

Appendix P4

**Response to NTCAA February 14
Comments and Supporting Documents**

North Tahoe Citizen Action Alliance

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**Subject: Technical Comments on the Draft EIS/EIS/EIR
CalPeco/Liberty Utilities 625 and 650 Electrical Line Upgrade**

Dear Lead Agencies:

The following comments on the Draft EIR/EIS/EIS (DEIR) are being submitted at this time due to the late release of the technical reports designed to accompany the Draft (January 3, 2014) just prior to the closing of the public comment period on January 7, 2014. NTCAA first requested these reports about a year ago on January 8, 2013.

After review and consultation with technical experts NTCAA understands the full loop upgrade concept originated in 1996 as an answer to reliable capacity concerns raised by load growth projections that never actually occurred. Public policies, efficient technology improvements, and market decisions aimed at reducing demand for electricity have succeeded over the last fifteen years, rendering the full loop concept as proposed in the DEIR technically unsupportable. The Lake Tahoe Basin does not have to be environmentally degraded from reconstruction of the 625 line today. NTCAA seeks only the facts and a process that honors reason, engineering, and economics.

The long delay in providing the technical support for the proposed project suggests the Project Proponent is less than open and transparent, raising questions about trust of the integrity of the technical data and consistency with utility engineering standards. NTCAA was granted “party status” on February 3, 2014 by the presiding Administrative Law Judge for the California Public

Utilities Commission in the proceeding for Liberty Utilities' Application for a Permit to Construct.

Liberty Utilities should therefore provide the evidence to substantiate their study's assumptions as requested in the **Data Request** section below.

The Technical Reports released January 3, 2014 include for the record:

- 1) The 1996 North Tahoe Capacity Plan, prepared by Sierra Pacific Power, (referred to as 1996 Plan)
- 2) The North Tahoe System Capacity Plan Validation Report, August 2011, by ZGlobal (referred to as the ZGlobal Report).
- 3) The North Lake Tahoe Electric Transmission System Upgrade Scoping Document, September 2011 by TriSage Consulting (referred to as the TriSage Report)

These reports, according to the DEIR, provide the technical foundation to justify the proposed project's purpose and need, to define the alternatives analysis, and identify the assumed configuration (full loop at 120kV) as the necessary basis of all discussion of environmental impacts. The DEIR reads, *"The original planning assumptions, project scope, and schedule established by Sierra Pacific were based on a 1996 study of the system needs."* (DEIR 2.1.5, p.2)

There is further evidence in the technical reports that the Project Proponent was predisposed to the full loop at 120kV, the only option studied in the 1996 Capacity Plan, to resolve reliable capacity problems caused by Report's net load growth projections. This bias resulted in the four action alternatives based on the same technical configuration while denying any consideration of viable alternatives (partial loops) that could postpone the 625 line reconstruction for 20-30 years and avoid immediate environmental degradation in the Lake Tahoe Basin.

The most controversial component of the full loop configuration is the proposed relocation of the 625 line in the Lake Tahoe Basin (connecting Tahoe City and Kings Beach). This section of line accounts for the majority of the proposed project's environmental damage to the Lake Tahoe Basin, including removal of 25,000 trees (p. ES-11), the movement of several thousand truckloads disrupting habitat, and the "largest tree removal and road building project" in the Tahoe Basin's modern history (conversation with Rodman, USFS). This appears to be especially wasteful because the existing 625 line's conductor is already the largest used in the North Tahoe area (397.5AA whether for 60kV or 120kV) and does NOT ever overload in any of the reports relied upon by the DEIR.

There should be a sound technical basis to justify this level of environmental impact upon a federally designated "Outstanding National Resource Water," but the technical reports the DEIR rely on do not provide it.

The Project Loop vs. the North Tahoe System

In the DEIR the 60 kV project-area loop connects four substations (Northstar, Kings Beach/Brockway, Tahoe City, and Squaw Valley) and constitutes only a portion of the North Tahoe System. The DEIR shows in Table 3-1 (p. 3-10), Coincident Peak Demand from 2007-2012 with peak loads from 86.7 MVA to 88.4 MVA respectively, for all substations connected to the North Tahoe System, **including substations outside the project-area loop**; such as, Tahoe Donner Public Utility District's (TDPUD) Martis Valley, TDPUD Truckee, Glenshire, Truckee 60kV, and other lines. To clarify and avoid confusing loads outside the project-area loop (the specific subject of the DEIR) we refer to the proposed project upgrade loop as the **Resort-Tahoe Loop**.

The following peak loads for each substation are reprinted from the 1996 Capacity Plan (Attachment 4) and the 2011 ZGlobal Report (p. 11):

<u>Substation</u>	<u>1996 Peak load</u>	<u>2010 Peak load</u>	<u>Change</u>
Resort-Tahoe Loop			
Squaw Valley	17.6	11.5	-35%
Tahoe City	20.2	26.1	+29%
KB/Brockway	16.4	14.9	-9%
Northstar	7.3	8.6	+18%
Resort-Tahoe Loop Peak Load (MW)	61.5	61.1	-0.7%
Balance of North Tahoe System			
TDPUD Martis	5.5	8.6	+56%
Truckee 60kV bus	6.0	3.8	
TDPUD Truckee		9.6	+123%
Glenshire	3.3	2.8	-15%
Outside the Loop Peak Load (MW)	14.8	24.8	+68%
North Tahoe System Peak Loads (MW)	76.3	85.9	+13%

These actual peak loads by substation demonstrate the need to distinguish the Resort-Tahoe Loop from the entire North Tahoe System. The Resort-Tahoe Loop, containing the 650 and 625 lines, is the primary focus of the N-1 (single contingency) outages examined. The Resort-Tahoe Loop is exclusively targeted in the power flow analyses of loads and overloading, conductor ratings, and voltage drop issues in the technical reports. Substations outside this loop have their own reliability issues related to their transmission and distribution lines, and are not dependent upon the Resort-Tahoe Loop.

As shown above, Liberty Utilities' own data shows the only net load growth since 1996 is outside of the project-area, referred to as the "Balance of the North Tahoe System." The flaw in the framework of using total North Tahoe System loads - conflating all North Tahoe System loads as if they occurred on the Resort-Tahoe Loop - becomes absurd in the event that all future peak load growth occurring outside the loop is used to justify negative environmental impacts of upgrading inside the loop.

Foundation of the Full Resort-Tahoe Loop at 120kV – The 1996 Capacity Plan

The first proposal to upgrade the complete 60kV Resort-Tahoe Loop to operate at 120 kV was presented in the 1996 North Tahoe Capacity Plan by Sierra Pacific Power (now NV Energy). The study's projected load growth drove the concept of a full-loop upgrade as the best configuration for the Resort-Tahoe Loop because loads were projected to grow 54% by 2010. The Report discussed how upgrading the Resort-Tahoe Loop to 120 kV would provide back-up service to Incline Village for an N-1 contingency in Nevada, and would further improve the reliability to NV Energy's Nevada customers if the loop was extended into Incline Village. NV Energy served the entire region in both California and Nevada at that time, so it was a logical framework to plan for Incline Village as well as the North Tahoe System.

Projected Loads

Peak loads of the North Tahoe System in 1996 were about 76 MW of which 61.5 MW occurred in the Resort-Tahoe Loop. Projected load growth in 1996 was assumed at 3% per year, and was spread equally to all substations in the broad bi-state service area. At this rate for the North Tahoe System peak loads were projected to reach 135 MW by 2010, whereas actual system peak loads were only 86 MW. The Report estimated Incline Village loads in 1996 were 23+ MW (p. 6) and were projected to reach 36 MW by 2010. Peak loads were estimated in 2011 at 20.2 MW (ZGlobal Report, p. 42), more of a decline in fourteen years than in the Resort-Tahoe Loop.

The **Resort-Tahoe Loop peak loads were 61.5 MW in 1996** (p. 16 Attachment 4) and projected to be 95 MW by 2010, but again **actual peaks loads were only 61.1 MW in 2010** (ZGlobal Report, p. 12).

The significance of this error in projections is not simply that the 3% annual load growth was inaccurate, but that the projections established a false sense of urgency (lack of adequate capacity) for an immediate solution. The assumed projections caused the full loop at 120kV concept as the only answer to a theoretical capacity problem. Fourteen years later the Resort-Tahoe Loop peak loads actually declined, Incline loads declined, while loads outside the loop increased by 68%.

The 1996 Plan even qualified its full-loop upgrade option by noting two drawbacks, "Large initial investment required. **Slow growth may not warrant it.**" (p. 10) Peak load growth in the Resort-Tahoe Loop wasn't just slow, it never happened. This fact was not only ignored by NV Energy and Liberty, it was concealed by using North Tahoe System aggregate loads. The Resort-Tahoe Loop loads were combined with loads outside the loop to produce deceptive overall loads and misleading the public and decision makers.

Knowledge of actual load data from 1996-2010 should have triggered an entirely different approach to providing reliable capacity by 2010; instead, Sierra Pacific Power (SPP) filed an Application (10-08-024) with the California Public Utilities Commission for a Permit to Construct the full Resort-Tahoe Loop at 120kV without any analysis or reevaluation of factual circumstances.

CPUC Application Transitions to Liberty Utilities

This CPUC Application, dated August 31, 2010, included the proposed project which is the subject of the Proponents Environmental Assessment (PEA) or Alternative 1 in the Draft EIR. That single alternative was slightly modified into three more "action alternatives" which all represent the same full 120 kV loop concept based on an obsolete and flawed 1996 Plan.

For NV Energy to ignore records for fourteen years of actual load data, to ignore the 1996 Plan's technical proviso that "slow growth may not warrant it," to conceal no load growth at substations on the loop targeted for upgrade, and to fail to conduct an unbiased technical reevaluation of the North Tahoe System prior to submitting their 2010 CPUC Application raises serious questions.

There has been an unwarranted predisposition to support the 1996 full loop upgrade concept regardless of technical facts. The DEIR is infected deeply with bias regarding alternatives, the analysis of alternatives eliminated or ignored, and the assumed imposition of negative environmental impacts to the Lake Tahoe Basin as a public utility necessity.

NV Energy was at this time (2010) negotiating with Liberty Utilities for the sale of their California service area. This may indicate there were other conditions, promises, or obligations of the sale that influenced why Liberty retained the 1996 Plan's concept, resumed the CPUC Application process, and retained the PEA as the base environmental document. Full disclosure of all conditions related to the eventual sale to Liberty should be released to the public; for example, the “dedication” of half of the power from the Kings Beach Generating Plant to NV Energy (ZGlobal Report, p. 8).

Data Request

NTCAA requests the following information to allow our technical experts to complete their technical analysis:

- 1) The actual recorded loads by the hour for each substation within the Resort-Tahoe Loop for the two weeks surrounding peak load, which was identified as occurring on December 30, 2012, and for each year from 2007 to 2012.
- 2) The actual recorded loads by the hour for each distribution circuit to the four ski resorts' major loads (chairlifts, gondolas, snow making, general services, etc.). Documentation identifying interruptible loads and coincident versus non-coincident peak loads at the four ski resorts in the event of a single (N-1) or double (N-2) contingency condition.
- 3) Normal and emergency 60kV, 120kV, and 14kV conductor ratings as a function of ambient temperatures and winds (including any changes in such ratings since 1990) that were used in the 1996 Plan and ZGlobal Report power flow analyses.
- 4) Normal and emergency overload percentages used in the 1996 Plan and the ZGlobal Report power flow analyses.
- 5) All documents relating to the "harmonic resonance" problems relied on by Sierra Pacific, CalPeco/Liberty, ZGlobal, TriSage, and/or Ascent Environmental. The Reports imply switchable shunt capacitors on the 60kV system may cause "harmonic resonance" problems with variable speed motor loads at the ski resorts, but there is no evidence supporting this, or any assessment at what increments and locations switchable shunt capacitors would work. The Reports do show some use of shunt capacitors in their power flow analyses.
- 6) Records of all 60kV and 120kV outages since 2000, with specific location of the outage, its duration, and the number of customers impacted.
- 7) All documents related to the technical justification and economic cost of upgrading the Northstar substation service from the present 1-line tap to a 2-line loop or fold. This includes

any assessment of adding motor-operated disconnects at the tap point on both the Truckee and Kings Beach legs of the 650 line and a cost comparison to the fold.

8) All documents addressing and/or comparing the costs of “line clearing” (vegetation management) for the existing 625 line and the preferred alternative rerouting for the 625 line.

9) All reports and studies of the peak load event that occurred on December 30, 2012.

10) A chart entitled “2012 Peak that Exceeded Capacity “, plots “LU CA Demand (MW)” up to 140 MW in late December, and has been used repeatedly in public presentations. This appears to be the total Liberty system loads, including South Lake Tahoe loads served independently from Truckee sources. This is not just loads outside the Resort-Tahoe Loop, but outside the greater North Tahoe area itself.

Provide a similar hourly load chart, for the same time period, for the loads served in the Resort-Tahoe Loop substations.

11) All operating procedures for the North Tahoe System, including Incline Village loads for NV Energy/SPP concerning line loading and/or voltage problems in place since the 1996 Plan.

12) All documents dealing with the transfer of loads between the North Tahoe System and its connected distribution systems (e.g. between Northstar and Truckee, Tahoe City and the South Tahoe area) as well as NV Energy's system (e.g. between King's Beach and Incline Village).

13) All documents related to and detailing the Vegetation Management Plan since approval by the CPUC (December 2012) for the \$2.5 million per year of vegetation management funding.

14) All documents relating to, and including, each draft of the ZGlobal and TriSage Reports.

New Loads vs. Net Load Growth

Given the technical reality of no net load growth on the Resort-Tahoe Loop since 1996 and no evidence this is an anomaly, there should be an analysis to determine the cause and factors contributing to declining loads, and will this continue. Circumstances and technology in 2014 have changed from twenty years ago. Today there are accurate load records showing reduction in loads and the obvious success of energy efficiency technologies, stricter building codes, and regulatory practices to encourage conservation, efficiency, and alternatives.

There is evidence of new building permits resulting in new loads over the last fourteen years, yet the combination of efficient lighting, appliances, conversion to cheaper natural gas, LED bulbs for Christmas lights (a coincident peak load), among others, is offsetting new loads in the Resort Tahoe Loop and in Incline Village. An analysis must be able to explain the facts which have rendered the 1996 Plan technically inaccurate, obsolete, and incapable of supporting its full-loop concept.

ZGlobal's Final Report "updating" the 1996 Capacity Plan

ZGlobal was hired by Liberty Utilities in 2011 to "validate" Sierra Pacific's full loop upgrade to 120 kV plan from 15 years earlier, not as an independent expert to assess applicability to existing conditions. ZGlobal's Final Report, dated August 2011, was narrowed by following their initial directive, *"...to limit their review to the empirical electrical data without inclusion of operating constraints. This was initiated to facilitate the tight time frame with the NEPA and CEQA project filing."* (p. 4)

ZGlobal's analysis shows incremental steps can be taken to improve reliability, such as the immediate reconductoring of the 650 line to the Northstar tap. But further improvements are tied to the demonstration of net load growth without an immediate commitment to rebuilding and operating the full loop at 120kV. In fact, this time sequence significantly postpones upgrade of the 625 line and the resulting degradation to the Lake Tahoe Basin.

The analysis ran the worst single contingency scenarios, loss of the 132 line and loss of the 650 line, and arrived at two Scenarios. ZGlobal generated an "Upgrade Sequence" table for Scenario 1, wherein the **625 line upgrade in the Tahoe Basin upgrade was scheduled as loads reached 113 MW projected to occur in 2037** (p. 37). Scenario 2 scheduled the 625 line upgrade in 2032 when loads reach 107 MW (p. 38). The single contingency loss of the 132 line represents N-1 but with the 609 line tripped out also, the result is an N-2 condition; that is, two major transmission lines are lost at the same time. The DEIS is based on achieving N-1 reliability only.

The ZGlobal Report may have reduced load growth to 1% per year going forward, but that does not cure the load projection error in the 1996 Capacity Plan. It was the excessive net load growth projections that justified the 120kV full loop concept to solve capacity and N-1 conditions. But loads on the Resort-Tahoe Loop actually declined from 1996-2010.

There was no analysis of the factors reducing load growth which rendered the 1996 Capacity Plan inaccurate and outdated, and no distinction between the zero load growth of the Resort-Tahoe Loop and a nearly doubling of load growth outside of the Loop.

Based on assessments by our technical experts there are several technical questions about assumptions in the ZGlobal Report. It appears to be unclear as to the ambient conditions

(temperature and wind) associated with the conductor ratings. There are significant differences between summer or winter ratings, the allowed temperature rise assumed in the conductor ratings, and the assumed N-1 overload percentages.

There are technical questions regarding the use of switched capacitors for voltage support which ZGlobal suggests may be in conflict (harmonic resonance) with the variable speed motors at the ski resorts. Liberty should have the studies showing what levels and locations switched capacitors can be employed.

The ZGlobal Report proposes a partial loop at 120 kV for the 650 line at the 95 -110 MW peak loads. Today's peak loads are about 61 MW for the Resort-Tahoe Loop. This partial loop sequence opens the door to specific technical thresholds prior to incurring environmental and economic costs of the full Resort-Tahoe Loop at 120 kV, especially the 625 line reconstruction in the Lake Tahoe Basin.

ZGlobal's Time Sequence

One of the most significant findings in ZGlobal's Report is the Upgrade Sequence Table for Scenario 1 and Scenario 2 (Appendix C, P. 37 and Appendix D, P. 38). The only difference between the scenarios is whether the 609 line is reconductored or a Transfer Trip is installed to eliminate the line in the event of an overload (creating an N-2 condition).

At the 2010 system load of 86 MW the sequence is to first reductor the 650 line from Truckee to Northstar, then the second action is reductor from Northstar to Kings Beach, but still operating at 60kV. The third action is the 609 line options, either reductoring or tripping.

The next action occurs at a system load of either 95 MW (if the 609 Trip is installed) or at 110 MW (if the 609 is reductored). The estimated time (based on 1% growth) is either 2021 or 2035 respectively. The action is to install a Partial 120 kV Loop; that is, upgrade only the 650 line for operation at 120 kV.

The full loop upgraded and operated at 120 kV, to be completed when the 625 line in the Tahoe Basin is reconstructed, is not sequenced until loads reach 107 MW (2032) or 113 MW (2037).

ZGlobal's analyses are all using total system loads, including substations not even connected to the Resort-Tahoe Loop. If the Truckee substations are responsible for most of the North Tahoe System's new loads, while the Resort-Tahoe loop experiences only modest or even zero load growth, the 625 line may not require reconstruction for two or three decades.

NV Energy and Incline Village, Homewood, and Future loads

The 1996 Capacity Plan clarifies the importance of this connection to Incline Village:

“...the most promising approach appears to be backing up Incline Substation with additional capacity and 14.4 feeders from Brockway. This would, of course be dependent on the improvements on the North Tahoe loop, and so make the improvements in this plan all the more important. (p. 6)

The 1996 Report explained that only about half of Incline's load of 23+MVA could only be served from Kings Beach and Glenbrook (P.6). The ZGlobal Report uses a 2011 Incline load of 20.2 MW, which indicates over the last fifteen years, Incline Village's loads have also decreased even with new loads.

The ZGlobal Report treats Incline Village emergency back-up as equivalent to a single contingency event, and concludes that adding Incline's 20.2 MW to the current Kings Beach substation during 2011 peak conditions would only result in low voltage conditions in Tahoe City that could be mitigated (p. 42). Increasing loads to 123 MW caused an overload on the 650 line (p. 44), so eventually the capacity to supply Incline Village is critical to any improvement to the 650 line and involves NV Energy as a significant stakeholder. Furthermore, to the extent Incline Village loads may be transferred to Kings Beach, there is the reciprocal scenario in which Brockway loads are transferred to Incline Village. The ZGlobal Report did not assess this potential, or how upgrading the existing 14.4 kV lines from Kings Beach to Incline Village to 60kV could improve reliability for the Resort-Tahoe Loop.

The Kings Beach generating plant is addressed in the ZGlobal Report,

"It should be noted that the use of the Kings Beach diesels is limited to 721 hours per year, with half of these hours being dedicated to NVE. (P. 8)

What exactly is the agreement with NV Energy regarding the use of the Kings Beach diesels? Is NV Energy paying for half of the plant and its maintenance to receive half of the power? Is there a reciprocal agreement with NV Energy to accept loads during N-1 or N-2 conditions in the Resort-Tahoe Loop?

Homewood Mountain Resort

The approved Homewood development was modeled by ZGlobal and assumed a new load of 8MW. But the analysis is inadequate due to assuming the full loop is upgraded at 120kV before the 8 MW increase in load, resulting in no issues (p. 39). This limited analysis fails to incorporate the staged construction of HMR, and that loads would increase gradually over many years, and perhaps never reaching the full 8MW. The analysis fails to assess the partial loop to

Tahoe City operating at 120kV, and what improvements may be necessary to serve HMR under current circumstances (without the full loop) or under a partial 120 kV loop to Tahoe City.

Alternative staging sequence

Depending on the “real” conductor ratings, more accurate load data, some ability to switch capacitors, the alternative staging of system upgrades could be:

- 1) Reconductor the 650 line from Truckee to Northstar. This is the only non-controversial portion of the proposed project that appears to have existing technical support for immediate installation.
- 2) Add motorized disconnects on the Truckee and Kings Beach legs, leaving 3 point tap (no fold). No expensive fold should be installed without technical justification and an analysis of cost and benefits.
- 3) Add switchable shunt capacitors (or Static VAR Compensators) at Tahoe City and/or Kings Beach substations.
- 4) Reconductor the Northstar to Kings Beach 650 line leg at 120 kV but continue to operate at 60kV. This step involves NV Energy participation and financial contribution as a significant beneficiary to eventual operation at 120 kV. Undergrounding the 650 line through the Kingswood East subdivision is another issue to be analyzed for cost and benefits
- 5) Upgrade operation between Truckee and KB to 120kV if warranted by actual load growth.
- 6) Upgrade operation of Squaw Valley to Tahoe City to 120kV. This step could include the relocation of the Tahoe City substation and deserves an analysis of costs and benefits.
- 7) Relocation/rebuilding of the 625 line to complete the 120kV operation of the loop, which could easily be 20-30 years out, depending on net load growth from the current Resort-Tahoe Loop peak load of 61 MW.

Conclusion

What began as a project driven by the urgency to meet projected loads (1996 Capacity Plan) has evolved into one for "reliability and safety" during emergency conditions. With the significant reduction of actual loads from what was projected, and with the partial loop alternatives sequenced to target N-1 conditions, the urgency has lost its technical basis.

The justification for the full loop now presented by Liberty Utilities is "to prevent future problems" if they happen (statement made by Liberty attorney during the CPUC pre-hearing conference February 3, 2014). Improving reliability and safety are general goals for any utility, while the specific actions that obligate ratepayers and result in environmental degradation to the Lake Tahoe Basin must show the technical support.

The DEIR promotes a conceptual plan from 1996 that answers projections of net load growth that never happened. The DEIR is long on fear of outage rhetoric and short on technical support to improve reliability consistent with utility engineering standards, and is therefore inadequate to technically justify the proposed project.

Respectfully submitted,

David McClure

President, North Tahoe Citizen Action Alliance

Responses to NTCAA February 14, 2014 Technical Comments on the Draft EIS/EIS/EIR Calpeco/Liberty Utilities 625/650 Electrical Line Upgrade.

NTCAA Comments Page 1

Paragraph 1: NTCAA explains that comments are submitted late due to the late release of technical reports.

Response: *Comment noted.*

Paragraph 2: NTCAA contends that the full loop upgrade concept was developed in response to load growth concerns that never actually occurred. NTCAA contends that currently, the full loop concept proposed in the DEIR is technically unsupportable.

Response: *the Final EIS/EIS/EIR supports the full loop concept identified as the proposed project in the FEIS/FEIS/FEIR as a reasonable approach based on sound engineering principles. The dates on which phases II and III will be constructed is contingent on future load growth.*

Paragraph 3: NTCAA contends that due to the long delay in providing the technical support for the proposed project suggests the Project Proponent is less than open and transparent.

Response: *Comment noted.*

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Paragraph 4: NTCAA requests that Liberty release technical reports on January 3, 2014. These reports include: 1996 North Tahoe Capacity Plan; North Tahoe System Capacity Plan Validation Report; North Lake Tahoe Electric Transmission System Upgrade Scoping Document.

Response: *These documents were not relied upon for the development of the Draft EIS/EIS/EIR.*

Paragraph 5: NTCAA contends that there is evidence in the technical reports that the Project Proponent was predisposed to construction of the full loop at 120 kV and this bias resulted in the four action alternatives in the environmental document; all denying any consideration of viable partial loop alternatives that could postpone 625 line construction for 20-25 years.

Response: *The timing of the eventual full loop build out is contingent on future load growth.*

Paragraph 6: NTCAA contends that the most controversial component of the full loop configuration is the proposed relocation of 625 Line in the Lake Tahoe Basin, connecting Tahoe City to Kings Beach.

Response: *NTCAA correctly points out that this section of line accounts for the majority of environmental impacts. NTCAA correctly points out that 625 Line's conductor is already the largest used in the North Tahoe area (397.5 AA) and that the reports relied upon by the DEIR do not demonstrate the line is overloaded. However, project objectives as identified on page 2-5 of the Draft EIS/EIS/EIR include: "provide more reliable access to the 625 line for operation and maintenance activities." Ultimately, the timing of construction of the 625 line will be based on future load data..*

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Paragraph 7: NTCAA identifies the project area look as connecting Northstar, Kings Beach/Brockway, Tahoe City, and Squaw Valley substations. NTCAA points out that The DEIR shows coincident peak demand for all substations connected to the larger North Tahoe System, including loads outside the project area. NTCAA refers to the project area as the “Resort-Tahoe Loop” and finds that within the project area, peak loads from 1996 to 2010 dropped .7%. At the same time, peak loads on the remainder of the North Tahoe System increased 68%.

Response: NTCAA has correctly characterized the project area and the fact that the DEIR shows coincident peak demand of the entire North Tahoe System. At this time there is insufficient data to determine how growth outside of the “Project Loop” as defined by NTCAA, would affect the timing of phases II and III.

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Paragraph 8: NTCAA points out the need to distinguish peak loads by Substation to isolate the Resort-Tahoe Loop from the entire North Tahoe System. NTCAA asserts that substations outside the Resort-Tahoe Loop are not dependent upon the Resort Tahoe Loop.

Response: It is not possible to verify NTCAA’s assertion due to the highly technical nature of power flow analyses. Staff held technical discussions with NTCAA’s electrical engineer, the CPUC contracted engineer, and Liberty Utilities engineers who modeled North Tahoe System power flow, but no clear agreement was reached on which substation loads should be included in calculating load with regard to demand trigger thresholds for phases II and II identified in the environmental document.

Paragraph 9: NTCAA asserts that Liberty Utilities’ data shows that the only net load growth since 1996 has occurred outside the project area.

Response: The assertion cannot be evaluated with available data.

Paragraph 10: NTCAA provides a history of the proposal to upgrade the Resort-Tahoe Loop to operate at 120kV, pointing out that the North Tahoe Capacity Plan projected load growth of 54% by 2010. NTCAA further contends the loop was intended to provide power to Incline Village as Sierra Pacific had Nevada customers.

Response: Comment noted. The timing of construction of the full loop concept is contingent on future load growth.

Paragraph 11: NTCAA asserts that peak loads of the North Tahoe System in 1996 were about 76 MW of which 61.5 occurred in the Resort-Tahoe Loop. Project load growth in 1996 was assumed at 3% per year. At this rate, the North Tahoe System total loads were projected to reach 135 MW by 2010, whereas actual system peak loads were only 86 MW.

Response: There is no disagreement with the NTCAA assertion that load levels have declined in some portions of the North Tahoe System. The timing of construction of the full loop concept is contingent on future load growth.

NTCAA Comments Page 5

Paragraph 12: NTCAA asserts that the Resort-Tahoe Peak Loads were 61.5 MW in 1996 and projected to be 95 MW by 2010, but according to the ZGlobal report, peak loads were only 61.1 MW in 2010.

Response: *There is no disagreement with the NTCAA assertion. The timing of construction of the full loop concept is contingent on future load growth.*

Paragraph 13: NTCAA asserts that the assumed projections caused the full loop at 120KV concept as the only answer to a theoretical capacity problem.

Response: *The FEIS/FEIS/FEIR correctly identified the full loop concept as the preferred approach to meet project objectives. The timing of construction of the full loop concept is contingent on future load growth.*

Paragraph 14: NTCAA contends that Liberty concealed the fact that growth in the Resort-Tahoe Loop never happened by using North Tahoe System aggregate loads that were intended to mislead the public and decision makers.

Response: *Comment noted. This allegation cannot be verified with data currently available.*

Paragraph 15 NTCAA contends that actual load data from 1996-2010 should have triggered an entirely different approach to providing reliable capacity by 2010; instead SPP filed a PTC to construct the full Resort-Tahoe Loop.

Response: *Comment noted.*

Paragraph 16: NTCAA contends that for Liberty to ignore 14 years of actual load data and the 1996 Plan's technical proviso that "slow growth may not warrant it", to conceal no load growth at substations on the Resort-Tahoe Loop and failure to conduct an unbiased technical reevaluation prior to submitting their 2010 CPUC Application raise serious questions.

Response: *Comment noted.*

Paragraph 17: NTCAA contends that the DEIR is deeply biased regarding alternatives, the analysis of alternatives eliminated or ignored and the assumed imposition of negative environmental impacts of the Lake Tahoe Basin as a public necessity.

Response: *Comment noted.*

NTCAA Comments Page 6

Paragraph 18: NTCAA notes that at the time of the CPUC application, NV energy was negotiating with Liberty Utilities for the sale of their California service area. NTCAA calls for full disclosure of all conditions related to the sale to Liberty should be released to the public.

Response: *Comment noted.*

Paragraph 19: NTCAA requested the following data:

1. Actual recorded loads with Resort-Tahoe Loop for the two weeks surrounding peak load.
2. The actual recorded loads by hour for each distribution circuit to the for ski resorts' major loads; documentation identifying interruptible loads, and coincident versus non-coincident peak loads.

3. Normal and emergency 60 kV, 120kV and 14kV conductor ratings as a function of ambient temperatures and winds that were used in the 1996 Plan and ZGlobal Report power flow analysis.
4. Normal and emergency overload percentages used in the above cited reports.
5. All documents relating to the “harmonic resonance” problems.
6. Records of all 60kV and 120kV outages since 2000, with specific locations, duration and number of customers impacted.
7. All documents related to the technical justification and economic cost of upgrading the Northstar substation service to a 2-line loop, including assessment of adding motor-operated disconnects at the tap point on both the Truckee and Kings Beach legs and a cost comparison to the fold.
8. All documents addressing and/or comparing the costs of “line clearing” for the existing 625 line and preferred alternative route.
9. All reports and studies of the peak load event that occurred on 12-30-12.
10. A chart entitled “2012 Peak that Exceeded Capacity”, plots “LU CA Demand (MW). Provide a similar hourly load chart, for the same time period, for the loads served in the Resort-Tahoe Loop substations.
11. All operating procedures for the North Tahoe System, including Incline Village loads for NV Energy/SPP concerning line loading and/or voltage problems in place since the 1996 Plan.
12. All documents dealing with the transfer of loads between the North Tahoe System and its connected distribution systems.
13. All documents related to and detailing the Vegetation Management Plan since approval by the CPUC (December ’12) for the 2.5 million per year of vegetation management funding.
14. All documents relating to, and including, each draft of the ZGlobal and TriSage Reports.

Response: *These documents were not relied on by the Draft EIS/EIS/EIR.*

NTCAA Comments page 7

Paragraph 20: NTCAA comments that given the technical reality of no net load growth on the Resort-Tahoe Loop since 1996 and no evidence this is an anomaly, there should be analysis conducted to determine the cause and factors contributing to the declining loads. NTCAA contends that factors such as energy efficiency measures, building codes and other regulatory practices have caused the load declines.

Response: *It is not possible to verify NTCAA’s contention with available data.*

NTCAA Comments page 8

Paragraph 21: There is evidence of new building permits resulting in new loads over the last 14 years, but NTCAA contends that a combination of technology, conversion to natural gas, and other factors have offset the demand caused by new loads in the Resort Tahoe Loop and in Incline Village.

Response: *It is not possible to verify NTCAA's contention with available data.*

Paragraph 22: NTCAA contends that Z Global was hired by Liberty Utilities in 2011 to "validate" Sierra Pacific's full loop upgrade to 120 kV, not as an independent expert to assess applicability to existing conditions.

Response: *Comment noted.*

Paragraph 23: NTCAA contends that ZGlobal's analysis shows incremental steps can be taken to improve reliability, such as the immediate reconductoring of the 650 line to the Northstar tap; but further improvements should be tied to the demonstration of net load growth without an immediate commitment to rebuilding and operating the full loop at 120kV.

Response: *Comment noted.*

Paragraph 24: NTCAA contends that the ZGlobal analysis ran the worst single contingency scenarios, loss of the 132 line and loss of the 650 line and arrived at two scenarios. ZGlobal generated an "upgrade sequence" table for scenario 1, wherein the 625 upgrade in the Tahoe Basin was scheduled as loads reached 113 MW projected to occur in 2037 upgrade of the 625 line in 2032 or 2037.

Response: *Comment noted.*

Paragraph 25: NTCAA contends that there was no analysis of the factors reducing load growth which rendered the 1996 Capacity Plan inaccurate and outdated and no distinction between the zero load growth of the Resort-Tahoe Loop and a nearly doubling of load growth outside of the loop.

Response: *Comment noted.*

Paragraph 26: NTCAA contends that the ambient conditions (temperature and wind) associated with conductor ratings are unclear in the ZGlobal report.

Response: *ZGlobal revised the conductor ratings in response to earlier NTCAA (Besich) comments, resulting in no change in the need for the project, but affecting the timing of implementation.*

NTCAA Comments page 9

Paragraph 27: NTCAA has technical questions regarding the use of switched capacitors for voltage support, and believes that Liberty should have studies showing what levels and locations switched capacitors can be employed.

Response: *It is not possible to verify NTCAA's contention with available data.*

Paragraph 28: NTCAA contends that the ZGlobal Report proposes a partial loop at 120kV for the 650 line at the 95-110MW peak loads. Today's peak loads are about 61MW for the Resort-Tahoe loop. NTCAA contends that a partial loop sequence opens the door to specific technical thresholds prior to incurring environmental and economic costs of the full Resort-Loop at 120kV.

Response: *Comment noted.*

Paragraph 29-33, ZGlobal Time Sequence: NTCAA contends that the 625 line may not require reconstruction for two or three decades.

Response: *Comment noted.*

NTCAA Comments page 10.

NTCAA contends that the 1996 Report indicates an approach whereby Incline Substation can be backed up by additional capacity and 14.4 feeders from Brockway. NTCAA contends that the capacity to supply Incline Village is critical to any improvement to the 650 line and involves NV energy as a significant stakeholder. Furthermore, there may be the potential to transfer Brockway loads to Kings Beach.

Response: *Comment noted.*

NTCAA asks: what exactly is the agreement with NV Energy regarding the use of the Kings Beach diesel generators?

Response: *Comment noted.*

ZGlobal assumes a new load of 8MW for the approved Homewood Mountain Resort (HMR). NTCAA contends that the analysis fails to incorporate the staged construction of HMR and that loads may never reach the full 8MW. The analysis fails to assess the partial loop to Tahoe City operating at 120kV.

Response: *Comment noted.*

NTCAA Comments Page 11

NTCAA contends that depending on the “real” conductor ratings, more accurate load data, and ability to switch capacitors, the alternative staging of system upgrades could be:

- 1) Reconductor the 650 line from Truckee to Northstar. NTCAA contends that this is the only non-controversial portion of the proposed project that appears to have existing technical support for immediate installation.
- 2) Add motorized disconnects on the Truckee and Kings Beach legs;
- 3) Add switchable shunt capacitors at Tahoe City and/or Kings Beach substations;
- 4) Reconductor the Northstar to Kings Beach 650 line leg at 120kV, but continue to operate at 60kV.
- 5) Upgrade the operation between Truckee and Kings Beach to 120kV if warranted by actual load growth.
- 6) Upgrade operation of Squaw Valley to Tahoe City to 120kV.
- 7) Relocation/rebuilding of the 625 line to complete the 120kV loop.

Response: *Comment noted.*

Conclusion

NTCAA contends that what began as a project driven by the urgency to meet projected loads (1996 Capacity Plan) has evolved into one for reliability and safety during emergency conditions. However, with the significant reduction of actual loads from what was projected and with partial loop alternatives sequenced to target N-1 conditions, the urgency has lost its technical basis. NTCAA contends that the Draft EIS/EIS/EIR promotes a conceptual plan from 1996 that answers projections of net load growth that never happened. NTCAA contends that the Draft EIS/EIS/EIR is “long on fear of outage rhetoric and short on technical support to improve reliability consistent with utility engineering standards, and is therefore inadequate to technical justify the project.

Response: *Comment noted.*

North Tahoe Citizen Action Alliance

PO Box 349 Tahoe Vista, CA 96148

www.ntcaa.org

October 6, 2014

VIA EMAIL

Michael Rosauer
Project Manager, CPUC
505 Van Ness Avenue
San Francisco, CA 94102

Jack Mulligan
CEQA Counsel for the CPUC
505 Van Ness Avenue
San Francisco, CA 94102

Re: Exclusion of NTCAA's Final Comments dated February 14, 2014 from the Liberty Utilities Final EIR

Dear Mr. Rosauer:

NTCAA is informing you that our comment letter dated February 14, 2014 was excluded from the comment letters, and failed to receive any responses from the lead agencies in the Final EIR (FEIR) for the Liberty Utilities Upgrade Project. This exclusion was apparently deliberate on behalf of the lead agencies given the FEIR comments and rationale for including Tom Besich's Technical Assessment submitted April 28, 2014.

We believe this is in violation of CEQA statute § 21168.6.5 (f) (4) which states:

The lead agency need not consider written comments submitted after the close of the public comment period, unless those comments address any of the following:

(e) New information that was not reasonably known and could not have been reasonably known during the public comment period.

NTCAA submitted "Preliminary Comments" on January 7, 2014 with a detailed explanation as to why there would be Final comments submitted based on the last

minute release of key technical reports. NTCAA received an email from the CPUC on Friday January 3, 2014 with the requested technical reports attached, even though we had first requested these reports from the CPUC in January 2013. Therefore it was not the fault of NTCAA that these foundational reports were not made available for meaningful technical review prior to the close of the public comment period.

Tom Besich was extensively consulted for the technical analysis submitted by NTCAA on February 14, 2014.

In addition, Tom Besich's comments and the Paul Scheuerman Report refer directly to NTCAA's February 14th comments, yet NTCAA's comments are not in the FEIR.

NTCAA requests a detailed explanation for this omission. NTCAA further requests that this error be remedied by issuing either a supplemental FEIR or an addendum to the FEIR with point by point answers to our comments in accordance with CEQA.

You prompt response is appreciated.

Sincerely,

David McClure
President,
NTCAA

Cc: John Marshall
Bob Rodman

Technical call to discuss load measuring
From: Rosauer, Michael <michael.rosauer@cpuc.ca.gov>
Sent: Saturday, December 13, 2014 4:59 PM
To: David McClure; Jennifer Johnson; kschlichting@trisage.com
Subject: Technical call to discuss load measuring

I would like to hold the technical discussion on Tuesday at 2. Please let me know if that time does not work for anyone. This meeting is for technical staff only and no attorneys will be participating.

Thanks!

Mike

Sent from my iPhone

All,

As an outcome of the 12/17 technical call between the CPUC, NTCAA, and LU, the CPUC agreed to accept proposals from both NTCAA and LU regarding the measuring of system demand related to the proposed phased construction of the Line 625/650 project.

The proposals should include an explanation of what substation loads should be modeled in order to correctly capture the networks response to contingencies.

Also, please address the question of a large increase in load on a non-project loop substation resulting in the FEIR/FEIS/FEIS designated load trigger being met, while the actual loop load remains below the designated trigger threshold. Is it possible to set a trigger that is a subset of the full North Tahoe System Load and if so, how should that trigger point be calculated?

Finally, please discuss trigger points for project staging including how much lead time should be built in, and how it should be forecasted and what rules should be applied.

Please submit responses by January 9, 2015.

Mr. Rosauer,

January 8, 2015

As you requested at the end of our conference call on Dec 17, below are my thoughts and the NTCAA recommendation. I need to say that I appreciate your interest in resolving the technical disagreements. I was as disappointed as you no doubt were that our conference call – intended to be between you, me, and Mr. Scheuerman – was not more productive. At the end of this letter are my answers to your questions in your December 23 e-mail. I believe those answers will make sense to you after you read the following background reasons for my answers.

I. Fatal Flaws in the Analysis Relied Upon by Liberty Utilities [“LU”]:

In summary, ZGlobal and Tri Sage still have failed to provide valid engineering analysis upon which to establish a MW load “threshold” for triggering Phases 2 and 3 of the proposed project. Because only Phase 1 [reconductoring Line 650] is driven primarily by MW loads, whereas Phases 2 and 3 are caused by voltage issues [primarily VAR loads, VAR sources, and transformer modeling], there is no MW load threshold for Phases 2 and 3 that is not heavily dependent on VARs. And, the Addendum’s treatment of VARs, voltage, and voltage criteria is almost as bad as the Line 609 conductor [copper vs ACSR], winter-versus-summer ratings, and other major errors that caused the 2011 Validation report to be far less than it should have been.

As I mentioned in our conference call, I am disappointed that none of the Registered Professional Engineers [including the “electrical engineering expert” cited in the September 23, 2014 Joint Ruling] seem to see the so-obvious continuing problems that infect the 2014 Addendum, just as they failed to see the problems in the 2011 Validation study. At some point if you doubt my engineering judgment, the CPUC should seek other qualified professional help [not Mr. Scheuerman or anyone else who has been involved in this project], such as the WECC technical staff, a very experienced senior member of the IEEE Power Engineering Society, or even PGandE. I would be happy to recommend highly-experienced and qualified engineers. I remain available to explain and justify, in detail every point herein and to assist anyone you choose to give a truly independent 3rd party opinion.

II. Why the “Addendum” is Unacceptable – the “Updates”:

ZGlobal’s June 2014 Addendum lists four “updates” to the “basecase model” in the 2011 Validation study. The explanations of these “updates” are deficient, AND the Addendum includes other very significant “updates” not even mentioned that are critical to their recommendations. Among these deficiencies, the Addendum fails to properly account for existing VAR sources, AND the Addendum misstates voltage criteria and voltage results. All this is explained below, after my comments on the 4 “updates” identified in the Addendum’s “Introduction”.

The 1st “update”, regarding the Hobart Tap and Marble substation, is relatively insignificant because Hobart and Marble are well north of Truckee and the system of concern is entirely south of Truckee. It seems odd they didn’t mention their decision to separate TDPUD load from the Truckee 60kV bus and plot flows from “Summit 3”.

The 2nd “update” purports to address the issue of VAR capability of the Kings Beach diesels. However, they don’t address the issue of the reactive [MVAR] capability of the six diesel-powered electric generators when their electric power [MW] output is reduced 20%. Any experienced electrical engineer should know that a generator has greater MVAR capability when it is producing fewer MW. Those 6 diesels combined might be capable of producing 9 MVAR [or more during N-1 emergencies], not the 4 MVAR assumed in the study. LU should have the unit specification data and should share it with us. ZGlobal, Tri Sage, and Mr. Scheuerman should have recognized this and requested such specifications from LU.

The 3rd “update” concerns the very large error in impedance of a future Kings Beach 120-60kV transformer. The Addendum claims to have “corrected” this, but provides nothing explaining that correction. The power flow plot [Figure H2 on Addendum page 16 of 17] shows a 2.2% voltage drop through this lightly-loaded transformer with MWs and VARs flowing in opposite directions. The reactance/resistance ratio of such a transformer would be about 20/1. With 15 MW flowing from 60kV to 120kV and about 2.5 MVAR flowing from 120kV to 60kV, there should have been a slight [probably about 0.3%] voltage rise, not the 2.2% voltage drop. This 2.5% correction would defer Phase 3 many years. Such a transformer, if not equipped with load-tap-changing [“LTC”] -- I was surprised to hear the LU engineer say none of their transformers have LTC -- should still have a range of fixed taps [perhaps +/-10% in 2.5% steps]. Where is their assessment and recommendation regarding design and operation of this future transformer? Where is the existing 4 MVAR capacitor on the Kings Beach 60kV bus that was in the August 2011 study of the existing 2011 system? Why won’t they more accurately represent the VAR capability of the 6 diesels at Kings Beach? These corrections would eliminate the alleged voltage problems. I say “alleged” here because the proper voltage criterion is 5% drop from the starting [N-0] voltage and not their cited 5% below “nominal voltage”, and ZGlobal failed to include a basecase power flow plot showing the starting voltage [just as they failed to do so in the 2011 Validation report].

The 4th and final “update” identified in the Addendum’s “Introduction” concerns “winter line limits” – another major error in the 2011 Validation study that any experienced electrical engineer should have questioned. Here, ZGlobal’s Addendum provides a table “based on NVE provided conductor information”, “with emergency limits determined using IEEE standards.” If NVE provided this information -- specifically, the Line 609 conductor as identified by SPP in the 1996 study -- why didn’t ZGlobal and Tri Sage use it in the 2011 Validation study? Why didn’t ZGlobal and Tri Sage seek such information from NVE when their Validation study was so different from the 1996 SPP study it was supposed to “validate”? This 4th “update” cites “IEEE standards” but fails to identify which IEEE standards. Based on their failure to correctly interpret the very clear language in NERC and WECC criteria, their reference to “IEEE standards” is questionable, and needs a very explicit explanation. That table of “winter normal and

emergency” limits still shows “winter normal” as for a 77 degree F ambient temperature, which is far from “winter”, with an “emergency” increase of 25%. My prior comment was that winter normal limits for this system could easily be 25-30% higher than the 77 F values, and “emergency” situations could include another 10-20%. But, after Line 650 is reconductored, conductor thermal limits appear to only be an issue for the “no action” analysis.

III. The Unidentified and Unexplained “Updates”:

The most significant study model “update” not mentioned in the Addendum “Introduction” is the **very significant changes to loads**. Northstar’s load was increased 50% from that assumed in the Validation study’s “2011 86 MW” system, yet some of the Addendum plots are still labeled “2011 at 86 MW”. At the same time, all other North Tahoe loads are reduced 4 to 5%. Any experienced electrical engineer would know that Northstar load is very significant in a voltage study for outage of the Truckee-Northstar line section, yet this was not identified as an “update”.

Besides the MW load at Northstar, MVAR loads everywhere [including Northstar] were increased substantially, which any experienced electrical engineer would know is also very significant in a voltage-limited system. But neither of these “updates” was even mentioned with the other 4 “updates”.

The 50% load increase [4.3 MW] at Northstar appears to contradict the 5 MW increase in circuit 7203 capability included in LU’s May 15, 2014 Advice Letter filing which stated the express purpose of enabling “Liberty Utilities to support approximately five megawatts of additional load on the 7203 Distribution Line, which will help Liberty Utilities meet anticipated peak energy demand during the winter of 2014/15.” The implication was a transfer of load from Northstar to Truckee even if only for N-1s. Perhaps LU failed to inform ZGlobal and Tri Sage of this Advice Letter filing. But it remains a fact unaddressed in the Addendum AND in the FEIR [especially under the “no project” alternative, along with the other load rolling capabilities at Brockway (to Incline) and at Tahoe City (to the South Shore). This alone probably makes the FEIR deficient under CEQA and NEPA.].

Also not mentioned as an “update” [or in the analysis discussion] is the significant change in Squaw Valley 120-60kV transformer tap. In the Validation study it was plotted as 1.1; but in the Addendum it is plotted as unity [1.0]. The 1.1 tap was causing large VAR circulations between Squaw and Truckee [which the Validation study failed to plot], but there is not one word as to why they made this Addendum change – or why not something in between, such as 1.05 – other than to mention the resulting “unacceptable low voltage”. Where is the engineering analysis? Where is the engineering common sense? This has the appearance of being a fabricated voltage problem, which I want to believe was not intended.

Another very significant “update” not mentioned was the **change in voltage criterion**, from “+5%/-10% nominal voltage” in the Validation study [5.1.3 “Category B” on page 11 of 51] to “+/-5% nominal” in the Addendum [page 13 of 17]. And this change misstates the WECC/NERC

performance standard which is for percent voltage drop from the pre-contingency voltage and not from “nominal voltage” as the Addendum states.

Mr. Rosauer, to give you a feel for the impact of these unidentified, and unexplained, “updates” in the Addendum, compare plots on page 18 of 51 in the Validation report and page 5 of 17 in the Addendum: the 2011 N-1 voltage at Tahoe City which was 0.923 [7.0% lower than at the Truckee 60kV bus] in the Validation report is now 0.864 in the Addendum [13.7% lower than at the Truckee 60kV bus]. This is the direct result of the changes in what is supposed to be “2011” loads [50% increase in MW load at Northstar; all other loads reduced an average of 4-5%; plus a net 16 MVAR load increase at Northstar, Brockway, Kings Beach, and Tahoe City] and continued failure to properly model the diesels’ VAR capability.

I don’t understand why they didn’t mention these very significant “updates” in the Addendum “Introduction”, but it reminds me of the terrible Line 609 error in the Validation report.

Mr. Rosauer, let’s look at that Addendum’s analysis based on all these identified and unidentified/unexplained “updates”.

Above Figure A1 [labeled “... 2011 at 86 MW load ...”] on Addendum page 4, they wrote “voltage levels in and around Kings Beach are observed to be below 90%” – yet the Kings Beach and Brockway voltage is shown as 90.9%. 90.9 is not below 90. Note also that loading of Line 650 south of Northstar is only 91%, not greater than 100%. Yet this appears to be the only stated justification for this portion of Line 650’s reconductoring. I understand there may be some interest in relocating Line 650 away from highway 267 for aesthetic reasons even before this 100% loading limit is exceeded. I have no reason to oppose that because all my comments here relate to the accuracy of modeled electrical performance.

Underneath Figure A1 [labeled “... 2011 at 86 MW ...”] this time on Addendum page 5, note the introduction of vague language regarding that 86 MW of load: “reflective of 2011 loading”, and “reflective of 2011 conditions”. Mr. Scheuerman’s recent table of loads provided to you by Dudek’s lawyer just prior to our conference call shows this is neither 2011 nor 2012 loads. This “2011” Northstar load is apparently from 2012 [strangely up 50% versus each of the prior 4 years], yet the total of all other loads is down compared to 2011’s “86 MW” in the Validation study. Northstar’s load is up 50%, yet all other loads are down an average of 4 to 5%, with no mention nor explanation of this “update”. How can this be? And it’s labeled “2011 at 86 MW” as if it is supposed to be identical to the same plots in the Validation report.

At the bottom of Addendum page 5, under “Re-Assessment of 132 line outage”, it is implied that the only reason Line 609 no longer overloads for this outage is “applying the winter emergency ratings”. There is not one word about the significant correction in actual 609 line conductor – the issue that still begs a thorough explanation because it relates to credibility.

As noted above, at the top of Addendum page 6, their analysis of this Line 132 outage alleges “unacceptable low voltage” at Squaw Valley, but at this point, the only criterion identified was the +5/-10% nominal voltage limit in section 5.1.3 [page 11 of 51] of the Validation report. Their criterion should be a 5% drop from pre-contingency voltage, not from nominal voltage [another mistake in the Addendum]. Even with the Squaw Valley transformer tap changed to unity [instead of something closer to 1.05] the supposedly “low” voltage at Squaw Valley likely is not a drop of greater than 5%, but because they failed to provide a basecase power flow plot, we don’t know. We can estimate it from the “A1” figures as being in the 4% range, but we still need basecase plots. What would further reduce this supposed voltage violation would be a better accounting of the VAR resources at Kings Beach [the diesels and that 60kV capacitor].

The “A2” plots on pages 10 and 11 of the Addendum also allege voltage problems for loss of Line 132 even after Line 650 is reconductored, but the statement of voltages being “outside of the acceptable 5% drop” is still probably not true. As noted in the paragraph above, the operative term here is “% drop” with the percentage drop being from the basecase condition, not from “nominal” voltage. Voltages of 93-94% are less than 5% drops from the probable basecase voltages of 96-97% [as the preceding A1 plot would imply]. The Kings Beach VARs will also help.

Their analysis of the “A1” plots on pages 12 and 13 states that at “89 MW” N-1 “voltage violations begin to occur”. But the 95% voltage at Tahoe City is a drop of maybe 2-3% from its probable basecase voltage of at most 97-98% voltage. And this does not include the application of a small switchable capacitor which would be a great benefit and may already have been installed in 2014 [to accommodate load rolling from NVE’s Incline Village substation?].

At the bottom of Addendum page 13 they wrote: “Recall, that reliability standards require system voltages to be within +5/-5% of nominal voltage”, with a foot note referencing a WECC/NERC standard, and “see Table W-1, page XI-16”. “Recall”? Their only prior statement of N-1 voltage criteria was “+5%/-10% nominal voltage” on page 11 of 51 in the 2011 Validation report [section 5.1.3]. This WECC/NERC criterion is percentage voltage drop from starting voltage, not from nominal voltage. What’s more, this WECC/NERC standard is for voltage drops imposed by one utility’s outages on other utility systems [“allowable effects on others”].

Mr. Rosauer, keep in mind that these so-called voltage drops are being used, in combination with the very significant and unexplained load changes [among other unmentioned changes] in the Addendum, to advance the alleged need for Phases 2 and 3 which otherwise might not be justified for many years, perhaps decades. These subjects are not “in the weeds” as someone mentioned; they are the essence of electric power system analysis. If LU’s load changes, VAR errors, transformer errors, and voltage results are as wrong as they appear, then the justification for Phases 2 and 3 of the proposed project lacks even minimal technical support –

with what appear to be serious environmental and economic consequences for LU's ratepayers. It would be a shame for LU to follow the inappropriate recommendations in these deficient studies, and as a result have the capital costs disallowed in a rate-making prudency review.

What is most disturbing about the Addendum is not just that these major changes in power flow load assumptions are not even mentioned among the Addendum Introduction "updates" [along with other unmentioned very significant "updates"], and the power flow plots appear to misrepresent the model [eg: "2011 at 86 MW load"], but that there are what appear to be incorrect statements about voltage conditions and criteria that drive the phase 2 and 3 recommendations.

IV. NTCAA's Recommendation:

Mr. Rosauer, NTCAA and I believe the "measurement" you are seeking is not some MW figure but should be percent voltage drop at any of the 4 LU load substations [Brockway, Tahoe City, Northstar, and Squaw Valley] that cannot be corrected by voltage regulators, transformer fixed taps or load-tap-changers, switching on capacitors, or rolling load to another substation such as from Northstar to Truckee on circuit 7203 or Brockway to NVE's Incline Village substation [in the same manner NVE rolls load to Brockway for NVE's critical N-1], or from Tahoe City to the South Shore.

Furthermore, we believe the WECC/NERC voltage criterion, cited by ZGlobal, is 5% drop for N-1 from the base case [N-0] voltage. This is not what's assumed in the Addendum [5% drop from "nominal" voltage] mistakenly cited to support everything beyond reconductoring Line 650 north of Northstar.

V. What Should Be Required From LU and Its Contractors:

We found interesting the statement by Tri Sage in our conference call that the reports had been "stamped and signed" by California Registered Professional Engineers ["PE"s]. Because the 2011 Validation and 2014 Addendum reports don't identify which PEs "stamped and signed" these documents, we request that they be identified. And because the September 23, 2014 Joint Ruling appears to rely on review of "the engineering support offered by Liberty Utilities" provided by "environmental consultants retained to prepare a joint environmental document", we request confirmation that this is Mr. Scheuerman [and/or someone else from Dudek?] AND confirmation that he also "stamped and signed" the 2011 Validation and 2014 Addendum reports -- and if not, why not.

It appears to us that ZGlobal, Tri Sage, LU, and by association Mr. Scheuerman, have lost credibility because of the numerous and on-going "mistakes" in the Validation and Addendum reports. Because it appears Mr. Scheuerman did not prepared, nor manage the preparation of,

these studies and reports [the 2011 Validation and 2014 Addendum] as ZGlobal and Tri Sage did, and because Mr. Scheuerman said in the conference call that he did not see the 1996 SPP report, Mr. Scheuerman should be given the opportunity to withdraw from this whole process including rescinding his "expert" review cited in the September 23, 2014 Joint Ruling.

So far, the alleged voltage "problems" are at Northstar for loss of the Truckee-Northstar line section [N-1], at Tahoe City for loss of the 60kV line from Squaw Valley [N-1], and at Squaw Valley for loss of the 120kV line from North Truckee [N-1]. Because the Addendum [and the Validation study before it] failed to provide any base case power flow plots -- and for the reasons listed below -- they have not proven these are legitimated voltage drop "problems".

Because of this lost credibility, NTCOA requests that the CPUC direct them to provide hardcopy proof regarding:

- 1) The Addendum's unexplained 50% load increase at Northstar when all other loads combined decreased 4-5% [was this really the December 30, 2012 peak?] -- which should include hourly load data for the several days around that peak;
- 2) The Addendum's unexplained inclusion of 15 MVAR of new load at Northstar [4], Brockway [5], Tahoe City [3], and Squaw Valley [3], plus about another 10 MVAR at all other substations, when the 2011 Validation study had unity power factor [zero VAR loads] and that Validation study report was approved [apparently even "stamped and signed"] by ZGlobal, Tri Sage, LU, and perhaps Mr. Scheuerman;
- 3) The Addendum's unexplained removal of the existing 4 MVAR capacitor on the Kings Beach 60kV bus that had been included in the 2011 Validation study report which was approved by ZGlobal, Tri Sage, LU, and perhaps Mr. Scheuerman;
- 4) The Addendum's continuing failure to recognize the increased VAR capability of the six [6] diesels at Kings Beach, which could easily be over twice the 4 MVAR modeled [this would include manufacturer's specifications for the generators];
- 5) The actual installed substation capacitors, including at Tahoe City [that was/is being installed to accommodate load rolling from NVE's Incline Village?];
- 6) Substation data for all transformers and voltage regulators identifying their voltage ranges and for transformers their fixed and variable taps, their winter settings, and their impedances [percent X and R];

and

7) Which 5 MW of additional load circuit 7203 is supposed to carry as a result of the reconstruction work described in the May 15, 2014 Advice Letter [associated with this proposed 625/650 Upgrade project] and recently completed.

Such proof should include hourly load charts for each substation that will determine whether the peak loads were coincident or non-coincident. If non-coincident, remember that skiers can't be on the slopes [daytime peak] and in town [night time peak] at the same time.

We would expect such proof to be provided consistent with CPUC regulations and Title 16 Section 475 (c) (11), and (e) (1) and (2).

All "corrections" to the power flow cases in the Addendum should be incorporated in a revised study that identifies specific loads and the forecasted years they are expected. As you may recall, the September 2011 Tri Sage "scoping document" [middle of page 5] made reference to "forecast studies based on normal weather, extreme cold, and extreme warm weather scenarios" completed by LU. Why has LU, or Tri Sage, not shared those "forecast studies" with us? As you also may recall, in the conference call Mr. Scheuerman [an expert on load forecasting?] seemed surprised that I would question the weather conditions associated with each of the annual peaks since 2005 in his table. If the December 30, 2012 peak was associated with "extreme" weather and tourism conditions [as I think LU has said, and as is written near the top of page 3-11 of the FEIR: "extremely heavy tourism and ski resort activity" resulting in "an extremely large electric demand peak"], a natural question would be how does that compared to the prior dozen or so peaks? And, is "extreme" the appropriate design standard?

If LU and/or its contractors are unwilling to complete these revised studies, they should provide the power flow data to NTCAA and give NTCAA permission to hire a competent electrical engineer to conduct such studies. Regardless, LU and/or its contractors should be required to provide NTCAA a complete set of power flow printouts [not just plots] for the North Tahoe system, including all input data. As NTCAA and I have stated before, we are willing to sign non-disclosure agreements to keep any confidential data secure.

VI. NTCAA's Proposal Re-phasing This Project:

NTCAA's proposal is simple and logical:

- 1) Reconductor and rebuild Line 650 north of Northstar ASAP [I still would like to know why this part wasn't accomplished years ago, separately from all other elements of the proposed project, rather than being delayed so long];
- 2) Reconductor and rebuild Line 650 south of Northstar if and when accurate power flow studies demonstrate the conductor would overload for N-1s – the Addendum shows only 91% [of what may be a non-emergency winter rating] loading for N-1, which may

be many years from exceeding 100% [this, of course, is independent of any relocation decisions associated with aesthetics or the environment];

- 3) If outage history at Northstar demonstrates unreliability that justifies 2-line service [the “fold”], then do it, but remember that the May 15, 2014 Advice Letter filing to upgrade circuit 7203 stated that this upgrade was intended to carry an additional 5 MW of Northstar load from Truckee [it’s a shame the evaluated alternatives did not include a new line from Truckee to Northstar] – I think the CAISO standard for requiring 2-line service may be as high as 100 MW [but I wouldn’t recommend that here];
- 4) If future load growth is in the Northstar area, properly evaluate building a new line from Truckee to Northstar;
- 5) Upgrade Line 650 to 120kV operation if and when accurate power flow studies prove that N-1 conditions [voltage “problems”] cannot be corrected by existing VAR sources [including the diesels] or less expensively by adding a reasonable amount of capacitors;
- 6) Only rebuild/relocate Line 625 if and when accurate power flow studies demonstrate line-loading or voltage problems that are more cost-effectively corrected by this “phase 3” of the proposal.

The December 23 E-mail Questions:

Mr. Rosauer, you asked for “an explanation of what substation loads should be modeled in order to correctly capture the networks response to contingencies”. Above was an explanation of why phases 2 and 3 [partial 120kV loop and full 120kV loop] are more dependent on MVAR assumptions [load power factors, capacitors, and the diesels] plus transformer characteristics, than on MW growth assumptions. I would expect an experienced engineer to look at the geographic map and the system single-line diagram and easily conclude that the only loads that really affect the transmission loop from Truckee through Northstar, Kings Beach, Tahoe City, and Squaw Valley are the loads at Northstar, Kings Beach/Brockway, Tahoe City, and Squaw Valley. I also would interpret “what substation loads?” to include the issue of coincident versus non-coincident peaks. The FEIR lists peak loads as “coincident” [see 3.2.4 on page 3-10 of the FEIR]. But the 50% increase at Northstar coupled with an average 4-5% decrease everywhere else implies that some loads or years may be non-coincident. This is why we all would benefit from seeing the individual substation hourly load charts for the peak days of recent years.

As NTCAA’s February 14, 2014 comments noted, the loads in the 1996 SPP and 2011 Validation studies show close to zero net load growth for Squaw Valley, Tahoe City, Brockway, plus Northstar [what NTCAA called the Tahoe Resort Loop] and substantial [about 67%] load growth outside those 4 substations at Truckee, Glenshire, and the TDPUD substations [Martis and Truckee]. All of the non-Tahoe Resort Loop substations ~~are~~ either are located at Truckee, are radial from Truckee [Glenshire], or are a very short distance from Truckee [TDPUD’s Martis

sub]. Electrically, these are essentially the same place. None of these loads close to Truckee contribute to flows on lines 650, 625, 629, 609, nor LU's section of 132 during outages. In none of the power flow studies – SPP's 1996 Capacity Plan, ZGlobal's August 2011 Validation study, or ZGlobal's June 2014 "Addendum" – is TDPUD's Martis load shown to remain on the system for outage of the 132 line. The apparent assumption has always been it would be dropped if the outage is between North Truckee and Martis. In the conference call, I think it was the ZGlobal people who may have implied that this TDPUD Martis load should now somehow be treated as served radially from Squaw Valley for outage of NVE's section of the 132 line. If NVE and TDPUD wish continued service for Martis when 132 is out, they may wish to negotiate with LU a tap of LU's 650 line, with any associated upgrades to be paid for by TDPUD.

Look at the geographical map of the project area showing Truckee [the source] with Martis very close by, and then the lines through the 4 distant substations [Northstar, Brockway/Kings Beach, Tahoe City, and Squaw Valley]. It should be obvious that the loads that affect flows on those lines are those 4 substations, and NOT the clustered loads at or near Truckee.

The 50% load increase at Northstar in the Addendum – which was labeled as being 2011, when it apparently is supposed to be a 2012 measure – is unexplained and highly suspect [especially considering the recent Advice Letter for circuit 7203 that appeared to be for moving 5 MW from Northstar to Truckee, if only during N-1s]. No one on the conference call seemed able to explain the 50% increase, nor did they appear curious about it. But even with that large jump at Northstar, the 2012 total for those 4 substations [62.8] was only 1.4 [2.3%] higher than SPP's 1996 figure [61.4]. That's 2.3% in 16 years. At the same time, the total loads outside these 4 substations grew from SPP's 1996 total of 14.8 to the Addendum's 2012 total of 24.7, an increase of 9.9 MW [67%]. 67% versus 2.3%! But LU would have 70% of all future load growth arbitrarily assigned to the 4 substations that experienced 2.3% growth in 16 years. **If the next 11 MW of system growth happens as the last 10 MW did, there will be no significant increase in line loadings to the 4 substations, nor any voltage problems. Yet, counting all loads could wrongly trigger Phases 2 and 3 of the proposal. This doesn't make sense.**

Mr. Rosauer, you also asked [regarding "the question of a large increase in load on a non-project loop substation"] if it is "possible to set a trigger that is a subset of the full North Tahoe System Load and if so, how should that trigger point be calculated". The clear answer is "it all depends on how much load and where it is." New loads in the Squaw Valley and Tahoe City area would tend to flow more on the lines through Squaw Valley. If "phase 1" has been completed [reconducting Line 650 all the way to Kings Beach], the N-1 issues likely would be voltage drop, which could be solved with capacitors [power factor correcting, and switchable] after an accurate representation of the diesel's VAR capability. If "phase 1" Line 650 reconducting south of Northstar has NOT been completed, this likely could require that

reconductoring plus the voltage corrections mentioned in the prior sentence. If general load growth has already triggered “phase 2” [after all other voltage correcting actions have been completed], and this new large load is causing voltage problems, adjusting the fixed tap on the Kings Beach 120-60kV transformer should be evaluated [it would be a shame to buy these transformers without such a thorough evaluation of this need]. If the new large load is at Squaw Valley, and it is sufficient to cause N-1 thermal problems [on Line 609], it may be beneficial to implement a remedial action scheme that splits the Squaw Valley load between Line 609 and Line 629 with separation at Squaw Valley.

If the new large load is at Northstar, the recently reinforced 7203 circuit apparently can carry 5 MW of Northstar load for N-1s, but if the remaining load still is causing a voltage drop problem at Northstar that can’t be corrected by capacitors and VARs from the diesels, and some amount of Brockway load can’t be rolled to Incline*, the alternatives might be completing “phase 3” or building a new line from Truckee to Northstar. Such a new line from Truckee would provide a 4th line into the North Tahoe area, which for N-1s would leave 3 lines, versus the 3-line system [even after “phase 3”] which has only 2 lines after N-1. Three lines versus two lines following an N-1 – it’s obvious which system is more reliable. Building such a 4th line also would be an opportunity to separate Lines 650 and 132, which in the proposed project places both 120kV lines [after “phase 2”] not just on the same right-of-way but on the same poles for miles. This is an existing reliability risk made worse by the proposed project. From a reliability perspective, this is not good, and I have been somewhat surprised that the emphasis on “reliability” has completely ignores this risk. [*when considering load rolling between Brockway and Incline, the operative term is quid pro quo – it appears all the benefits go to NVE and none go to LU. This does not seem equitable. This includes the benefit to NVE of retiring Brockway and relocating the 14.4kV source to Kings Beach with a transformer capacity increase that does not appear necessary for Brockway load. Again, where is the quid pro quo?]

If the new large load is at Northstar, and large enough, it may be best to consider building a new line to Northstar from Truckee. The problem with “phase 3” is it doesn’t really add much to the system because Line 625 is essentially a back-up line between the west side [Squaw Valley and Tahoe City] and the east side [Northstar and Kings Beach]. Line 625 never over loads for N-1s because it already has the largest conductor [397.5 AA]. If Line 625 is indeed some kind of reliability risk, why hasn’t LU presented specific outage data proving it?

Mr. Rosauer, your last question regards “trigger points for project staging including how much lead time should be built in, and how it should be forecasted and what rules should be applied.” Lead time requirements depend upon how long it would take to complete construction, as well as how competent the planners and builder are. The only available information on this was

provided by Tri Sage in the Scoping Document and then in the FEIR. I have no expertise in this area, but I would offer the following:

First, what I do have expertise in is power system analysis. The power flow studies [2011 Validation and 2014 Addendum] are so full of mistakes, or worse, that they have very limited value. Tri Sage's September 2011 "Scoping Document" says "CalPeco retained ZGlobal ... to perform this analysis. Tri Sage worked directly with ZGlobal to manage and support this process." Here, "this analysis" and "this process" appear to mean the 2011 Validation study. I don't know if this involvement in the "analysis" and the "process" reflects in any way on Tri Sage's judgment in this other area, which may be their real strength.

In Tri Sage's 2011 "Scoping Document" they recommended completing the Line 625 work several years early -- admitting to 2 years [strangely characterized as "slightly before" at the middle of page 10] and adding another year or two with inaccurate math in the load projections. [By the way, please don't interpret my silence on other language in that scoping document, or in the Validation or Addendum reports, as any kind of agreement regarding power system performance.]

There may have been some foot-dragging regarding reconductoring Line 650 north of Northstar over the last 10-15 years. The 1996 SPP Plan gave Line 650 priority over Line 629, but SPP completed Line 629 first in 2008. It is my understanding that during that period some work [undergrounding?] on the Truckee leg of Line 650 was completed, and that reconductoring and reinsulating a portion of Line 650 closest to Truckee also may have been done, but on wood poles -- I think this section was recently replaced with steel poles as part of that May 15, 2014 Advice Letter involving circuit 7203. I find it difficult to believe that rebuilding/reconductoring the rest of the Truckee leg of Line 650 would have significant environmental impacts sufficient to require a full-blown EIR -- and certainly nothing like south of Northstar into Kings Beach and relocation of Line 625. It is my understanding that among other things, the Truckee leg would not involve TRPA. This is my common sense perspective [engineer's disease] -- I could be completely wrong. Perhaps they can explain why.

As for "rules", I would think the 1st rule would be to first accurately assess system performance to determine in-service dates. Right now all we know is Line 650 north of Northstar needs reconductoring, and should have been done many years ago. Depending on load growth, load rolling, and many other factors affecting voltages, the "need" for "phase 2" could be many years or decades into the future. I would be concerned that "rules" would be abused just as the assumptions and technical analysis in the Validation study and in the Addendum have been problems.

Tom Besich



January 9, 2015

Answer of Liberty Utilities Regarding System Demand Trigger Points

Liberty Utilities offers the following information as follow-up to a conference call held on December 17, 2014 among representatives of the CPUC, NTCAA, and Liberty Utilities relating to the measuring of system demand with respect to the “triggering points” to commence construction of Phases 2 and 3 of the 625/650 Project. In a December 23 email, the Environmental Section of the Energy Division requested that NTCAA and Liberty Utilities present supporting details of the key discussion points addressed on the December 17 conference call.

Accordingly, Liberty Utilities presents the following responses to the questions set forth in the December 23 email.

1. The Substation Loads to be Included in Assessment of the Triggering Points for Phases 2 and 3 of the Project

The FEIR adopts “system demand” triggering points by which Liberty Utilities should complete construction of Phase 2 (approaching 89 MW) and Phase 3 (approaching 100 MW).¹ These “system demand” triggering points were derived from the power flowing through Liberty Utilities’ Brockway/Kings Beach, Tahoe City, Squaw Valley, Northstar and Glenshire substations, as well as TDPUD’s Martis Valley and Truckee substations and NV Energy’s Truckee substation.

The term “system demand” as used by the FEIR for purposes of projecting the triggering points represents the total load connected to the North Lake Tahoe (NLT) subtransmission system,² even if such power is consumed by electric customers located outside of Liberty Utilities’ service territory. Thus as set forth in its Opening and Reply Briefs, Liberty Utilities intends to project its future system demand for purposes of determining the triggering points for Phase 2 and Phase 3 based on the measurements from and projections of the combined peak load of the following eight substations: Brockway/Kings Beach, Tahoe City, Squaw Valley,

¹ FEIR at 3-68.

² The “NLT system” is comprised of Liberty Utilities’ Brockway/Kings Beach, Tahoe City, Squaw Valley, Northstar and Glenshire substations plus non-Liberty Utilities loads at the TDPUD and NV Energy Truckee and Martis Valley substations.

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Northstar, Glenshire, TDPUD's Martis Valley and Truckee substations, and NV Energy's Truckee substation.³

It appears that NTCAA does not oppose the 89 MW and 100 MW triggering points the FEIR adopts, but is asserting that load from the TDPUD and NV Energy substations should not be included in the calculation. NTCAA's argument is flawed because the FEIR derived the 89 MW and 100 MW triggering points based on system load characteristics that included the loads from the TDPUD and NV Energy substations. As the 89 MW and 100 MW triggering levels were derived from a "base case" which included the power flow and voltage effects of the throughput at the TDPUD and NV Energy substations, if the MW triggering points for Phase 2 and Phase 3 were to be measured based strictly on the load at the Liberty Utilities' substations, the Phase 2 and Phase 3 MW triggering points would have to be adjusted downward to properly account for the removal of the TDPUD and NV Energy substation load.

Liberty Utilities strongly recommends that the Commission adopt the FEIR's analysis and include the loads from the TDPUD and NV Energy substations for purposes of determining the Phase 2 and 3 triggering points. Inclusion of the TDPUD and NV Energy substation loads provides a more accurate picture of the actual operations of the NLT system. The existing NLT system is a looped system configured to provide high levels of reliability given the location and seasonal outage potential. The NLT system is also electrically connected to the TDPUD and NV Energy substations, and NV Energy delivers the power that Liberty Utilities then distributes to its customers through the NV Energy Truckee substation. This physically interconnected system operates under physical constraints that are irrespective of substation ownership.

The triggers and associated methodology for assessing the reliability of the NLT system were based on prudent utility practice that considers the operating performance of the entire NLT system and the interrelationships between and among all of the various system elements within that system. The TDPUD, NV Energy, and Liberty Utilities facilities are interconnected; accordingly, each respective system affects the others in ways that necessitate a broader and regional approach to planning and operations. Loads in one part of the interconnected system affect the power flow distribution throughout the entire NLT system. Thus, the FEIR's assessment of the triggering points based on the aggregate system loads provides a better analytical framework than restricting the assessment to simply the subset of loads physically located in the Liberty Utilities area.

³ Opening Brief at 10.

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There are numerous engineering principles that support the FEIR and Liberty Utilities' use of all eight substations in the analysis of the triggering points. For example:

- Should the NLT system experience an outage resulting in load being served by two radial feeds from Truckee (e.g., an outage of the Squaw Valley-Tahoe City #629 line), then the remaining operating facilities within the system, including the interconnecting TDPUD and the NV Energy facilities, must be capable of supporting all connected load without (a) loading these remaining facilities in excess of emergency limits; or (b) needing to drop customer load.
- The operational characteristics of all eight substations play a role in the voltage performance of the NLT system, which is a critical element of system reliability. Sensitive equipment, such as Liberty Utilities' distribution transformers and distribution lines, could be harmed if the NLT system is unable to maintain voltage performance.

2. Implications of Increases to Third Party Load Served from the NLT System

NTCAA asserts that loads outside of the "Resort Loop" (i.e., the loads from the TDPUD and NV Energy substations) are not material to assessing projections of when the 89 MW and 100 MW triggering points for Phases 2 and 3 will be realized.

The "Resort Loop" is a term NTCAA created in an attempt to color its arguments. The eight substations identified above (which include the TDPUD and NV Energy substations) were all included in the Project study and represented the "base case" from which the FEIR derived the 89 MW and 100 MW triggering points.⁴ The TDPUD and NV Energy substations and their associated loads are part of the integrated electric system in the North Lake Tahoe region and good utility planning warrants that the entirety of the interconnected system be evaluated for impacts and mutual effects.

NTCAA also has no basis for its argument that Liberty Utilities intends to justify the construction of Phases 2 and 3 based on load growth by TDPUD and NV Energy's customers (but impose Project costs on its own customers). Liberty Utilities does not anticipate that the TDPUD or NV Energy loads will be the driving factor for implementation of Phase 2 or 3. As Liberty Utilities has already represented to the Commission:

⁴ See e.g., FEIR at Comment 57-8.

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Answer of Liberty Utilities Regarding System Demand Trigger Points

Liberty Utilities will proceed with Phase 2 and Phase 3 only if load growth and other conditions relating to best ensuring reliability and safety on the Liberty Utilities system warrant the need (i.e., if the load at the five Liberty Utilities substations does not increase, as NTCAA projects, but the TDPUD/NV Energy substation load increases by 10 MW, and assuming no other considerations, Liberty Utilities will continue to defer Phase 2 and Phase 3 even if the respective 89 MW and 100 MW system loads the FEIR designates as triggering points are projected).⁵

3. Implementation Plan for Phases 1, 2, and 3

Liberty Utilities offers the following clarifications with respect to its implementation of each Phase of the Project:

Phase 1 (86 MW Trigger): Liberty Utilities will initiate Phase 1 immediately upon obtaining approval from each MOU participating agency and all necessary permits and authorizations. It should be noted that NTCAA fully supports the immediate construction of Phase 1.⁶ CPUC approval should be obtained in February 2015 to enable construction to begin by June 2015 and Phase 1 to be operational for the 2015-2016 winter period.

Phase 2 (89 MW Trigger): Phase 2 is limited to work within Liberty Utilities' substations intended to enable partial 120 kV loop operation. To determine when to implement Phase 2, Liberty Utilities will monitor the actual loads at the eight substations identified above and also forecast future load growth. Depending on the circumstances, Liberty Utilities may need up to 18 months from the time it determines that the system load will reach the 89 MW triggering point to provide the requisite notices, obtain any additional building permits, and procure the necessary equipment. It will then require approximately 6 months to complete construction.

⁵ See Liberty Utilities Reply Brief, filed November 12, 2014, at 4-5.

⁶ See NTCAA Opening Brief at 10.

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Depending on the circumstances, Liberty Utilities will submit a Tier 1 advice letter to the Commission by up to 6 months before the date it projects it will need to commence construction of Phase 2.⁷

Phase 3 (100 MW Trigger): To determine when to implement Phase 3, Liberty Utilities will once again monitor the actual loads and forecast future load growth as described for Phase 2 above. Given the extent of construction associated with Phase 3, Liberty Utilities will require approximately 2 years before the date it determines that load will reach the 100 MW triggering point to initiate final design, refresh resource field surveys, obtain any additional permits, procure equipment and secure the necessary property rights. It will then require 2 years to complete construction (with 8 months of actual construction during that 2 year period).

Liberty Utilities will submit a Tier 1 advice letter to the Commission no later than 6 months before its projected commencement of Phase 3 construction.

⁷ The precise schedule for Liberty Utilities to submit the Tier 1 Advice Letter for Phases 2 and 3 will be subject to its need to make adjustments based on the “real time” circumstances and in recognition of the constraints on certain construction activities in the Lake Tahoe area during significant portions of the year.

1/27/2015

Memo Re:

Summary of Liberty and NTCAA replies to the CPUC's request for a "Demand Measurement Proposal", (CPUC Email dated 12/23/2014).

The NTCAA reply focuses on what is perceived as numerous errors and changes in the basic network modeling used to identify the system load levels that would trigger the need for Phase 2 and 3. NTCAA correctly notes there have been numerous changes to system parameters, many of which have not been fully documented. NTCAA requests more information and backup than what is contained in the current Z-Global reports and addendums.

The Liberty reply offers their beliefs as to how the trigger points should be determined. They reiterate what has been set in the record, a portion being based on the Z-Global network modeling results. They correctly set the system to be modeled as the full network.

Recommendations:

- Given the goal of correctly identifying the trigger points, such points must be based on system models that are accurate.
- It is not possible to correctly identify the trigger points for Phases 2&3 without the completion of a new network study.
- All data and assumptions for a new network study should be documented and justified along with results and power flow plots, with the final deliverable being trigger points for Phases 2&3.

Paul G. Scheuerman