prior to applying cover material. To make this allowance, the term "operating day" at such landfills was defined to include a period of time up to six days long. The US EPA has since notified the Division that this language is not consistent with the federal criteria.

This regulation would therefore restore conformance with the federal landfill criteria while retaining flexibility for landfills to operate continuously. This regulation would allow landfills to avoid the requirement of a daily cover if they have equipment continuously "working the face" of the landfill.

An immediate and long-term adverse financial effect would impact certain operators. Such costs could also increase disposal fees for the public. There would, however, be no additional cost to the Division for enforcement of the proposed regulation, and the regulation does not overlap or duplicate any

regulations of other state, federal, or local agencies. The regulation would also not increase fees levied by the Division (SEC reference # P2005-10).

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6) Regulation R137-07: Adoption by Reference, Hazardous Waste: This petition will amend regulations governing hazardous waste management found in Chapter 444 of the Nevada Administrative Code (NAC). The proposed amendments will update Nevada's adoption of federal regulations by reference. This will include federal regulatory changes adopted by US EPA between July 1, 2005 and July 1, 2006. The proposed amendments will allow the State to implement the "RCRA" Hazardous Waste program in lieu of the federal government.

The regulatory changes comprise the addition of mercury containing equipment to the list of universal wastes, revisions to the hazardous waste program to allow for a standardized permit, revisions of wastewater treatment exemptions for hazardous waste mixtures, the RCRA portions of national emissions standards for hazardous air pollutants from hazardous waste combustors, and changes to hazardous waste regulatory requirements to reduce the paperwork burden.

This regulation will not have an immediate or long-term adverse effect on business or the public, there is no additional cost to the agency for enforcement of the proposed regulation, and the regulation does not overlap or duplicate any regulations of other state, federal, or local agencies and it does not alter fees (SEC reference # P2007-04).

Regulatory Petitions for Corrective Actions -- *Action Item

7) Regulation R125-07: Release Reporting Regulations of Hazardous Substances or Petroleum Products in Excess of Reportable Quantities: The proposed regulation would amend the Nevada Division of Environmental Protection's (NDEP) existing release reporting regulations that are contained in Nevada Administrative Code 445A.345 to 445A.348. Release reporting regulations require facilities to notify NDEP after the release of hazardous substances or petroleum products in excess of reportable quantities. The proposed regulation makes the following changes and clarifications to the existing regulations:

- The proposed regulation creates a category of releases that will be subject to more immediate notification requirements than what the existing regulations mandate. The existing regulations allow for notification of any incident, regardless of severity or impact, within one

working day, which is not supportive of agency functions during significant events.

- Reportable triggers based on environmental media have been added for "listed" hazardous substances taken from federal regulations. This brings hazardous substances in line with the handling of petroleum products and "unlisted" pollutants and contaminants, which all have media-specific reporting requirements.

- A "discovery event" trigger has been added for the reporting of hazardous substance contamination discovered in soil or groundwater as a result of historic or prior releases. The "discovery event" trigger will be based on the existing framework for petroleum product releases.

- A clarifying definition has been added for "other surfaces of land," which was previously undefined.

- A minimum reportable quantity for "listed" hazardous substances has been adopted to be consistent with existing reportable quantities for petroleum products.

- A specific reportable trigger for releases from underground storage tanks has been added in coordination with the State's UST program.

The changes and clarifications in the proposed regulation are intended to support the Division's function as the State agency responsible for the implementation of the Nevada Water Pollution Control Law and those statutes and regulations adopted for the management of hazardous wastes, hazardous substances, and underground storage tanks. The changes and clarifications eliminate inconsistencies in the existing regulations and rely on standards of practice that already exist within most sections of the regulated community.

This regulation will not have an immediate or long-term adverse effect on business or the public, and there is no additional cost to the agency for enforcement of the proposed regulation. There are two other State agencies that have reporting provisions that may capture the same incidents as NDEP reporting requirements; they are the Nevada Department of Transportation, which is involved with hazardous material releases on the roadways, and the Nevada Department of Emergency Management, which is responsible for coordinating the State's response to any significant incident. These different release reporting requirements do not necessarily overlap each other because the State agencies may have different authorities and jurisdictions and the notification requirements may be built on entirely different reporting triggers.

The Federal government is also required to be notified after a release of a reportable quantity of hazardous substances. These reporting functions have been consolidated in the National Response Center operated by the US Coast

Guard. The release of a reportable quantity of hazardous substances is felt to be a significant event that may require response under the National Contingency Plan, (SEC reference # P2007-05).

Regulatory Petitions for Air Quality Planning / Air Pollution Control
***Action Items**

8) Regulation R142-07: Greenhouse Gas Reporting, Minor Violation Fine Increase and Permitting Corrections/Clarifications: This regulation will amend NAC 445B.001 to 445B.3497 of the State "Air Pollution" regulations, by adding the following requirements:

The regulation will mandate the reporting of greenhouse gases (GHG) emitted by certain generators of electricity for inclusion in a registry of GHG emissions, and require the Nevada Division of Environmental Protection (NDEP) to issue, at least every 4 years, a statewide inventory of GHGs released in the State. The data collection and reporting of GHG emissions is a requirement of Senate Bill 422 enacted by the 2007 Nevada Legislature (see: http://www.leg.state.nv.us/74th/Bills/SB/SB422_EN.pdf).

The regulation will revise fines for minor violations. Of note, Assembly Bill 67 was passed by the 2007 Legislature, increasing the maximum allowable fine for a minor violation to $2000 (http://www.leg.state.nv.us/74th/Bills/AB/AB67_EN.pdf). The last increase in the maximum allowable fine was 20 years ago. With this new authority, NDEP proposes to change the fine structure for minor violations to make the amounts more commensurate with today's economy. The higher fine amounts will provide a greater deterrent to violating state regulations.

The regulation will also revise the operating permits regulations in response to the U.S. Environmental Protection Agency's review of NDEP's proposed update to the Nevada State Implementation Plan. The revisions are minor, including clarifications; aligning the state definition of "federally enforceable" with the federal definition, and adding public participation requirements for Class II general permits.

Finally the regulation will revise the definition of a "Class III source" to allow a stationary compression ignition internal combustion engine (CI-ICE) that is subject to 40 CFR 60 Subpart IIII and does not exceed 750 horsepower to qualify as a Class III source. If the regulation is not adopted businesses with stand-alone emergency or backup generators must now obtain a Class II permit. The time and cost required in obtaining a Class II permit for stationary CI-ICEs that do not exceed 750 horsepower would impose undue hardship on business/industry. Hence, the proposed regulation alleviates this hardship.

Regulatory Effects: There will be added costs to electric power generating companies that operate electric generating units with a maximum design output capacity of 5 megawatts or more and emit GHGs. In carrying out the intent of new legislation, the regulation requires these companies to participate in a registry of GHGs and begin reporting emissions of six GHGs in 2009.

The regulatory changes will have a beneficial economic effect on businesses or industries that would otherwise have been required to obtain a Class II operating permit for operations of stationary compression ignition internal combustion engine.

There will be additional costs to the agency for administering the new GHG program, which will require one full-time employee. These additional costs will be covered by a settlement agreement; no new fees are required. The proposed regulations do not overlap or duplicate any regulations of other state or government agencies and they are no more stringent than what is established by federal law. The proposed amendments do not address fees, (SEC reference # P2007-06).

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9) Regulation R143-07: Nevada Clean Air Mercury Rule Program: This petition will amend NAC 445B.3711 to 445B.3791 of the State "Air Pollution" regulations. The amendment is needed to address certain technical changes to the regulations governing Nevada's Clean Air Mercury Rule Program (CAMR) including public participation requirements defined in Assembly Bill 67; AB 67 was recently enacted by the 2007 session of the Nevada Legislature (See, http://www.leg.state.nv.us/74th/Bills/AB/AB67_EN.pdf). Among other requirements, AB 67 calls for the adoption of regulations to address public participation in the determination of the amount of mercury allowances [air emissions] available for sale or auction by the Department, i.e., the Nevada Division of Environmental Protection. The amendment complies with this requirement.

Other changes to the regulation respond to US EPA's review of Nevada's CAMR State Plan, which was submitted to EPA November 15, 2006 in compliance with the Federal Clean Air Mercury Rule. The amendments are necessary to clarify Nevada's Plan, align it more closely with the Federal CAMR and, thereby, make Nevada's Plan more approvable by EPA.

This regulation will not have an immediate or long-term adverse economic effect on business or the public, there is no additional cost to the agency for enforcement of the proposed regulation, and the regulation does not overlap or duplicate any regulations of other state, federal, or local agencies and it does not alter fees (SEC reference # P2007-07).

10) Public Comment * Non Action Items: (Public comment may be limited to ten minutes per person at the discretion of the chairperson.
Reference Nevada Open Meeting Law Manual, pages 58 & Page 81)
http://ag.state.nv.us/publications/manuals/omlmanual.pdf

- NCARE - Nevada For Clean Affordable Reliable Energy: A representative from NCARE will discuss the "carbon sequestration" Memorandums of Agreements (MOU's) between NDEP and those power companies proposing coal fired electric generating facilities in Nevada.

- Other Public Comments:

- Administrator's Briefing to the Commission: NDEP's Administrator will provide the Commission an update about coal fired power plants permitting activities in Nevada. This will include the MOU's with three power companies proposing coal fired electric generating facilities in Nevada; these MOU's address certain commitments to deploy carbon sequestration technologies when such technologies become available. An update on the Divisions involvement in local and regional climate change initiatives will also be provided.

Additional Information: Copies of materials referenced in this agenda may be obtained by calling the Executive Secretary, John Walker at (775) 687-9308. The public notice and the text of materials for the meeting are also available on the State Environmental Commission website at:
http://www.sec.nv.gov/index.htm

Persons wishing to comment on the proposed actions on this agenda may appear at the scheduled public hearing or may address their comments, data, views, or arguments in written form to: State Environmental Commission, 901 South Stewart Street, Suite 4001, Carson City, Nevada 89701-5249.

The SEC must receive written submissions at least five days before the scheduled public hearing. If no person who is directly affected by the proposed action appears to request time to make an oral presentation, the SEC may proceed immediately to act upon any written submissions.

Upon adoption of any regulation, the SEC, if requested to do so by an interested person, either before adoption or within 30 days thereafter, will issue a concise statement of the principal reasons for and against its adoption and incorporate therein its reason for overruling the consideration urged against its adoption.

Members of the public who are disabled and require special accommodations or assistance at the meeting are requested to notify, in writing, the Nevada State Environmental Commission, in care of John B. Walker, Executive Secretary, 901 South Stewart Street, Suite 4001, Carson City, Nevada 89701-5249, facsimile (775) 687-5856, or by calling (775) 687-9308, no later than 5:00 p.m. on November 27, 2007.

Exhibit D:

"Supplemental Proposal of Sierra Pacific Power Company with Respect to Resource Adequacy Requirements for Small and Multi-Jurisdictional Utilities"

(filed September 10, 2007 before CPUC)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program.	Rulemaking 05-12-013 (Filed December 15, 2005)

SUPPLEMENTAL PROPOSAL OF SIERRA PACIFIC POWER COMPANY (U 903 E) WITH RESPECT TO RESOURCE ADEQUACY REQUIREMENTS FOR SMALL AND MULTI-JURISDICTIONAL LSEs

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September 10, 2007

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SUPPLEMENTAL PROPOSAL OF SIERRA PACIFIC POWER COMPANY (U 903 E) WITH RESPECT TO RESOURCE ADEQUACY REQUIREMENTS FOR SMALL AND MULTI-JURISDICTIONAL LSEs

I. Introduction

Sierra Pacific Power Company ("Sierra") submits this supplemental proposal addressing how the California Public Utilities Commission ("CPUC" or "Commission") should implement California Public Utilities ("Pub. Util.") Code § 380 for Sierra's California service territory. Sierra submits these comments in accordance with the Assigned Commissioner's Ruling and Scoping Memo dated December 22, 2006 ("ACR"), the Administrative Law Judge's ("ALJ") Ruling Clarifying and Further Modifying the Procedures and Schedule for Track 3, dated July 5, 2007, and the ALJ's email of August 22, 2007 modifying the filing date for this Proposal.

Sierra is subject to a comprehensive system of resource planning, procurement and resource adequacy requirements pursuant to Nevada law pursuant to the regulation of the Public Utilities Commission of Nevada ("PUCN"). The Nevada IRP process is functionally equivalent to the California resource adequacy ("RA") requirement ("RAR") process mandated by Public Utilities Code § 380 ("Section 380") and already meets the criteria and achieves the objectives of Section 380. Based on the PUCN's comprehensive regulatory system, and excellent track record of assuring adequate energy supplies to meet the needs of Sierra's small service territory in California, this Commission can continue to rely upon its sister agency in Nevada assuring prudent, safe and reliable service for Sierra's California customers. Rather than imposing a

duplicate set of RA requirements under Section 380 fashioned to adapt the existing CAISO-based system to Sierra's distinct circumstances, Sierra respectfully requests that the Commission continue to turn to the comprehensive resource planning processes used by the PUCN for purposes of validating Sierra's compliance with California law. Accordingly, Sierra asks that the Commission find that the Integrated Resource Planning ("IRP") process followed in Nevada satisfies the intent and purpose of Section 380 in lieu of imposing separate California-only RAR policy.

Sierra proposes to take the following actions to assure the CPUC that the Nevada IRP process continues to meet the criteria and achieve the objectives of Section 380:

(a) Make an annual Compliance Filing with the Commission by Advice Letter;

(b) Submit to the Commission updated information regarding its triennial IRP filings; and

(c) Submit to the Commission updated information regarding its annual Energy Supply Plan.

II. Sierra Is A Multi-Jurisdictional Utility (MJU) With Many Characteristics That Distinguish It From California's In-State Utilities.

Sierra provides retail electric service to the public in northern Nevada and in the Lake Tahoe area of California. Only 6% of its load is located in California. Load growth in its California service territory is relatively flat, with a forecasted average annual growth rate of 1.5% from 2009 through 2017.[1] It has few large and no direct access customers in California, and no customers of any consequence have departed Sierra's system in California.

Sierra's California customers are served on an integrated basis with Sierra's much larger Nevada service territory loads. Sierra's California service territory is completely outside the

[1] 2007 IRP, Introduction, at p. 6.

control area of the California Independent System Operator ("CAISO") and Sierra is the control area operator for its entire territory, including the California portion.

The California service territory is winter peaking. The California service territory's winter peak load is 134 MW out of a larger system winter peak load of 1,339 MW (approximately 10%). Sierra's Nevada service territory and its integrated system peak occur in summer. Sierra's California summer load is 77 MW out of a forecasted system peak of 1,647 MW for 2007 (approximately 4%). Thus, the peak winter load in California is more than sufficiently covered by the generation capacity developed to serve a Northern Nevada summer peak requirement. Sierra's California service territory has been, and continues to be, resource adequate.

Sierra is not like the three large California investor-owned electric utilities, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company ("Jumbo IOUs"). Sierra differs in the following important respects:

(1) Sierra is subject to comprehensive regulation by the PUCN, which has full jurisdiction over 94% of Sierra's customer load, and it already implements a successful IRP process;

(2) Sierra's California service territory is served by generation located entirely in Nevada (with the exception of 12 MW of emergency diesel generators located in the Tahoe basin) and is dependent on Sierra's Nevada transmission facilities for virtually all of its power;

(3) Sierra's California loads benefit from load diversity insofar as Sierra's system summer peak is significantly larger than the Californian loads' winter peak requirements;

(4) Sierra's California service territory is not part of the CAISO control area, receives negligible support from the CAISO or its member entities, and is not subject to the requirements of the CAISO[2];

[2] Although Sierra and PG&E have three interconnections, as a practical matter very little energy flows through those interconnections with regularity, although under emergency conditions they may be support north Tahoe load under emergency assistance as exports from CAISO.

(5) Sierra's integrated system does not suffer from internal load pockets or import transmission constraints;

(6) Sierra relies on power imported from outside its integrated system for a diminishing percentage of its overall supply needs; and that reliance will decrease further by June 2008 when 744 MW of new generation will come on-line in Sierra's service territory;

(7) The addition of that new generation capacity in June 2008 will make Sierra virtually self-sufficient in meeting its system summer peak load demand;

(8) The Commission has exempted Sierra from the AB 57 procurement planning compliance requirements in recognition of the comprehensive resource planning process in place in Nevada;

(9) Sierra has a relatively small and stable California load, with no direct access customers and few large customers and, as a result, faces no threat of significant load migration;

(10) Sierra does not receive power through power purchase agreements entered by the California Department of Water Resources; and

(11) Sierra has an excellent track record of resource adequacy and reliability in meeting customer loads at reasonable rates, in both California and Nevada.

III. Public Utilities Code Section 380 Does Not Require A "One Size Fits All" Approach To Resource Adequacy.

Section 380 requires California load serving entities ("LSEs") to maintain sufficient generation to meet load, including peak demand and planning and operating reserves, as well as meeting the minimum operating reserve and reliability criteria of the Western Electricity Coordinating Council ("WECC").

In setting RA requirements for each LSE, Section 380 mandates that the Commission achieve all of the following objectives:

- Facilitate development of needed new generation;
- Equitably allocate costs of new generation; and

- Minimize enforcement requirements and costs.[3]

The RAR that the Commission adopts for Sierra must meet these goals above all else. In addition, the Legislature established the following requirements for all LSEs:

- Maintain sufficient physical generating capacity to meet load;[4]
- Meet minimum planning reserve and reliability criteria approved by the WECC;[5]
- Report sufficient information to the Commission to determine compliance with RA requirements, including anticipated load, actual load, and measures undertaken by the load-serving entity to ensure resource adequacy.[6]

Finally, Section 380 also mandates that the Commission determine the "most efficient and equitable means" for meeting the objectives of the statute, for retaining existing generation that is economic, for investing in new generating capacity, and for ensuring that the cost of generating capacity is allocated equitably.[7] The most efficient means for retaining and developing needed generation, equitably allocating costs and minimizing enforcement requirements and costs is to use Sierra's IRP in Nevada to comply with the Section 380 requirements. This proposals is also the most equitable means of assuring compliance since Sierra's 2007 IRP already meets the objectives of the statute. These are the statutory mandates that the Commission must implement. The Commission does not need to develop, adapt or impose additional regulatory requirements upon Sierra to meet its statutory responsibilities of assuring resource adequacy.

While Section 380(e) contain language subjecting each load-serving entity to the same RA and Renewables Portfolio Standards ("RPS") requirements otherwise applicable to electrical

[3] Pub. Util. Code § 380(b).

[4] Pub. Util. Code § 380(c).

[5] Pub. Util. Code § 380(d).

[6] Pub. Util. Code § 380(f).

[7] Pub. Util. Code § 380(h).

corporations, that language is directed at LSEs that are not electrical corporations in order to assure equity as between types of LSEs.[8] The most reasonable interpretation of the statute that achieves the paramount objectives of Section 380(b) requires the Commission to vary requirements by utility in order to meet individual needs and address the unique physical, geographic and regulatory conditions under which each utility operates.

Individualized RAR policy implementation is also needed to satisfy Section 380(h) call for the most efficient and equitable means of achieving the RAR policy objectives of ensuring retention of and investment in needed generating capacity, equitable cost allocation. For example, if Sierra were forced to procure additional capacity under contract the costs of which it could not recover through the PUCN, then to achieve equity among customers that additional incremental California-only cost would be shifted to a fewer number of California ratepayers. This result would be inefficient and inequitable because, as shown below, such additional resources are not needed to assure the resource sufficiency of Sierra's California customers. Likewise, imposing a different set of RAR requirements on Sierra than those embedded in its IRP (approved by the PUCN) could lead to duplicate and unnecessary enforcement actions by the Commission, which conflicts with one of the paramount objectives of the statute.

The Commission should reject any argument that Section 380 requires some type of "one-size-fits all" approach for RAR policy implementation. Sierra's circumstances are unique and very distinguishable from the Jumbo IOUs. It would be unreasonable and contrary to Section 380 to require that all RA requirements be exactly the same for each LSE. Thus, Sierra requests that the Commission adopt the proposals presented here so that the California RA

[8] Senate Floor Analysis, Senate Rules Committee, Third Reading (September 6, 2005) ("Currently, the PUC's jurisdiction over ESPs is derived from general registration requirements which don't specify the ESPs' resource adequacy obligations. This bill would make the PUC's authority to apply and enforce resource adequacy requirements on ESPs unambiguous. According to the PUC, this bill minimizes, if not eliminates, any legal uncertainty over its authority to set resource adequacy standards.")

requirements for Sierra make sense and give full effect to the objectives and requirements of the statute as a whole.

IV. Sierra's 2007 Integrated Resource Plan Meets The Specific Requirements Of Public Resources Code Section 380.

A. The Integrated Resource Plan Process

Every three years, Sierra is required under Nevada law to develop and submit a twenty-year Integrated Resource Plan ("IRP" or "Resource Plan") to the PUCN for approval.[9] The purpose of the IRP is to identify long-term options and strategies for filling its customers' long term needs.

Sierra's IRP is developed through a coordinated process with input from various areas of the organization (e.g., generation, transmission, procurement, environmental, finance, renewables, energy efficiency and conservation). The main components of the IRP include:

- A Load Forecast.[10]
- A Demand Side Management Plan.[11]
- An Energy Supply Plan that addresses how Sierra will forecast load and reserve margins during the 3 years between IRP filings. The Energy Supply Plan includes a Load Forecast, price forecast, open position, power purchase procurement plan, a fuel procurement plan and risk management strategy. The Energy Supply Plan is updated each September 1 for the remainder of the three year period.[12]
- A Supply Plan addresses the long term supply side options to meet Sierra's resource requirements over the 20 year resource planning horizon. These options include consideration of new generation additions, long term purchased power contracts and transmission system additions. Various alternatives are developed and evaluated, leading to a recommendation to the PUCN of a Preferred Plan and Alternative Plan.[13]

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[9] NRS 704.741; NRS 704.742; NAC 704.920; NAC 704.9508.

[10] NAC 704.9225 and NAC 704.925.

[11] NAC 704.934.

[12] NAC 704.9482.

[13] NAC 704.937 and NAC 704.944

- A Financial Plan, which demonstrates the financial impact of the preferred plan on the utility and customer rates.[14]
- A three year Action Plan that describes the steps Sierra will take during the three year period to implement the IRP.[15]

Sierra's IRP process begins with a forecast of customer's needs for electricity ("Load Forecast"). The Load Forecast is then adjusted downwards for energy savings gained from Sierra's energy conservation and load management programs. Sierra adds a planning reserve margin ("PRM") to account for uncertainties. The difference between the adjusted Load Forecast and the amount of available generating resources, establishes the forecasted need. Other needs, such as fuel diversity, renewable energy requirements, as well as transmission and operational requirements, are taken into account.

Options are identified to meet the forecasted needs, and types and quantities of resources are compared using the latest economic tools available, to determine comparative costs and risks to customers. Alternatives are ranked and a Supply Plan, consisting of generation, transmission, market purchases and Demand Side Management ("DSM"), is developed. Both a Preferred Plan and Alternative Plan are filed with the PUCN as part of the Supply Plan. In conjunction with the Supply Plan, Sierra develops a Transmission Plan for reliably delivering the resources to loads. Sierra also develops a Financial Plan to examine the effects of capital expenditures associated with the Supply Plan, Transmission Plan, and DSM Plan on customer rates. The summation of the IRP activities is the Action Plan. The Action Plan explains the individual projects, and costs, that Sierra is requesting the PUCN to approve as part of its IRP. The 2007 Action Plan covers the years 2008, 2009 and 2010.

[14] NAC 704.9069.

[15] NAC 704.9489.

Upon submission of the IRP, the PUCN determines whether Sierra's load forecasts are reasonable and whether the IRP will provide Sierra sufficient capacity and energy to meet its load requirements with adequate reserves.[16] Sierra must seek PUCN approval through the IRP for the construction or acquisition of generation facilities, the construction of transmission lines over 200 kV, and the authority to enter into power purchase agreements ("PPAs") with terms greater than three years.[17] Sierra is also required to annually update its Energy Supply Plan. Between IRPs, Sierra formally files Amendments for approval of new generation and transmission. The actions proposed by Sierra in the IRP and the Amendments thereto are not deemed to be prudent unless and until the PUCN approves them.

B. The Contents of Sierra's 2007 Integrated Resource Plan Filing

On June 29, 2007, Sierra filed its 2008 – 2027 Integrated Resource Plan ("2007 IRP") with the PUCN.[18] The filing has been designated as PUCN Docket No. 07-06049. Pursuant to permission granted telephonically by ALJ Mark S. Wetzell on September 7, 2007, and Rules 1.10(d) and 1.13(g) of the Commission's Rules of Practice and Procedure ("Rules"), Sierra hereby incorporates by reference its 2007 IRP, which was filed on August 3, 2007, in R.06-02-012 as an exhibit to *Response of Sierra Pacific Power Company to Administrative Law Judge's Ruling Requiring Submission of Multi-Jurisdictional Utilities 2007 Integrated Resources Plans*. Sierra is incorporating the 2007 IRP by reference because it is very voluminous. Similarly, and pursuant to Rules 1.9(c) and 1.10 of the Commission's Rules, Sierra filed a Notice of Availability of the 2007 IRP and served on all parties to that proceeding a link to a dedicated

[16] NRS 704.746.3; NAC 704.949.

[17] NAC 704.9489(1)(D).

[18] Legislation adopted by the Nevada Legislature earlier this year extends the time for the PUCN to review and approve Sierra's IRP from 135 days to 180 days.

webpage on the Sierra website where the entire 2007 IRP can be conveniently viewed and searched. That webpage can be accessed at http://www.sierrapacificresources.com/ftp/ir/.

The 2007 IRP employs a strategy, approved by the PUCN, of growing internal generating capacity in an effort to reduce reliance on purchased power, and thus reduce exposure to market volatility.[19] With the completion of a 541 MW combined cycle plant at the Tracy Station near Reno, Nevada, Sierra will meet 98% of its forecasted need (including the 15% PRM) with internal generation. This unit is scheduled to come on line in June 2008.

On a long term basis, Sierra is partnering with Nevada Power Company to construct 1,500 MWs of reliable, baseload power station near Ely, Nevada, as well as a 250-mile transmission line to interconnect the systems of Sierra and Nevada Power. The first of the two 750 MWs units is expected to come on line in 2012. These units will further bolster Sierra's internal generating capacity and self-sufficiency. In addition, the transmission line will enable Sierra to access substantial wind power capacity in eastern Nevada.

Generally speaking, Sierra develops its Load Forecast by gathering trending information from a number of industry-accepted sources and analyzing them using various econometric models. For example, Sierra forecasts energy sales for several classes of customers through econometric modeling. The econometric models are normalized for weather, with "normal" defined as a twenty-year average of heating degree days and cooling degree days. On the other hand, Sierra bases its forecasts of expected sales to large commercial and industrial class customers on discussions with Sierra's Major Account Executives. These comparatively large customers tend to be insensitive to weather so these forecasts are not normalized. Annual sales for each customer class are allocated to each hour of the year based on unique load profiles.

[19] 2007 IRP, Introduction, at p. 3.

Sierra uses the proprietary Hourly Electric Load Model ("HELM") to derive hourly system demand forecasts.

Sierra experienced a weather normalized system (summer) peak in 2006 of 1,657 MW. This represents a 2.5% *decrease* over 2005. The decrease in system peak was due to the departure of Sierra's largest customer, Barrick Gold Mine, in 2005. As a result of this and the departure or closure of four other mines in 2007, Sierra's system peak is not expected to grow over the next two years. Thereafter, system peak (and energy sales) is forecasted to grow at an annual rate of 1.5% through 2017. Sierra's low, high, and base case load forecasts through 2017 are shown in Figure S-2 of the 2007 IRP.[20] Sierra's forecasted need is based upon its base forecast of annual system energy and on system peak.[21]

Sierra's system Load Forecast in Figure S-2 also reflects load reductions caused by the DSM Plan. Sierra is fully committed to DSM and pursuant to Nevada A.B. 3 and resource planning regulations, Sierra is maximizing its energy efficiency projects as part of its Nevada renewables Portfolio Standard. In 2006, Sierra's DSM programs reduced demand by an estimated 14.319 MW.[22] The new 2008-2010 DSM Plan expands the program significantly. The DSM Plan budget is $29.8 million over three years with an expected lifetime energy savings of approximately 1.6 billion kWh.[23] The combined effect of Sierra's portfolio of DSM programs on Sierra capacity obligation is estimated to be 23.9 MW.[24]

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[20] Figure S-2 (Annual Energy and System Peaks) and Figure S-4, (Loads and Resources Table), are found in the IRP summary materials, pages 7 and 16 respectively. The IRP Summary is posted at: http://www.sierrapacificresources.com/ftp/ir/files/CPUC_SPPC_IRP/2007_Resource%20Plan/1st%20VOLUME%20%20SUMMARY/SPP%20Volume%20I%20Summary.pdf. Both documents are included as Attachment A to this filing.

[21] 2007 IRP, Introduction, at p. 7.

[22] 2007 IRP, Volume V, at p. 34.

[23] 2007 IRP, Introduction, at p. 8.

[24] 2007 IRP, Volume V, at p. 47.

Several questions posed to Sierra and PacifiCorp by the Jumbo IOUs at the June 20, 2007 CPUC MSJU RAR workshop concern whether the California Energy Commission ("CEC") should review Sierra's load forecasts, correct them for "plausibility", and adjust them for coincident peak demand in the California system. Such questions illustrate a lack of understanding by the Jumbo IOUs of the operational characteristics of Sierra Pacific. Sierra is a multi-jurisdictional utility with 94% of its load located in the state of Nevada, and its California territory is not part of the CAISO system. It has a winter peaking service territory in California of only 134 MW. At most, the CEC has authority and perhaps the expertise to review Sierra's load forecast for its California service territory and put Sierra's summer peak into context with the California summer peak. But to suggest the CEC should be reviewing Sierra's system load forecast or making coincident adjustments to its California loads does not make sense. The CEC does not likely have the capability (nor the inclination in Sierra's view) to review Sierra's load forecasts for all of Nevada. In any event, the exercise of reviewing Sierra's forecasts for California are meaningless with respect to resource adequacy in California since: (1) the California customers are served from Nevada and are not integrated with the rest of California's loads; and, (2) Sierra has a huge surplus of capacity to serve its California customers in the winter. Accordingly, Sierra does not believe it is relevant or appropriate to impose the load forecasting mechanics applicable to IOUs within the CAISO system on Sierra's load forecasting and resource planning information.

C. Sierra's Energy Supply Plan Provides For Sufficient Physical Generating Capacity To Meet Sierra's System Peak Load Forecast Including A 15% System Planning Reserve Requirement.

Sierra's 2007 IRP demonstrates that Sierra integrated system has the total available resources (generation, purchases and transmission) to meet its California winter peak and

summer system peak loads while maintaining a 15% planning reserve margin. Sierra's previous planning reserve criteria was based on the loss of its single largest unit plus 5% of the load responsibility.[25] Its reserve margin comports with the WECC's Power Supply Design Criteria. Sierra's largest unit is currently its half of Valmy 2 in Valmy, NV, or 134 MW. Under this criteria Sierra's planning reserve for July 2007 would be 195 MW or 12% of its system peak load forecast. Historically, Sierra has had fairly weak transmission interconnections so it has been necessary to have adequate reserves available to replace the loss of its largest single unit. However, with the completion of its planned resource additions in 2008, Sierra's transmission system will be less heavily loaded. Sierra will be able to draw on the assistance of neighboring systems and increase its reliance on the power pool reserve sharing agreement. Moreover, the addition of the Tracy combined cycle unit will increase the size of its largest single contingency from 134 MW to 271 MW. If Sierra continued to use the previous planning criteria its planning reserve margin would increase to nearly 20%. Therefore, Sierra has recommended to the PUCN to change its planning reserve margin to a fixed 15% value. The 15% planning reserve margin recommendation is based upon a loss of load probability ("LOLP") analysis. The 15% planning reserve corresponds to a loss of load probability of one day in 10 years. The 2008 planning reserve margin that Sierra has proposed to the PUCN is consistent with the planning reserve margin obligation that the Commission has set for the Jumbo LSEs and which underpins its RAR policy.[26]

As discussed above, completion of the new Tracy combined cycle unit is planned for June 2008. At approximately the same time, Newmont Nevada Energy Investment LLC ("Newmont") has scheduled completion of a 203 MW coal-fired steam plant. Sierra has

[25] 2007 IRP, Volume VI, at p. 41.

[26] See, D.04-01-050; D.04-10-035.

negotiated a contract with Newmont that would provide 100% of the plant output to Sierra and Sierra would then serve the Newmont load under a new rate schedule. This contract has been submitted to the PUCN and Sierra is awaiting PUCN approval. Under the proposed contract, the Loads and Resources ("L&R") Table (Figure S-4) in the 2007 IRP Introduction would show the entire Newmont plant as a Sierra resource and Sierra's load forecast would continue to include the Newmont load.

According to Sierra's 2007 IRP, Sierra's Load Forecast estimates a system peak load of 1,641 MW in 2008, according to its base forecast.[27] A 15% planning reserve requirement adds another 246 MW, totaling 1,887 MW in required resources for 2008. Beginning in the summer of 2008, Sierra will have firm generation and purchase power resources of 2,011 MW,[28] which is well in excess of the 1,887 MW that it needs to maintain a 15% planning reserve margin for the system's peak load next summer. Thus, Sierra's planned additions to its portfolio of internal generation will eliminate Sierra's modest open position at the start of 2008, and reduce it dramatically throughout the 20-year IRP planning period.[29]

The L&R Table lists the capacity resources available to serve forecasted customer load. Resources are broken down into existing and planned internal generation, firm purchase power, including existing QFs and renewables, as well as internal (within Sierra's system) and external (outside of Sierra's system) firm power contracts. Available internal capacity is forecasted to increase by 744 MW in summer (781 MW in winter). This will eliminate any short capacity position by June 2008. External generation that Sierra purchases requires system import transmission capacity. Some resources located in specific locations within Sierra's system

[27] 2007 IRP, Introduction, Figure S-2, at page 7.

[28] 2007 IRP, Introduction, Figure S-4 at page 16.

[29] *Id.*

impact this import capacity. Sierra's total available import capacity is shown at the bottom section of the L&R Table. Sierra has roughly 1,000 MW of import capacity. Approximately 300 MW is obligated to network and pre-Order 888 commitments. This leaves significant quantities of available capacity to serve native load through imports.

In light of this information from the PUCN reviewed IRP, the CPUC should not be concerned with the adequacy of resources to meet the peak winter demand of Sierra's California customers. Sierra's system winter peak demand is estimated to be 1,325 MW, with an estimated California service territory peak of 134 MW, which together are roughly 500 MW less than Sierra's system-wide summer peak. As explained in its Purchased Power Procurement Plan in the 2007 IRP, Sierra will conduct competitive Requests for Proposals (RFPs) to procure capacity and energy products to address the modest open position during in the first half of 2008.[30] The RFPs and ensuing purchases are closely regulated, and ultimately approved, by the PUCN.

Sierra has abundant transmission capacity to assure reliable energy deliveries to its California customers. Sierra has a total transfer capacity into California that is more than sufficient to serve its greater Lake Tahoe area customers peak winter load of 134 MW even with a loss of transmission line. In addition, Sierra maintains 12 MW of diesel generators in the California service territory which can be used to supply power during emergency events.

D. The 2007 IRP Maintains Sufficient Physical Generating Capacity To Meet Load.

The 2007 IRP meets the long-term needs of Sierra's California customers through a "back to basics" strategy that emphasizes growth of internal generating capacity in an effort to reduce reliance on purchased power. As of June 2008, Sierra is expected to be virtually self-

[30] Sierra will purchase products that include a mixture of fixed price energy and capacity call options. See IRP, Volume III, at pp. 15 and 43.

sufficient in meeting its system summer peak load demand, which means that Sierra will be able to meet its relatively small California summer peak load demand of 71 MW with internal, physical generating capacity. Moreover, since Sierra's California territory is winter peaking, and since the rest of the system will have much lower demand, and whereas Sierra is expected to have 2,011 MW of available physical generating capacity at that time, it is a simple matter to see that Sierra will have abundant supplies of generating capacity to meet its California load. Therefore, Sierra complies with Pub. Util. Code § 380(c).

Maintenance by Sierra of a planning reserve margin of at least 15% provides its customers, including its California customers, a substantially greater assurance of resource adequacy than the Jumbo IOUs obtain with the same reserve margin, due to important characteristics which differentiate Sierra from the Jumbo IOUs. First, in contrast to the Jumbo IOUs, Sierra will be generation self-sufficient with the completion of the Tracy CC unit and the Newmont plant. Combined with its portfolio of long-term power purchase agreements, Sierra will not need to rely on year-ahead, month-ahead, day-ahead, and spot markets for its needs. Second, all of Sierra's generating units and almost all of the plants with which it has power purchase agreements are located within its service territory, which is free of transmission constraints. Finally, to the extent Sierra must obtain power from outside its territory, it has excess import transmission capacity. Thus, Sierra simply does not face the same types of supplying challenges which the Jumbo IOUs must address and which drive many of the Commission's RA implementation requirements.

E. Sierra Meets Minimum Planning Reserve And Reliability Criteria Approved By The Western Electricity Coordinating Council ("WECC").

Sierra is a member of the WECC. The WECC has been responsible for overseeing transmission system reliability in the Western Interconnection since 2002, when the WECC was

formed from predecessor reliability organizations. The WECC's predecessor, the WSCC, developed Minimum Operating Reliability Criteria (MORC) that included Operating Reserve requirements recognized by all WECC members. The WSCC defined Operating Reserve as capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. MORC provides flexibility in meeting Operating Reserve requirements so long as the Control Area Operator meets the minimum requirements established by the WSCC and the North American Electric Reliability Corporation (NERC). Sierra has consistently met MORC requirements.

Pursuant to the Electricity Modernization Act of 2005, which is Title XII, Subtitle A, of the Energy Policy Act of 2005 (EPAct 2005),[31] new section 215 to the Federal Power Act requires a FERC-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards.[32] Accordingly, the WECC approved and the NERC submitted to the FERC for approval eight proposed regional Reliability Standards for the WECC.[33] On June 8, 2007, the FERC approved the proposed regional Reliability Standards, including a Regional Reliability Standard (WECC-BAL-STD-002-0) to address Operating Reserve requirements for Balancing Authorities, such as Sierra.[34] The FERC also directed the WECC to develop several specific modifications to the regional Reliability Standards when the WECC develops, through its Reliability Standards development process, permanent, replacement

[31] Energy Policy Act of 2005, Pub. L. No. 109-58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005), *to be codified at* 16 U.S.C. § 824o.

[32] 16 U.S.C. §§ 824o(c)-(e).

[33] On April 19, 2007, the FERC accepted the WECC as an ERO organized on an Interconnection-wide basis. *North American Electric Reliability Corp.*, 119 FERC ¶ 61,060 at P 432 (2007) ("April 19 Order").

[34] *Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications,* 119 FERC ¶ 61,260 (June 8, 2007)

Reliability Standards. Sierra expects that these modifications to be submitted to the FERC in October.

The WECC-BAL-STD-002-0 requires that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of firm load following transmission or generation contingencies. It also requires each Balancing Authority or the reserve sharing group to maintain minimum Operating Reserves, consisting of Regulating Reserve, Contingency Reserve and additional reserves for on-demand obligations. Further, the new Standard requires that each Balancing Authority provide a minimum reserve of 5% of the loads served by hydro generation and 7% of the loads served by thermal generation.[35]

As its own control area operator, Sierra is responsible for meeting these reserve and reliability criteria. As discussed above, Sierra will have a 15% PRM, which is sufficient reserves to meet these new requirements. Sierra will comply with the new Regional Reliability Standard when it becomes final and enforceable and will provide all sufficient documentation to the Commission attesting to its compliance once the appropriate procedures are fixed by the WECC. Therefore, Sierra complies with Pub. Util. Code § 380(d).

F. Sierra Will Report Sufficient Information To The Commission To Show Its Compliance With RAR, Including Anticipated Load, Actual Load, And Measures Undertaken By The Load-Serving Entity To Ensure Resource Adequacy.

Sierra proposes to submit an annual Advice Letter (AL) filing to the Energy Division, in a form like that found in Attachment B, with periodic updates as other regulatory events warrant. The AL filing would describe load forecasts for both the California winter peak and Sierra's

[35] WECC's Minimum Operating Reserve Criteria requires Balancing Authorities like Sierra to maintain contingency reserves equal to the greater of the loss of generating capacity resulting from the most severe single contingency or the sum of five percent of load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation. Given the primarily thermal make-up of its resources base, Sierra simply refers to the 7% reserve requirement.

system peak. The filing would indicate the spectrum of resources secured to satisfy Sierra's total integrated multi-state system requirement covered by its single control area, and how its resources satisfy the WECC'S Regional Reliability Standard in addition to maintaining a PRM of approximately 15%. Filings at the CPUC would be supplemented when Sierra supplements its 2007 IRP (and subsequent IRPs) at the PUCN with changes to either loads or resources that materially affect its planning reserve margin. For example, when Sierra files an amendment to its IRP with the PUCN with respect to a new resource, Sierra would also provide it to the California Commission.

An annual AL filing is sufficient to assure the Commission that Sierra maintains sufficient resources to meet forecasted need because of the relative stability of its system requirements. Sierra's forecast system load is expected to grow at a modest pace, and its in California is growing at a slower pace. With few large customers in California and few concerns about customer migration, Sierra's load is stable. Correspondingly, Sierra's supply is stable. A review of the L&R Table shows that its existing internal generation facilities will continue to operate at the same levels through at least 2013, and its existing and planned generation will grow steadily (especially in the renewables area), once the PacifiCorp contract ends in 2009. Also, Sierra has no large intermittent resources that could change the stability of its resource profile. This contrasts to the CAISO's increasing need for additional fast ramping and load-following capacity to manage the system around intermittent energy production. Accordingly, there is little reason to require Sierra to report on its loads and resources more than once a year.

As demonstrated above, Sierra's 2007 IRP and annual Energy Supply Plans will contain sufficient information for the Commission to determine Sierra's compliance with the statute's resource adequacy requirements. Sierra does not anticipate that its annual AL filings will

include any confidential information since Sierra would report annually on loads and resources pertaining to its system and California peak load conditions. Sierra's annual filing would extract pertinent information and conclusions from the wealth of information contained in Sierra's PUCN filings so as to minimize the administrative burden on the Commission to confirm its compliance with RA requirements. Thus, an annual Advice Letter filing would comply with Pub. Util. Code § 380(f).

V. Sierra Takes A Conservative Approach Toward Counting Available Resources.

Included in questions posed by the Jumbo IOUs at the June 20 workshop is how the Commission's counting rules for Qualifying Capacity should apply to resources procured by the multi-jurisdictional utilities ("MJUs"). Sierra believes that the way it develops its IRP and its use of standard industry planning techniques properly reflects the total quantity of capacity that can be prudently relied upon.

As a general matter, Sierra submits that while the concept of Net Qualifying Capacity used in the CAISO Tariff and CPUC program is understandable, it is unnecessary for Sierra to apply those counting conventions in its circumstances. First of all, as its own control area operator, Sierra is responsible for determining the capacity values of resources used to serve its loads. Second, the Net Qualifying Capacity convention developed for the CAISO-based IOUs is needed, in part, to make sure this is no double selling or other accounting problems within the CAISO control area. Again, this is not an issue for Sierra because it is its own control area operator subject to the WECC / NERC reliability rules. Third, because Sierra must seek approval of its IRP and supply plans from the PUCN (a process that the CPUC has historically deferred to in the case of Sierra), there are serious regulatory and practical problems with imposing another, potentially conflicting capacity counting conventions. Rather than imposing

another set of metrics, Sierra believes it is most efficient and equitable for the CPUC to determine that the existing IRP processes achieve the RA policy goals.

An example of the problem with imposing a duplicate capacity counting methodology to Sierra goes as follows: The RA rules include a methodology for determining the amount of load reduction that should be attributed to particular demand response programs. Besides differences in demand response programs administered in Nevada and California, Sierra can not agree to a methodology for counting load reduction that is not approved by the PUCN. Similarly, the Commission's counting rules address whether to "gross-up" the Qualifying Facility ("QF") historical performance rate in California out of a concern over equitable treatment between QF contracts and other resources.[36] Issues such as historical performance of QFs in California make no sense in Sierra's circumstances and have little to do with maintaining adequate resources to meet its forecasted need. While Sierra does purchase energy from a small number of QFs, including one in California, those purchases are a small amount of the resources counted on by Sierra to meet load obligations. Discounting QF supplies pursuant to a California historical outage rate is inapposite and Sierra would be hard-pressed to justify this approach to the Nevada Commission. There are other examples that Sierra could cite for why the Commission's RA counting conventions are problematic, such as the inapplicability of DWR contract obligations or the irrelevance of the California ISO Tariff for Sierra.

Rather than imposing the CAISO-centric RA program implementation approach here, Sierra recommends that its IRP clearly demonstrates that Sierra takes a conservative approach to counting capacity resources and procurement planning. Simply put, Sierra will not count resources' capacity unless it is confident that those resources can be dispatched when called

[36] D.04-10-035, *Workshop Report*, at p. 22-23.

upon. Sierra does not count capacity from intermittent wind generation but instead assumes a certain quantity of energy production over the course of a year. The reflects the fact that other capacity must be on hand to reliably serve customers. Similarly, capacity provided from solar resources are discounted to reflect the fact that this generation produces only during a portion of the day and that could cover or other weather events can drop production. Similarly, the nameplate capacity from geothermal resources are derated approximately 20% to reflect the ambient derating that occurs during peak summer conditions. Accordingly, the resources listed on Sierra's L&R Table in Figure S-4 reflect the capacity values for the various resources that Sierra expects to reliably exist, consistent with prudent practices and its responsibilities as the control area operator. But from perspective of meeting the peak winter California loads, it is critical to realize that the ambient derates that occur in summer (as reflected in Sierra's L&R Table) do not come into play during the winter. Thus, the resources that Sierra is presenting to the Commission already take into account (and arguably over-estimate) the appropriate level of capacity counting.

Energy Division has also asked about Sierra's handing of load forecast error. Sierra's load forecasting process, as shown in Figure LF-2, is a multi-step process that remains relatively unchanged from those used in Sierra's recent IRP filings. Sierra presents a conceptual picture of how it performs its load forecasts in its 2007 IRP.[37] As stated, Sierra performs sales forecasts using econometric models. Model specifications for each of the econometric regressions are contained in the Load Forecast section of the Technical Appendix II (Book 1). Several key assumptions were incorporated into the regression models, including the following:

- The population of northern Nevada grows at a 2.2% average annual growth rate over the next five years;

[37] See 2007 IRP, Volume IV, at p. 3.

- Sales forecasts assumed normal weather (20-year average) encompassing the period 1997 through 2006,
- Two mines with a combined 30 MW load coincidental to peak depart Sierra's system in 2007 under Nevada AB 661;
- The closure of two mines in 2007 with a combined 38 MW load coincidental to peak;
- No new mine operations throughout the forecast horizon;
- One new GS-3 customer added annually within the large commercial and industrial rate class; and,
- New and expanded DSM programs, such as Sure Bet Commercial Incentives, Energy Star, 80 Plus, Home Energy Displays, Energy Star New Manufactured Homes, and Refrigerator Recycling, which are aimed at residential and commercial customers.

For planning purposes, low, base and high load forecast scenarios were developed, with the variance among the scenarios based on economic growth. These forecast scenarios, with DSM impacts taken into account, are contained in Figure S-2 in the Summary section of the 2007 IRP. Sierra uses its base case scenario for planning purposes as its best estimate of load in order to minimize forecast error.

Moreover, one of the purposes of the WECC reliability standards and minimum Operating Reserves is to account for load forecasting error.[38] Since Sierra meets WECC requirements, load forecasting error is offset through maintaining Operating Reserves.

Sierra was also asked about how it is presenting the energy limitations for resources. Put simply, the Maximum Cumulative Capacity ("MCC") developed for the CAISO-centric RA program is not relevant to Sierra because Sierra is its own control area operator. Sierra's resource base is not dominated by hydroelectric generation with limited energy production

[38] *WSCC Operating Reserve White Paper,* at p. 1 ("Both the NERC and the WSCC define Operating Reserve as capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection.")

capability, nor does it face material operation limitations due to environmental constraints or other issues that would significantly constrain resources' energy production. As a consequence, Sierra can plan for and work around the few resource limitations that may exist during maintenance season because it directly manages its internal resources.

Altogether, Sierra is deliberate and very conservative toward counting resources to meet forecasted need. Its process and conclusions are evaluated by the PUCN and ultimately approved or revised, if need be. Thus, Sierra submits that the California Commission should defer to the counting conventions that Sierra currently employs with the PUCN's oversight and not apply duplicate, and potentially conflicting, Qualifying Capacity rules in addition thereto.

VI. Other Elements Of The Commission's Resource Adequacy Program Designed Around The CAISO System Should Not Be Applied To Sierra Because They Are Clearly Irrelevant And Unnecessary To Assuring Resource Adequacy For Sierra's California Customers.

The Jumbo IOUs have raised other issues in their Questionnaire as part of an apparent presumption that Sierra and PacifiCorp should be required to comply with the exact same RA implementation requirements adopted for them. Following their lead would be a mistake and result in unnecessary, inefficient and inequitable results. Sierra will addresses these questions in turn.

A. Local Resource Adequacy Requirements Are Not Applicable To Sierra.

The Jumbo IOUs have posed the following questions related to the Local RAR program to the SMJUs:

- What do SMJUs view as their responsibility towards Local RAR?; and
- Do SMJUs plan to demonstrate 100% compliance with any Local RAR on September 30 [in 20 days]?"

Frankly, with respect to Sierra's operations, questions about local area constraints or load pockets are non-sequiturs. The Commission's Local RA program is inapposite to the situation

found in Sierra's transmission system. The Commission instituted the Local RA program out of a concern that LSEs could be resource-adequate on an aggregate or system basis but transmission-constrained local load pockets could still be resource-deficient.[39] The only "local" area in Sierra's system over which the Commission should be concerned regarding load pockets is Sierra's California service territory, and the Sierra's California grid is not transmission constrained and has no load pockets.[40] As explained above, Sierra's system has an excess of transmission capacity to meet capacity requirements under either winter peaking or summer peak conditions. Thus, transmission is simply not constrained into the California service territory.

Moreover—and central to the premise behind this question—because Sierra is not a part of the CAISO controlled grid, but instead is its own control area operator that can directly dispatch resources, the compliance structure for the Local RA program does not fit Sierra's circumstances. Similarly, the CAISO has conducted no local capacity requirements ("LCR") study for Sierra's integrated, multi-state service area, nor does it have the jurisdiction to do so. Accordingly, there is no LCR study upon which to establish local procurement obligations. Likewise, there are no LCRs for the Energy Division to allocate to Sierra, nor is there a need to do so. Sierra manages its own resources that it requires to maintain system reliability. Since Sierra is its own control area operator, there is no need to evaluate Sierra's load share in the CAISO-determined LCR areas or to adjust its share of coincident peak load. Accordingly, Sierra should have no responsibility towards Local RARs and thus no reason to demonstrate compliance with Local RAR by September 30th.

[39] D.06-06-064, *mimeo,* at p. 5 ("Thus, under the current program, LSEs could be resource-adequate on an aggregate or system basis but transmission-constrained local load pockets could still be resource-deficient. It is this problem that Local RAR is intended to resolve.")

[40] Sierra has no transmission constraints in California that interfere with its ability to serve its California customers. *Id.*, at pp. 11-12 ("Questions remain about various aspects of the Local RAR program, including the best way to identify and define load pockets and to quantify the capacity needed within those areas to meet appropriate reliability standards.")

B. CAISO's Import Capacity Allocation Process Is Irrelevant To Sierra.

A related question raised concerns the application of CAISO Tariff § 40.5.2.2 and the seven step process for allocating limited capacity into the CAISO. For the same reasons that Local RARs are irrelevant to Sierra's circumstances, so too are these requirements. Sierra is not within the CAISO and the CAISO Tariff does not apply to Sierra. Sierra does not receive an allocation of CAISO import capacity. This aspect of the Commission's RA program is simply irrelevant to Sierra's circumstances.

C. Sierra's Winter Peaking Status Means Abundant Resources.

Because Sierra's California territory is winter peaking, the Jumbo IOUs have questioned whether Sierra should make monthly filings showing 100% compliance with system RAR and whether the Commission should increase its current planning reserve margin for Sierra (suggesting a 120% planning reserve margin for the winter months).

First, the CAISO has previously asked the Commission to set a higher planning reserve margin which the Commission has rejected.[41] To set a similar requirement on Sierra would be discriminatory under the statute.[42] Second, to do so would require the Commission to set a planning reserve margin either for the entire Sierra system (which it has no jurisdiction to do) or require it to set a special PRM just for the California service territory. Should the Commission require the latter, then it must be willing to impose and new set of costs on the California ratepayers for the extra resources and regulatory costs imposed by a California-only RA requirement. Irrespective of whether there is any merit to the suggestion from a reliability perspective (a point Sierra rejects), a new requirement on the California fraction of its service

[41] *See*, D.06-12-037, pages 9-10.

[42] Pub. Util. Code § 380(e) ("The commission shall implement and enforce the resource adequacy requirements established in accordance with this section in a nondiscriminatory manner.")

territory would dilute one of the principal benefits enjoyed by Sierra's California customers – namely their lower electricity rates than those of comparable customers in the Jumbo IOU service territories. But most importantly, there is no justifiable need from any perspective for imposing additional reserve margins because the California fraction of Sierra's service territory is winter peaking.

Similarly, there is no need for monthly filings that show 100% compliance with system RAR. As demonstrated above, the Sierra system is stable on both the load and resources sides and under the IRP process overseen by the PUCN, Sierra is increasingly self-sufficient. The system is not, and the California service territory is not, experiencing either rapid load growth, retiring of significant generating capacity, or exposure to load migration. Moreover, the load diversity inherent in Sierra's system means there are abundant reserves to serve its winter peaking California loads while the balance of its system in Nevada experiences lower loads. Accordingly, there is no need for monthly compliance filings.

D. Liquidated Damages Contracts Do Not Present Resource Counting Issues For Sierra

The Jumbo IOUs have also asked a series of questions about pre-October 27, 2005 liquidated damages ("LD") contracts, suggesting that the Commission's RA counting rules as they pertain to LD contracts, should apply to qualify resources to meet Sierra's loads. Again, this concern is a non-sequitur for Sierra.

First, there is absolutely no need to be concerned about LD contracts in the context of Sierra's operation. The issue of LD contracts arose in the context of how to count intra-CAISO control area "Firm LD Contracts". This concern has lead to the disqualification of certain kinds of LD contracts on a phased basis. *This concern is irrelevant because Sierra is not in the CAISO control area.* As its own control area operator, Sierra does not have the type of concern about

resource counting that drove CAISO's concerns about LD contracts without explicit unit identification being committed multiple times. Moreover, the LD contracts pursuant to which Sierra purchases resources are import contracts that, because they are imports to Sierra's control area, must be backed up by reserves under the rules applicable to inter-control area exchanges. Accordingly, the Commission can dismiss as irrelevant So, these contracts do not raise the issues of double counting and deliverability that in-CAISO area LD contracts have.

VII. Sierra's Comprehensive Integrated Resource Plan Process Satisfies The Objectives Of Public Utilities Code Section 380 And Is Functionally Equivalent To The Commission's RA Program

The California RA program and Sierra's comprehensive IRP process differ in their details, but the objectives of the two programs are the same: facilitating development of new, economic generation resources and ensuring sufficient resources to meet peak load in Sierra's service territory at reasonable cost to its ratepayers. Through its use of the IRP process, Sierra already accomplishes the objectives mandated by Section 380.

A. Sierra's Existing Process Assures Resource Adequacy Generally

This submission demonstrates that the Sierra's IRP is the functional equivalent to what the Commission's RA process is intended to yield pursuant to California Public Utilities Code Section 380. The Commission should rely upon Sierra's existing planning process, as overseen by the PUCN, to ensure that Sierra is resource adequate. Accordingly, and as it has done before, the Commission should defer to Sierra's procurement of power sufficient to guarantee resource adequacy under the PUCN's regulatory oversight much as it now does for procurement

generally, and avoid the added expense and inefficiencies that would result from imposing a separate and duplicative set of California-only RA requirements on Sierra.[43]

Imposing a separate, possibly conflicting and likely duplicative, set of California-only RA policies on Sierra, on top of the supply sufficiency requirements that are a fundamental element of its IRP process in Nevada, is unnecessary and counterproductive. Such duplication would do nothing to enhance reliability, would instead undermine both the objectives of Section 380 and Sierra's longstanding success at providing consistently reliable service to its integrated service territory at reasonable rates. Sierra is already developing substantial new generation to serve the integrated load in its Nevada and California service territories, including the 744 MWs of generating capacity additions in June 2008. This development occurs through the existing IRP process. Nor would a California-only RA requirement contribute to the Commission's other policy underpinning its RA requirements, that of making generation capacity "available to the CAISO when and where it is needed for reliable transmission grid operations" for the simple reason that Sierra is not located in the CAISO.[44]

Rather than ensuring the equitable allocation of costs of new generation, any duplicative RA requirement would increase the costs of resource adequacy for both California and Nevada customers due to the separate, possibly redundant and likely conflicting rules.[45] Sierra would have tremendous difficulty in jointly planning for the integrated Nevada and California service territories if it had to comply with two different sets of requirements, since none of Sierra's

[43] In D.04-02-044 the Commission exempted Sierra from the requirement of Pub. Util. Code § 454.5(a) to file a resource procurement plan in recognition of the comprehensive resource planning processes it undertakes in Nevada and that imposition of such a requirement would impose additional, unnecessary costs on Sierra's customers.

[44] D.06-06-064, at 4.

[45] Traditionally, Sierra avoids allocation of costs solely to its 46,000 California customers for programs imposed by California Law. It has been able to do so, in part, because it operates its system as an integrated whole and because the CPUC has thoughtfully deferred to the PUCN on many areas that drive costs. However, if a significant new cost driver was imposed in the regulatory context, principles of cost causation may necessitate some differentiation between customers based upon location.

Nevada generation and transmission resources are allocated to one state or the other. If forced to operate under two separate planning criteria, it would be exceedingly difficult (if not impossible) to determine how to functionally allocate resources and their attendant costs between the two territories.

B. Sierra's Existing IRP Process Meets The Specific Requirements of Section 380

By deferring to Sierra's comprehensive IRP process, the Commission will achieve all three of the objectives mandated by Section 380(b):

(1) Facilitate development of needed new generation: Sierra's comprehensive IRP process already accomplishes this objective. Through the IRP process, Sierra has proposed, and the PUCN has approved, Sierra's acquisition of significant *new* generation. Two of the 14 Amendments to Sierra's 2004 IRP involved construction of significant new generation capacity to be owned by Sierra, and six of the 14 Amendments involved long-term agreements for Sierra's purchase of firm power supplies from generating facilities to be developed on the basis of the power purchase agreements.

(2) Equitably allocate costs of new generation: Through the IRP process and various ratemaking proceedings before the PUCN and the Commission, both state commissions have approved rates that equitably allocate costs of new generation and new power purchase agreements among Sierra's various customer classes in both service territories.

(3) Minimize enforcement requirements and costs: By deferring to Sierra's established, well-functioning, and comprehensive IRP process, the Commission will minimize the enforcement requirements and costs of ensuring resource adequacy borne by Sierra's customers in both Nevada and California. Sierra's IRP process has permitted it to use a competitive procurement process to obtain new power supplies to serve its integrated service territory. Through its competitive procurement process, Sierra has procured energy for its

California customers at an overall price that is lower than the prices seen for power delivered elsewhere in California. Because Sierra secures capacity and energy for its California customers as part of its integrated procurement program as overseen by the PUCN, Sierra has been able to bring tangible benefit to its California customers by keeping rates down.

VIII. The Commission Should Approve Sierra's Proposed Form of Resource Adequacy Filing

Sierra has presented substantial evidence herein for why the implementation details for the CPUC's CAISO-based RA policy are unnecessary or irrelevant for assuring Sierra's California customers have reliable power. So, what does Sierra propose in its place? As described above and in its initial filing on May 18, 2007, Sierra proposes that an annual Advice Letter filing provide all the information needed for the CPUC to determine compliance with Section 380 and Sierra's resource adequacy.[46] By the Annual filing, Sierra show that:

1. Sierra meets the applicable WECC planning and reliability standards;
2. Resources are sufficient to meet forecasted California winter peak loads and system-wide summer peak loads with a 15% planning reserve margin;
3. Sierra has available transmission capacity to deliver energy to California customers;
4. Sierra is taking the necessary steps to meet forecasted loads.

In particular, the Annual RA AL submission would reference Sierra's most recent IRP or Resource Plan every three years, together with its many components that explain how it is meeting current and forecasted load 20 years into the future. At the heart of the IRP is Sierra's L&R Table for its Preferred Plan. Sierra's annual RA AL submission to the CPUC will include the most recent L&R Table to support its showing. In addition, Sierra will provide an appropriate reference to its annual Energy Supply Plan update in the annual RA AL. The Energy

[46] Pub. Util. Code § 380(f).

Supply Plan contains the current load forecast and the latest resources serving that load. These filings will describe Sierra's compliance with the applicable WECC reliability standards, as those requirements continue to evolve. And, of course, the narrative of the annual RA AL filing will describe to the Commission how the information provided in the IRP, Energy Supply Plan or other documentation meets the statutory requirements of Section 380. The RA AL filing process would be consistent with GO 96-B and submitted as a Compliance Filing pursuant to Energy Industry Rule 9. This will provide the Commission with all the information it will need to verify Sierra's continuing resource adequacy.

IX. Conclusion

Sierra urges the Commission to avoid going down the path of simply requiring Sierra to meet the same RAR implementation details that were created over the last three years for the California-only LSEs located within the CAISO. Imposition of a cloned RA program for Sierra would nullify many of the benefits Sierra's 46,000 California customers receive through its integrated resource planning, dispatch and service currently overseen by the PUCN. It would likely lead to rate increases without providing any material improvement in the current level of system reliability. It could also lead to unnecessary and easily avoidable jurisdictional conflicts with the PUCN.

Under Nevada law and PUCN regulations, the PUCN uses the Nevada IRP process to comprehensively review Sierra's energy procurement plans to ensure it has adequate resources to serve both its Nevada and California customers reliably. While the Nevada IRP process may differ in some details from the existing RA process the California-only utilities follow, the Nevada IRP and the California RAR are functionally equivalent and the former meets the fundamental objectives of Section 380: namely development of needed new generation, equitable allocation of those costs, and minimal enforcement requirements and costs. Accordingly, Sierra

urges the Commission to avoid needless complexity and implementation costs and instead find that Sierra may use the existing IRP process under PUCN oversight to fulfill the RA requirement imposed by Section 380. Thus, deferral to Sierra's IRP process is appropriate under Section 380, and is a productive step toward achieving the goals of the Commission's RA Program in an efficient and effective manner.

Dated: September 10, 2007

Respectfully submitted,

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Attachment A

Figures S-2 and S-4

Sierra Pacific Power Company's 2007
Integrated Resource Plan
(See Footnote 20)

FIGURE S-2

COMPARISON OF ANNUAL ENERGY (GWH) AND SYSTEM PEAKS (MW) UNDER THE LOW, BASE, AND HIGH FORECASTS SCENARIOS AND DSM IMPACTS

	Low Case			Base Case			High Case			DSM	
Year	Energy	Summer Peak	Winter Peak	Energy	Summer Peak	Winter Peak	Energy	Summer Peak	Winter Peak	Energy	Summer Peak
2007	9,199	1,640	1,333	9,241	1,647	1,339	9,312	1,657	1,349	56	9
2008	9,063	1,630	1,316	9,121	1,641	1,325	9,402	1,679	1,360	106	15
2009	9,296	1,671	1,350	9,371	1,685	1,361	9,844	1,750	1,420	156	22
2010	9,390	1,694	1,364	9,483	1,712	1,378	10,011	1,786	1,445	206	29
2011	9,409	1,707	1,369	9,540	1,731	1,389	10,105	1,814	1,462	255	35
2012	9,561	1,733	1,388	9,711	1,760	1,409	10,317	1,851	1,489	305	42
2013	9,669	1,750	1,407	9,838	1,782	1,432	10,482	1,882	1,517	349	57
2014	9,775	1,771	1,423	9,984	1,809	1,454	10,850	1,939	1,566	394	64
2015	9,891	1,804	1,441	10,121	1,846	1,474	11,029	1,985	1,593	438	61
2016	10,039	1,827	1,457	10,290	1,875	1,494	11,244	2,024	1,620	482	67
2017	10,108	1,828	1,471	10,401	1,882	1,514	11,398	2,040	1,646	526	92
2018	10,222	1,856	1,487	10,536	1,914	1,533	11,601	2,085	1,675	570	92
2019	10,336	1,876	1,504	10,672	1,939	1,553	11,944	2,139	1,721	614	99
2020	10,464	1,911	1,521	10,845	1,982	1,576	12,170	2,192	1,752	649	90
2021	10,556	1,933	1,536	10,959	2,010	1,595	12,330	2,231	1,779	682	95
2022	10,672	1,954	1,552	11,098	2,035	1,614	12,541	2,270	1,808	717	100
2023	10,764	1,944	1,564	11,235	2,032	1,633	12,731	2,278	1,836	752	132
2024	10,906	1,973	1,580	11,402	2,067	1,652	13,138	2,346	1,884	787	127
2025	10,989	1,992	1,599	11,508	2,090	1,675	13,293	2,381	1,914	823	133
2026	11,073	2,028	1,611	11,637	2,135	1,694	13,499	2,440	1,944	858	119
2027	11,174	2,046	1,622	11,763	2,158	1,708	13,681	2,475	1,968	892	124

Figure S-4

2007 RESOURCE PLAN
SIERRA PACIFIC POWER COMPANY
2008-2027 Preferred Plan (Expansion Plan 3) Base Load Case

	Description	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	SYSTEM PEAK LOAD FORECAST	1,641	1,685	1,712	1,731	1,760	1,782	1,809	1,846	1,875	1,882	1,914	1,939	1,982	2,010	2,035	2,032	2,067	2,090	2,135	2,158
	Planning Reserve Requirement (MW)	246	253	257	260	264	267	271	277	281	282	287	291	297	302	305	305	310	314	320	324
	Planning Reserve Requirement (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
	REQUIRED RESOURCES	1,887	1,938	1,969	1,991	2,024	2,049	2,080	2,123	2,156	2,164	2,201	2,230	2,279	2,312	2,340	2,337	2,377	2,404	2,455	2,482
	RESOURCES (Itemized)																				
	Existing Internal Generation Facilities (Retire Date, 12/31/xx)																				
	Clark Mtn. G.T. 1, 2 (2011 & 2013)	20	20	20	20	10	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Clark Mountain C.T. 3, 4 (2024)	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	-	-	-
	Diesels (1)	21	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
	Ft. Churchill 1 (2018)	113	113	113	113	113	113	113	113	113	113	113	-	-	-	-	-	-	-	-	-
	Ft. Churchill 2 (2021)	113	113	113	113	113	113	113	113	113	113	113	113	113	113	-	-	-	-	-	-
	Tracy 1 (2013)	53	53	53	53	53	53	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Tracy 2 (2015)	83	83	83	83	83	83	83	83	-	-	-	-	-	-	-	-	-	-	-	-
	Tracy 3 (2024)	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	-	-	-
	Tracy 4, 5 (Piñon Pine) (2031)	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104
	Valmy 1 (2021)	127	127	127	127	127	127	127	127	127	127	127	127	127	127	-	-	-	-	-	-
	Valmy 2 (2025)	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	-	-
	Winnemucca G.T.	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
	Total Existing Generation	1,023	1,035	1,035	1,035	1,025	1,025	962	962	879	879	879	766	766	766	526	526	526	286	152	152
	Planned Internal Generation Facilities																				
	Tracy 541MW 2x2x1 CC (2008)	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541
	Newmont Coal Plant (2008)	203	203	203	203	203	203	203	203	203	203	203	203	203	203	203	-	-	-	-	-
	CC19 (2019)	-	-	-	-	-	-	-	-	-	-	-	541	541	541	541	541	541	541	541	541
	CC24 (2024)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	541	541	541	541
		744	744	744	744	744	744	744	744	744	744	744	1,285	1,285	1,285	1,285	1,082	1,623	1,623	1,623	1,623
	Planned Generation Facilities Requiring Import Rights																				
IMP	Ely Coal Unit #1	-	-	-	-	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
IMP	Ely Coal Unit #2	-	-	-	-	-	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
		-	-	-	-	150	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
	Total Planned Generation	744	744	744	744	894	1,044	1,044	1,044	1,044	1,044	1,044	1,585	1,585	1,585	1,585	1,382	1,923	1,923	1,923	1,923
	TOTAL GENERATION	1,767	1,779	1,779	1,779	1,919	2,069	2,006	2,006	1,923	1,923	1,923	2,351	2,351	2,351	2,111	1,908	2,449	2,209	2,075	2,075
	Existing Purchases:																				
	Qualifying Facilities	105	105	105	105	105	105	105	104	104	103	91	89	81	81	71	35	35	35	20	20
	Contracts (Internal)																				
	Naniwa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Barrick	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Contracts (Internal)	113	105	105	105	105	105	105	104	104	103	91	89	81	81	71	35	35	35	20	20
	Contracts (External)																				
IMP	PacifiCorp	75	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IMP	Solargenix	-	-	-	-	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	Total Contracts (External)	75	-	-	-	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	Total Existing Purchases	188	105	105	105	116	116	116	115	115	114	101	100	92	92	81	45	45	45	31	31
	Planned Purchases: (Internal)																				
	Future Unspecified Renewables (Non-Solar)	-	-	-	8	12	35	36	56	58	60	66	74	83	88	96	120	127	132	143	158
	Future Unspecified Renewables (Solar)	-	-	-	8	8	12	13	16	17	18	18	19	19	20	20	21	22	22	23	23
	Hot Sulphur Springs	-	-	27	27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ORNI 3	7	7	7	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ORNI 7	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	ORNI 9	7	7	7	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ORNI 14	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	ORNI 15	-	-	14	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ORNI 16	-	-	14	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Saltwells	-	-	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Stillwater	-	-	8	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Faulkner 1	-	-	19	19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Fleish	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	Verdi	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	Washoe	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	Beowawe	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
	Total Planned Purchases	57	57	142	158	62	89	91	114	117	120	126	135	144	150	158	183	191	196	208	223
	TOTAL GROSS PURCHASES	244	161	247	263	178	205	207	229	232	234	228	235	236	242	240	229	237	242	239	254
	AVAILABLE RESOURCES	2,011	1,940	2,026	2,042	2,097	2,274	2,213	2,235	2,155	2,157	2,151	2,586	2,587	2,593	2,351	2,137	2,686	2,451	2,314	2,329
IMP	OPEN POSITION	-	-	-	-	-	-	-	-	1	7	50	-	-	-	-	200	-	-	141	153
	TRANSMISSION																				
	NETWORK COMMITMENTS:																				
	Barrick (2)	57	34	34	34	34	34	31	30	30	24	24	24	24	24	24	24	24	24	24	24
	TDPUD (forecast from TDPUD) (3)	36	37	38	38	39	40	41	41	42	43	44	45	46	47	48	48	49	50	51	52
	City of Fallon (3)	19	20	20	20	21	21	22	23	23	24	25	26	26	27	28	29	30	31	31	32
	Total Network Commitment	112	91	91	92	93	95	94	94	95	91	92	94	96	98	100	100	102	104	106	108
	PRE-ORDER 888 TRANSMISSION COMMITMENTS:																				
	Mt. Wheeler Total (PacifiCorp Intertie & IPP Intertie) (4)	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
	BPA for Wells and Harney (5)	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
	Total Pre-Order 888 Transmission Commitments	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181
	Total Network & 888 Transmission Commitments	293	272	272	273	274	276	275	275	276	272	273	275	277	279	281	281	283	285	287	289
	TRANSMISSION																				
	System Import Transmission Capacity (6)	1,000	1,000	1,000	1,000	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300
	Import Capacity Requirement for Native Load	75	-	-	-	161	311	311	311	312	318	361	311	311	311	311	511	311	311	452	463
IMP	Import for Renewable Wind Resources	-	150	150	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350
Σ IMP	**Total Import Requirement for Native Load**	**75**	**150**	**150**	**350**	**511**	**661**	**661**	**661**	**662**	**668**	**711**	**661**	**661**	**661**	**661**	**861**	**661**	**661**	**802**	**813**
	Total Network & Transmission Commitments	293	272	272	273	274	276	275	275	276	272	273	275	277	279	281	281	283	285	287	289
	Transmission Reliability (TRM/CBM) (7)	183	185	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183
	Estimated Available Transmission Capacity Based on All Native Load Generating Units Operating (8)	449	393	394	194	331	180	180	181	178	177	132	181	179	177	175	(26)	173	171	27	14

1. Unavailability of the Kings Beach diesels, at least one of the Battle Mt. diesels and the Portolla 6 MW diesels reduces the "Diesels" MW output to 21 MW prior to 2009. Kings Beach replacement diesels (12 MW) increases the value to 33 MW in 2009.
2. Barrick's pro-rata allocation with Sierra Native Load Provider purchasing output from the Western 102.
3. Truckee Donner Public Utility District (TDPUD) and the City of Fallon as a Network Customers have rights to import their full load and losses. These values are based on their forecasted loads.
4. Mt Wheeler includes 31 MW for the City and 40 MW for Quadra Mine.
5. BPA (Harney, Wells - Maggie Creek & Carlin) service not to exceed 110 MW combined per General Transfer Agreement.
6. Maximum import capacity based on optimal operating conditions.
7. The values shown are just for the reserve sharing assistance of Transmission Reliability Margin (TRM) and are based on current load projections, projected firm import usage and projected generation resources. No Capacity Benefit Margin (CBM) is set aside in this table. Both TRM and CBM will be updated as industry standards are developed and implemented and as pertinent information is updated. For years 2013 and beyond, the 2012 value was used. These are forecasted values that will be updated in the future.
8. Estimates are based on summer peak conditions only. ATC will vary by month.

Attachment B

Draft 2008
Sierra Pacific Power Company
Annual Resource Adequacy Advice Letter

[date]

VIA OVERNIGHT MAIL

ADVICE LETTER NO. xxx-E
(U 903-E)

California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102-3298

SUBJECT: 2008 Annual Resource Adequacy Requirement ("ARAR") Compliance Filing.

PURPOSE

Sierra Pacific Power Company ("Sierra") hereby makes its Annual Resource Adequacy Requirement ("ARAR") Compliance Filing for the 2008 calendar year in compliance with Public Utilities Code Section 380 and D.07-XX-XXX implementing the ARAR for Sierra.

BACKGROUND

In D.07-XX-XXX ("Decision") the Commission adopted certain modifications to its existing Resource Adequacy Requirement ("RAR") program to reflect the particular circumstances of various Small and Multi-Jurisdictional Utilities ("SMJUs") for purposes of implementing Public Utilities Code Section 380. The Decision acknowledges the existing and extensive Integrated Resource Planning ("IRP") Sierra complies with pursuant to Nevada law, subject to the oversight of the Public Utilities Commission of Nevada ("PUCN"). Further, the Decision recognizes that the existing RAR program was designed for public utilities located within the California Independent System Operator ("CAISO") control area, and because Sierra is outside the CAISO, elements of the existing RA program are unnecessary and irrelevant in Sierra's circumstances. Furthermore, the Commission recognized in the Decision that imposition of a California-only RAR policy on Sierra could result in unintended conflicting regulatory requirements and otherwise avoidable regulatory costs. Accordingly, the Decision adopted Sierra's recommendation that the Commission establish Sierra's ongoing compliance with Section 380 through submission and review of data presented in the IRP to the PUCN.

This AL contains information from Sierra's current IRP-related materials that supports a finding that the utility complies with Section 380. Publicly available information on the current IRP and Energy Supply Plan can be found at http://www.sierrapacificresources.com/ftp/ir/ under the "SPPC Resource Plan" tab.

This ARAR contains the following attachments:

1) Current information regarding system load forecast (MWh and MW) (Figure S-2 from the IRP Summary);

2) The current Load and Resources ("L&R") Table (Figure S-4 from the IRP Summary) indicating system load, the 15% planning reserve margin, existing resources, and import capability sufficient to assure resource adequacy; and

3) [Other information in narrative form regarding current estimate of California load, sufficiency of resources to meet the California winter peak loads, and sufficiency of Sierra's transmission system to deliver to California loads.]

EFFECTIVE DATE

Sierra asks that this AL be made effective on [date]. The ARAR Compliance Filing is subject to Energy Division review under GO 96-B, Energy Industry Rule 9.

PROTESTS

This Compliance Filing is not subject to protest. See GO 96-B, Energy Industry Rule 9.

NOTICE

In accordance with Section 4 of GO 96-B, copies of this advice letter will be sent to the parties shown on the attached list.

If additional information is required, please contact [name] and [phone] or [email]

Sincerely,

[signature block]

Attachments

Certificate of Service

I hereby certify that I have this day served a copy of "Supplemental Proposal Of Sierra Pacific Power Company (U 903 E) With Respect To Resource Adequacy Requirements For Small And Multi-Jurisdictional LSEs" on all known parties to R.05-12-013 by transmitting an e-mail message with the document attached to each party named in the official service list. Parties without e-mail addresses were mailed a properly addressed copy by first-class mail with postage prepaid.

Executed on September 10, 2007 at Sacramento, California

/s/

Eric Janssen

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