



THE HYDRO COMPANY, INC.

DBA THE NEVADA HYDRO COMPANY, INC.

February 25, 2014

RegionalTransmission@CAISO.com
California Independent System Operator
250 Outcropping Way
Folsom, CA 95630

RE: Comments on Draft 2013–2014 Transmission Plan

Dear Sir or Madam:

The Nevada Hydro Company (“Nevada Hydro”) has reviewed the California Independent System Operator’s (“ISO”) draft 2013–2014 Transmission Plan (“Draft Plan”) as well as the presentations and discussions at the stakeholder meeting held on February 12 (“Workshop”), and has a number of comments and observations. Particularly:

- Nevada Hydro’s Talega–Escondido/Valley–Serrano 500 kV Interconnect (the “TE/VS Interconnect”), has been incorrectly categorized as a Group 2 project should be transferred into Group 1.
- Nevada Hydro’s Lake Elsinore Advanced Pumped Storage (“LEAPS”) project is a preferred resource. Its evaluation should not be delayed. It should be assessed as such in this plan to solve from within the basin, the reliability problems in Southern California.

These projects submitted to the Request Window, connect to the grid approximately 10 miles from the now shut San Onofre Nuclear Generating Station (“SONGS”) on Path 44 – South of SONGS. As the ISO is well aware, these projects have been fully described to the ISO and its staff in Nevada Hydro’s Request Window filing and in many other interactions.

Figures discussed in the text follow this letter. Nevada Hydro is also attaching two recent Whitepapers addressing the situation in Southern California.

1. Summary of Comments

While ISO recommends a number of what are called “Group I” projects to fill the reliability need in Southern California, the ISO admits that these projects are not able to bring the system into reliability compliance in the next five to seven years.¹ Nor are they particularly timely or inexpensive. Two of the

¹/ See, for example, the Draft Plan, at p. 104, “These recommendations do not address all of the requirement identified for the San Diego and LA Basin area; they result in a residual need of up to 900 MW overall for those areas, assuming conservative estimates for their overall effectiveness and based on the resource assumptions discussed earlier. The residual need leaves room in future planning and procurement cycles to take into account changes in load forecasting as well as anticipated increases in forecasts for preferred resources – energy efficiency in particular.”

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three recommendations are estimated by ISO to enter service in 2018 and the third in 2020. The ISO has estimated the total cost for these projects at between \$870 million to \$1.08 billion. Further, its proposals for the “Group II” and Group III” projects, with the exception of Nevada Hydro’s TE/VS Interconnect, are vague and couched in terms of long-term fruition. The problem is that the area needs solutions to its reliability problems now, and denials, no matter how fervent or well-articulated, is not a good engineering or good politics.

In its review of the Draft Plan, it is clear that the ISO has before it the facts as to the dire state of affairs in Southern California and particularly in San Diego. Nevada Hydro was flabbergasted at the scope of issues Appendix C identified in San Diego area. Because it is the responsibility of the ISO to address overall system reliability in Southern California, Nevada Hydro sees also that the ISO has no solution to remedy this multi-utility problem, and that it, and the area utilities, will continue to remain out of compliance with NERC and FERC mandates. Perhaps the ISO will now seriously consider Nevada Hydro’s TE/VS Interconnect as the near term solution it is.

Nevada Hydro therefore requests:

1. As described in Section 2 below, that the TE/VS Interconnect has been incorrectly categorized as a Group 2 project should be transferred into Group 1.
2. As described in Section 3 below, the Draft Plan’s failure to treat LEAPS as a preferred resource contradicts the assumptions set forth in the Draft Plan and fails to follow the milestone schedule in the project’s interconnection agreements carefully negotiated among all of the parties, including the ISO. The ISO cannot agree with this timeline through the interconnection process and then delay the project through this TPP.

Additional comments are provided in Section 4 relating to study assumptions, other issues in the Draft Plan, and to issues in the Appendices.

2. Group 1 reliability projects for Southern California are miscategorized and do not solve the near term reliability issue

Nevada Hydro has concerns about the Group 1 classification of reliability projects in Southern California. These concerns include Nevada Hydro’s belief that the projects identified are misclassified and do not solve the reliability problem facing the region. As described below, Nevada Hydro believes that the TE/VS Interconnect rightfully should be a Class 1 project and if properly designated, the Group 1 projects would then solve the regional reliability problem as soon as 2016 or 2017 (well ahead of the other proposals), while substantially reducing the overall cost per MW of the proposed Group 1 solutions.

2.1 Categories for Southern California reliability assessment and approval are artificial and not based upon relevant criteria

Nevada Hydro sympathizes with ISO staff regarding the difficulty it faced in determining how to analyze the range of proposals it received. As presented, the ISO classified these submissions as being part of one of three “Groups”, and evaluated four Group 1 projects, while 3 projects and variations were evaluated under Group 2. Further, the ISO is recommending the Group 1 projects to its Board “at this time”.

Nevada Hydro notes that the cost of each of these Group 1 projects ranges up to “\$700 million”, although the basis for and the reliability and completeness of these estimates is not at all clear. In addition, the projects are described as being “in service” between mid-2018 and December 31, 2020.

The ISO justifies its groupings of projects a number of ways:

- First, on page 102, the Draft Plan claims that these Group 1 projects somehow “optimize the use of the existing transmission lines in the San Diego and LA Basin study area.” The Draft Plan fails to provide any support for this claim, nor why such “optimization” is important, and important enough to commit perhaps \$1 billion of ratepayer funds for this “optimization”.
- The Draft Plan also notes that with regard to the Group 2 projects, that “[S]iting is expected to be challenging for all these alternatives”² and that these Group 2 projects “represent higher cost, new transmission right of way, lengthier development timelines, and higher regulatory uncertainty that [sic] the Group 1 projects.”³ Nevada Hydro addresses why these statements are incorrect when applied to the TE/VS Interconnect in Section 2.4.
- The Draft Plan notes further on page 101, that “The recommended strategy also provides the least risk of the need for delay in compliance with OTC generation requirements.” While Nevada Hydro was not aware that the ISO has such influence over the water regulator, Nevada Hydro describes in Section 2.4 why its TE/VS Interconnect can be on-line as soon as 2016 or 2017, in time to address the OTC mandate without further disruption to the reliability of the Southern California grid.
- Finally, the Draft Plan claims on page 101, that “it is not necessary or reasonable to seek approval” of LEAPS (as a “more expensive alternative”) and the TE/VS Interconnect (as a Group 2 project) apparently because Nevada Hydro has developed timelines to meet the upcoming crisis that “are extremely aggressive and potentially unlikely to be met given the need for reliability and the higher than usual degree of uncertainty with many of the inputs into this analysis.” If Nevada Hydro understands this logic, perhaps if it had not developed its aggressive timelines to meet the need it sees, then the ISO would have considered the projects now?

Nevada Hydro developed its timeline in conjunction with the ISO and the area utilities, and reduced this timelines to firm milestones in its recently signed interconnection agreements with the ISO and area utilities. The ISO cannot at the same time agree with this timeline through the interconnection process and use it as reason to delay the project in this TPP.

To Nevada Hydro, the Group 1 projects appear to be short-term solutions to a problem better solved by taking a holistic perspective to address the full scope of problems facing the region, rather than individual localized fixes. Moreover, this must be done now.

² / The quote is from page 97 of the Draft Plan.

³ / Id. at page 101.

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Given the dire state of affairs, Nevada Hydro contends that more relevant parameters for placing candidate projects into Group 1 should relate to the maturity, effectiveness and economics of the project itself. For example:

- The project's actual routing and permit status;
- The reliability of and level of detail of engineering and cost estimates;
- The work remaining to be completed before construction can actually commence;
- The range of reliability issues the project can solve; and,
- The cost of the proposal related to the level of benefits it provides.

2.2 The identified Group 1 projects do not meet the ISO's own requirements for inclusion

Whether the identified projects were included in Group 1 because they "optimized use of existing transmission lines, because of "lower cost", shorter development schedules, or less perceived risk by the ISO, the Group 1 projects seem incorrectly classified. For example:

- Flow control at the Imperial Valley substation requires "coordination with CFE", further analysis as to the type, configuration and cost of equipment and one or more competitive solicitations. While the ISO provided no indication of the status of environmental work, engineering seems far from complete and Nevada Hydro sees no evidence of any shorter or less risky development to arrive at a hoped for June 2018 in service date.
- San Luis Rey MVAR appears to be justified only "when coupled with other projects."⁴
- Nevada Hydro wonders how the roughly \$600–700 million (presumably 2014 dollars) Mesa Loop-in project meets these standards when the ISO itself believes it cannot be in service until the end of 2020, more than 6.5 years into the future.

2.3 The projects identified in Group 1, even if implemented, do not solve the reliability problem facing Southern California

As the ISO clearly states on page 104, the Group 1 projects

do not address all of the requirement identified for the San Diego and LA Basin area; they result in a residual need of up to 900 MW overall for those areas, assuming conservative estimates for their overall effectiveness and based on the resource assumptions discussed earlier.

Nevada Hydro has also concluded that with the Group 1 projects fully implemented, the Southern California reliability problem still exists. While the Mesa Loop in project contributes to solving the reliability problem in the SCE system, it fails to protect the SCE's southern flank. It and the other Group 1 projects do not address the problem south of Serrano and in San Diego, particularly in the

⁴ / See Table 2.6–5.

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event of a system collapse (either as a G–1/N–1 or N–1–1 contingency realized). While Nevada Hydro does not minimize the importance of addressing SCE’s individual reliability concerns, it is the responsibility of the ISO to address overall system reliability in Southern California, particularly when an outage in the San Diego system so clearly affects SCE.

For example, Nevada Hydro has modeled the classic N–1–1 contingency of the loss of the IV-Miguel and Sunrise lines and has found that the identified Group 1 projects do not prevent system collapse. Figure 1 – N–1–1 SONGS Areas shows that even with roughly 500 Mvars included at SONGS, the 230 kV system is only running at 130.2 kV under the N–1–1 contingency; a collapse situation. Further, under the same assumptions, Figure 2 – N–1–1 Serrano Area and Figure 3 – N–1–1 Imperial Valley Area show a system collapse south of Serrano.

2.4 The TE/VS Interconnect should properly be classified as a Group 1 project

As described above, Nevada Hydro has concluded that the projects included in Group 1 do not meet the ISO’s own criteria. Nevada Hydro therefore urges the ISO to properly consider the TE/VS Interconnect as a Group 1 project, now. Not only is it much farther advanced than all Group 1 projects in terms of routing, permitting, engineering and cost, but it will also solve the reliability problem in Southern California economically, timely and substantially reduce the overall societal cost per MW of the Group 1 projects.

2.4.1 Permitting and Approval status

As Nevada Hydro pointed out in its Request Window filing:

- The TE/VS Interconnect has routing that has been fully vetted with the US Forest Service. As you know, 30 of the approximately 32-mile length of the line traverses the Cleveland National Forest. This vetting process involved detailed evaluation of the proposed location of each of the 170 transmission towers to be located on Forest land, as well as substation and work locations within the Forest. Project and Forest staff met and discussed each proposed location to assess existing site conditions, proposed site access methods, tower erection as well as site maintenance and rehabilitation. A sample page from the completed Forest Workbook appears as Figure 4 – Sample Page from Forest Workbook.
- The TE/VS Interconnect has most of its engineering work completed. This includes the project plan, profile, and line sag assessment prepared by SAE Towers; detailed substation design and engineering prepared by Siemens AG and cost estimate prepared by Siemens AG and Barnard Construction Inc. A sample page of SAE’s analysis appears as Figure 5 – Sample Tower Analysis Page. Nevada Hydro has provided engineering drawings and its detailed cost estimate as part of its the Request Window filing.
- The TE/VS Interconnect has rate incentives granted by the FERC after Nevada Hydro demonstrated with independent evidence that the project provides benefits to ratepayers. FERC’s Order is in docket ER06–278, and was included in the Request Window filing. This Order from the FERC will allow Nevada Hydro to move rapidly from permitting to construction.

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- The TE/VS Interconnect has a final environmental impact statement (“FEIS”) that has been issued by FERC addressing both the TE/VS Interconnect and the sister LEAPS project describing the project FERC could approve and the mitigations it and the Forest Service would impose on the approved project. The FEIS is now in the process of being updated.
- The California Public Utilities Commission (“PUC”) has completed an extensive analysis of the TE/VS Interconnect under the California Environmental Quality Act (“CEQA”) in connection with its analysis of the Sunrise Powerlink project proposed by SDG&E.⁵ That analysis included a review of the TE/VS Interconnect as a CEQA alternative to Sunrise. The TE/VS Interconnect was identified as the environmentally superior transmission project in that proceeding.
- Nevada Hydro is preparing to refile its own application to the PUC for approval of the TE/VS Interconnect shortly.

With its routing vetted with the landowner, and with much of the environmental work and engineering complete, Nevada Hydro is confident that its present estimate of \$750 will not vary substantially. This cost includes all costs; including detailed interconnection upgrade costs from SCE and SDG&E, mitigation costs, and all financing costs. Nevada Hydro does not believe the other Group 1 projects have anything close to the level of detail Nevada Hydro has, most of which has been provided to ISO staff. Nevada Hydro is also confident that at this cost, the system benefits will far outweigh the project’s cost, thereby meeting the test to receive approval from the PUC.

As a result, Nevada Hydro can have the TE/VS Interconnect project operating well ahead of other proposed Group 1 projects identified in the Draft Plan. With some cooperation from permit authorities, Nevada Hydro’s real time estimate for commercial operation is late 2016 or early 2017, placing it at the leading end of the other projects identified in Group 1.

2.4.2 The TE/VS Interconnect will solve the reliability crisis in Southern California

As Nevada Hydro noted in Section 2.3, the identified Group 1 projects fail to solve the reliability issue in Southern California. However, when the TE/VS Interconnect is added to Group 1, the system becomes stable. Powerflow diagrams showing the effect of incorporating the TE/VS Interconnect into the Southern California system are provided in the following self-explanatory figures:

Figure 6 – N-1-1 with TE/VS Interconnect, SONGS Area

Figure 7 – N-1-1 with TE/VS Interconnect, IV Area

Figure 8 – N-1-1 with TE/VS Interconnect, Serrano Area

⁵ / *In the Matter of the Application of San Diego Gas & Electric Company for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project, Application 06-08-010.*

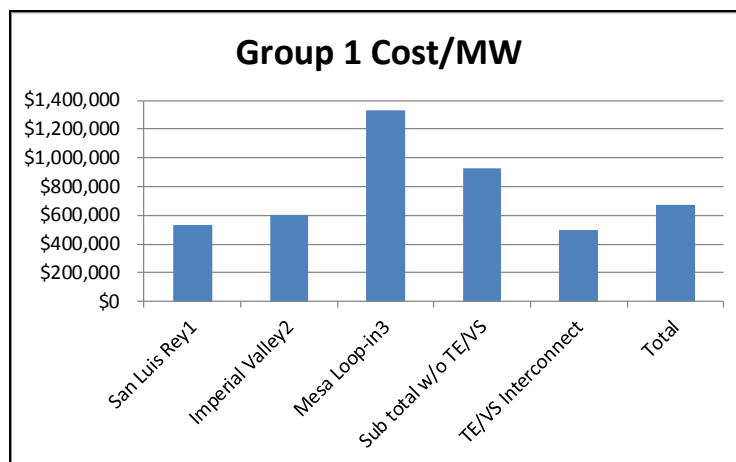
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2.4.3 The TE/VS Interconnect will reduce the cost per MW of approved Group 1 Projects

Nevada Hydro's extremely detailed cost estimate combined with the ISO's own estimate that the TE/VS Interconnect will be able to import at least 1,500 MW (Nevada Hydro believes the figure is 1,800 MW), will allow the TE/VS Interconnect to reduce the cost per MW of approved Group 1 projects from more than \$925,000 to less than \$675,000—more than a 30% reduction. These calculations are shown below. Nevada Hydro notes that of the projects presently identified in Group 1, all have a higher cost per MW than does the TE/VS Interconnect, even though the TE/VS Interconnect has a detailed, inclusive and nearly firm cost.

Group 1 Cost per MW with TE/VS Interconnect

Project	Cost (\$)	MW	Cost/MW
San Luis Rey ¹	\$80,000,000	150	\$533,333
Imperial Valley ²	\$240,000,000	400	\$600,000
Mesa Loop-in ³	\$625,000,000	470	\$1,329,787
Sub total w/o TE/VS	\$945,000,000	1,020	\$926,471
TE/VS Interconnect	\$750,000,000	1,500	\$500,000
Total	\$1,695,000,000	2,520	\$672,619
¹ / Average of range of local resource reduction benefit			
² / Phase shifter estimates used			
³ / Average of range of cost and local resource reduction benefit			



Source: The Nevada Hydro Company

3. LEAPS should have been included as a Preferred Resource in the LA Basin and was not

In Section 1.8 of the Draft Plan, the ISO discusses its analysis of how “non-conventional”, “non-transmission” or “preferred resources” “can constitute non-conventional solutions to meet local area

needs that otherwise would require new transmission or conventional generation infrastructure.” The Draft Plan notes on page 26 that

The general application for this methodology is in grid area situations where a non-conventional alternative, such as demand response or some mix of preferred resources could be selected as the preferred solution in the ISO’s transmission plan rather than the conventional transmission or generation solution. This would be possible in situations where the timeline for an identified need allows time for monitoring the development of non-conventional alternatives before a conventional solution would be required to be approved.

The Draft Plan describes, on page 8, “non-conventional resources” as including, for example demand response and storage. The Draft Plan never exactly describes what the term “non-transmission resources” means, although it is mentioned throughout the document.⁶ With regard to “preferred resources”, perhaps ISO staff is not clear on its own definition. If we heard correctly during his Workshop comments, Mr. Stark advised that Nevada Hydro’s LEAPS facility is not a “preferred resource.” Clearly, he is incorrect, as section 1.8 of the Draft Plan, describes “preferred resources” as including energy storage.”

Further, and as noted in the CPUC’s recent Track 4 Long Term Procurement Decision,

Each utility should solicit all resources as required by this decision, and may propose for approval any set of resources which can meet the LCR need in its portion of the SONGS service area consistent with the authorized resource ranges herein. Within the categories that include preferred resources, bulk energy storage and large pumped hydro facilities should not be excluded.⁷

LEAPS is clearly an “energy storage” facility located in the load pocket. Whether the ISO is considering “non-conventional”, “non-transmission” or, “preferred resources”, it should have analyzed Nevada Hydro’s LEAPS pumped storage project in this Section, and clearly, it did not. This is particularly troubling to Nevada Hydro when the ISO states on page 27 that:

The ISO applied in the current planning cycle a variation of this new approach in principle to several specific local areas in Southern California: the LA Basin and San Diego areas. Because of the magnitude of the projected reliability needs in these areas incremental transmission options were also studied to complement non-conventional alternatives (i.e., preferred resources) to reduce the need for conventional generation to fill the gap. Thus, unlike the generic application of the methodology in future transmission planning process cycles where preferred resources are considered as an alternative to transmission, the main focus of this effort with respect to the LA Basin and San Diego areas was to evaluate non-

⁶ / See for example, the discussions on pages 7, 19, 26 and 90.

⁷ / Decision Authorizing Long-Term Procurement for Local Capacity Requirements Due to Permanent Retirement of the San Onofre Nuclear Generations Stations, R12-03-014, Mailed February 11, 2014, Page 99.

conventional alternatives and identify performance attributes needed from these alternatives that could effectively address the local reliability needs in these two priority areas as part of a basket of resources.

Further errors relative to LEAPS as are found in the following assertions, from page 27:

In the course of reviewing energy storage projects — both battery and pumped hydro — proposed in this planning cycle as mitigations to reliability needs, the ISO developed a further appreciation for considerations that will need to be refined in future planning cycles. These projects were proposed as rate-based transmission assets, as opposed to market assets providing local resource capacity to utilities, and as such, are precluded from other market participation. While we could not recommend approval of these projects in this cycle for other reasons, we believe energy storage projects have significant potential for addressing renewable integration needs and plan to evaluate this potential in future cycles as well as potential barriers to achieving this potential. [Emphasis added.]

First, Nevada Hydro requests that the ISO specify what “considerations” it will need to “refine” in future planning cycles and why these considerations could not have been applied to LEAPS now. Further, Nevada Hydro did not propose that LEAPS be included in any “rate base” as claimed⁸. Third, the ISO must clearly specify the reasons why it could not “recommend approval of these projects in this cycle”.

Also on page 27, the ISO notes that:

As the ISO’s work in this area evolved in determining the necessary attributes, it received several sets of preferred resource development scenario input data from Southern California Edison for the LA Basin.

In Footnote 9, the ISO noted that, “No other stakeholders provided preferred resource scenario input data for consideration by the ISO.” Nevada Hydro was not aware that the ISO had requested such scenarios, but was aware that the ISO was to “evaluate non-conventional alternatives and identify performance attributes needed from these alternatives that could effectively address the local reliability needs in these two priority areas as part of a basket of resources”⁹. In its Request Window filing, Nevada Hydro provided detailed operational attributes of LEAPS for use by the ISO for this process. As these operating attributes of LEAPS we apparently ignored for those provided by SCE, Nevada Hydro requests that the operating scenarios for LEAPS be added to the analysis described in this section of the final report.

⁸ / Nevada Hydro acknowledges that at one point it had worked with the ISO to determine whether rate-basing LEAPS was appropriate. At the time, it was determined not to be appropriate. Nevada Hydro notes that the provisions of the Energy Policy Act of 2005 potentially allow pumped storage to be considered a transmission asset and thereby eligible for rate base consideration. Nevada Hydro therefore, reserves its rights accordingly.

⁹ / Draft Plan, page 27.

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4. Other Comments

4.1 Nevada Hydro agrees that the ISO is facing “unique challenges”

In the Forward to the Draft Plan, the ISO admits to a particularly “unique challenge” it is facing:

Transmission solutions that are pushing the boundaries of optimizing existing assets and require extensive implementation coordination with neighboring systems.

Nevada Hydro agrees wholeheartedly. It has reviewed the WECC summary of the SCE system in the 2023 heavy summer load flow case, shown in Figure 9 – WECC System Summary for SCE¹⁰. This analysis more than supports the ISO’s concern. As shown by WECC, the system load for the SCE system is modeled with a leading power factor, with 2182.1 Mvar in excess of a net balance of reactive power consumption versus reactive power provision at the load points. This is a highly unusual condition for heavy load times, and is unique in WECC for all its systems in the case. Nevada Hydro also notes the following:

- Regarding the transmission line losses and charging for 500 kV lines and 230 kV lines, the reactive power losses for the two voltages are approximately 15 times the real power losses. Nevada Hydro also notes that the line charging for the 500 kV lines versus the line losses is approximately the inverse of the situation for the 230 kV lines.
- Regarding the difference between the real power and reactive power losses and line charging for the 115 kV and 66 kV lines, with little charging to offset the reactive losses, the reactive power losses, at about 3,500 Mvar, is a significant drag on system voltage.
- The total of all line charging is approximately half of the losses, and over a third of that charging comes from the 500 kV.
- Under critical contingency situations, reactive power losses increase. This is a major problem when the loss of elements of the backbone transmission is lost and flows are increased on the 230 kV system.

This data confirms the sense reflected in the Draft Plan that the present system has been pushed to its reliability limits. It also shows that the future for transmission in Southern California will require the move to a 500 kV base more extensive than is presently in place. This is especially important as the amount of generation in the coastal regions of Southern California declines because of regulator pressures and aging, balanced by new generation sources requiring large land areas not available near the coast.

Nevada Hydro recent Whitepaper titled, “Future Transmission Needs in Southern California” is attached to provide additional reference material.

¹⁰/The values shown are from the WECC 2023 hs1 base case, and are for system normal conditions.

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4.2 Generator Interconnection and Deliverability Allocation Procedures

The Draft Plan describes the procedures it intends to use to assess interconnection and deliverability commencing on page 20. However, these procedures fail to take account the present status of the LEAPS project, specifically, its queue position, its completed interconnection agreements and the timing of milestones agreed therein and the fact that deliverability studies are long complete.

The new procedures described in Section 1.3 at page 20 introduces

a new planning objective into the transmission planning process: to provide deliverability status for new generating resources in a total amount and geographic distribution corresponding to the base case resource portfolio the ISO uses in the transmission planning process for purposes of identifying public policy-driven transmission solutions. In this way, the transmission planning process identifies any policy-driven upgrades needed to provide deliverability status to a generation portfolio that is consistent both in total volume and geographic distribution with how the state expects its LSEs to procure resources to meet their 33 percent RPS requirements.

In Nevada Hydro's view, this new procedure is fundamentally unfair to those projects, like LEAPS, that have already been through the interconnection approval process and that provide resources that will allow LSEs to meet their RPS requirements today. LEAPS, like other higher queued projects, has deliverability, is absorbing all upgrade costs and has executed interconnect agreements with definitive timetables.

4.3 Renewable Integration

On page 25–26, the ISO notes that it is now planning to address flexible resources in the 2014–2015 transmission plan where it will also look at overgeneration. While the Draft Plan notes that “[R]enewable integration operational studies have focused in particular on the need for flexible resource capabilities”, the ISO continues to largely push aside the LEAPS facility, which will be the most flexible of resources to be located in the Southern California load pocket with the ability to address the loss of SONGS, now. Because it is the responsibility of the ISO to manage the state's grid, Nevada Hydro urges the ISO to address flexible resources as a high priority item. Particularly as resources like LEAPS can serve multiple needs in the reliability impaired Southern California grid, it must be assessed holistically, including the full range of benefits advanced pumped hydro projects can contribute to grid stability and operation. Nevada Hydro would be pleased to work closely with ISO staff on this endeavor.

4.4 Study Assumptions

Nevada Hydro is concerned that some of the study assumptions do not reflect the real world limitations of the present system. An example of this missed limitation may be found in Table 2.3-5. Here, the ISO has included the ratings of WECC Paths 43 and 44 at their levels before the retirement of SONGS. While Nevada Hydro believes these limits no longer apply, this is an

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example of the complexity of planning in this area, with the prospect of missed understandings of limits, which could lead to the kind of disaster noted in the “FERC/NERC Staff Report on the September 8, 2011 Blackout”. As the ISO is well aware, the staff of these national regulatory bodies conducted an intensive review of the operating and planning practices of the responsible bodies in Southern California and WECC. The report draws parallels between the August 2003 blackout in the northeastern U.S. and this event. The report states,

“Similarly, this inquiry’s report found that several entities’ operational and long-term studies did not adequately ensure the reliable operation of their systems. Specifically, both reports described relevant planning studies that: (1) did not adequately identify and study critical external facilities; (2) did not adequately analyze potential contingency scenarios; and (3) were based on inaccurate models and invalid system operating limits (SOLs).”¹¹

4.5 Comments on Appendix A

Nevada Hydro understands that Appendix A is primarily set out to define the generation to be modeled in the various analyses to be conducted as part of the Draft Plan. While the tables for existing generation are clear, there seems to be confusion about whether the Maximum Capacity values listed are gross values (before station service use is deducted) or net values. For example, the “Maximum Capacity” listed for Alamitos is shown as 2,010 MW. This appears to be a gross generation value, since the Pmax shown in load flow cases reflects 1,950 MW for this station. On the other hand, the values shown for SDG&E stations, listed by unit rather than plant total, appear to be net values. The generation shown for Palomar and Otay Mesa are shown as a block.

In addition:

- The Ocotillo Express wind farm probably should be considered to be outside the San Diego load pocket since it is outside of the load pocket for the most critical contingency facing SDG&E. This appears to be the principle applied in not listing the generation located near Imperial Valley, and should be carried through for Ocotillo Express.
- While Breggo Solar has many projects in the San Diego load area, it is distributed generation and should be included as part of that classification, not as a central station.
- The planned new generation includes the Carlsbad Project. It is listed for service in 2016. Nevada Hydro understands that permitting and contracting for the plant is not yet final. Further, if the facility continues as a combined cycle project, construction is generally around thirty months. Unless the facility is to be built with a simpler configuration, it appears that even under the best of circumstances, Carlsbad will miss service in the 2016 summer peak period. As noted, Carlsbad does not yet have a tolling agreement in place. This has been an issue for some time, and it is overly optimistic to assume this issue away now.

¹¹ / “FERC/NERC Staff Report on the September 8, 2011 Blackout”, P. 125

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- While the Pio Pico Project may not take as long to build as Carlsbad, nevertheless it still has not cleared all pre-construction hurdles. It would be inappropriate to include the project before 2017 without special awareness that all pre-construction hurdles have been cleared.

Finally, there appears to be a category of generation missing from this appendix: The generating units that will be retired for lack of mitigation in compliance with the “Once-Through-Cooling” order. It would be appropriate to add a table showing these units, their required mitigation deadline, and if mitigation is not forthcoming, whether and how much prospective replacement generation is planned and when will it be available for service. Nevada Hydro understands that this is a particularly knotty problem, especially in such complex sites as Huntington Beach.

4.6 Comments on Appendix B

Nevada Hydro reviewed Table B3-2 and observed two optimistic and one very surprising assumption in the notes for the table. In terms of rose-colored glasses, Nevada Hydro believes that it is extremely optimistic to assume that Long Beach and the Etiwanda are not being retired. Nevada Hydro believes that it would be a better planning practice to assume that these units are to be retired. This more conservative assumption would help avoid surprising and troublesome outcomes that the ISO would face if it assumed these older and less efficient units were available but turned out to be unavailable.

Nevada Hydro was also surprised to see that the ISO is assuming that the Encina Station will meet OTC compliance by 2018. We imagine that the City of Carlsbad would be surprised as well. As the ISO provided no support for this surprising statement, it is difficult to believe, particularly as its retirement is being coordinated with development of the Carlsbad Project.

Further on Table B3-2, Nevada Hydro suggests that “Conventional Resource Need”, may need to be revised if it is deemed prudent to reconsider the status of any of the Long Beach, Etiwanda and Encina units.

Omitted from the discussion surrounding Table B3-4 is any indication of what year is being considered.

Nonetheless, Nevada Hydro can only conclude from the information presented that the system is in dire trouble for any of the combinations of equipment additions and non-conventional transmission assessments. Of the fourteen possible combinations, only five do not lead to system collapse. And of those five, there is no indication of whether there is compliance with transmission element loading limits. It is likely that if the more conservative assumption on the Long Beach, Etiwanda and Encina units were considered, that none of the options in Table B3-4 would result in anything but a system blackout under the critical contingency.

4.7 Comments on Appendix C

Nevada Hydro has reviewed Appendix C and saw that the impacts of contingencies in SCE and SDG&E systems show that the San Diego system has many and major problems. While SCE has a few thermal overload issues under Category B and a dozen under Category C, SDG&E has dozens of problems, a listing covering 40 pages. These range from some Category A to Category C,

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including the loss of the two 500 kV lines into the San Diego load area from Imperial Valley. The types of trouble include thermal overloads, voltage deviations, high or low voltage and “voltage instability” (meaning voltage collapse/blackout).

It should be obvious that SDG&E and the ISO have a considerable amount of work to bring this system into reliability compliance. Further, the Appendix acknowledges that some of the problems, which are major, cannot be corrected by the SONGS retirement mitigation strategy through the Group I projects. Without the completion of at least a portion of the Nevada Hydro’s TE/VS Interconnect, no correction of the reliability shortfall will be possible before 2020 and perhaps later still.

It is apparent to Nevada Hydro that the path set out in this Draft Plan will leave San Diego’s system integrity in jeopardy until sometime in the next decade. While we understand it may be difficult to hear, the ISO’s only choice may be to move the TE/VS Interconnect to its Group I project list and to pursue its completion with all due haste. While it would be advantageous to have both the Case Springs to Talega 500 kV path and the Case Springs to Rainbow/Escondido path in service, it is possible to gain the needed reliability improvement in a stepwise fashion. This would consist of completing the Case Springs-Rainbow/Escondido portion as soon as possible, probably 2016. Initial testing of system performance with just this leg in place for 2016 heavy summer conditions showed that a system collapse would be avoided for the two major contingencies (L-1-1 or G-1/L-1). Of course having both branches, Case Springs to Talega included, would allow the system to weather the potential contingencies handily.

Even if there is some delay (perhaps due to transformer delivery schedules) and the completion of the Talega leg were delayed until 2017, that would still provide an adequate reliability result and still ahead of the partial solutions in the present Group 1 configuration.

Nevada Hydro suggests that while the construction work to complete TE/VS in its extended form is in progress, it would be prudent to conduct the development work on the Suncrest to Escondido/Rainbow and on converting the Serrano-SONGS 230 kV line to a Serrano-Talega 500 kV line. Completion of this or a similar project would then provide the transmission capability to handle the impacts of the once-through-cooling retirements.

Nevada Hydro notes that the change in reactive power consumption when moving from a normal condition to the N-1-1 worse case situation is about 4,000 MVar. The Group I reactive supply projects are an important part of the reliability problem’s solution, but cannot achieve such a result themselves.

5. Conclusion

The ISO has all the facts it needs scattered throughout the Draft Plan. Clearly, the San Diego area particularly is in dire trouble. Clearly too, the situation needs to be address now, to avoid additional fines being levied after the next crisis occurs.

The ISO has the tools it needs to solve the problem quickly in the TE/VS Interconnect and, as described herein needs to:

February 25, 2014

- Move the TE/VS Interconnect into Group 1.
- Assess LEAPS is a preferred in basin resource in this planning cycle.

Nevada Hydro and its development team is standing by to help in any way it can to alleviate the pending crisis. We hope that the ISO will allow us to help.

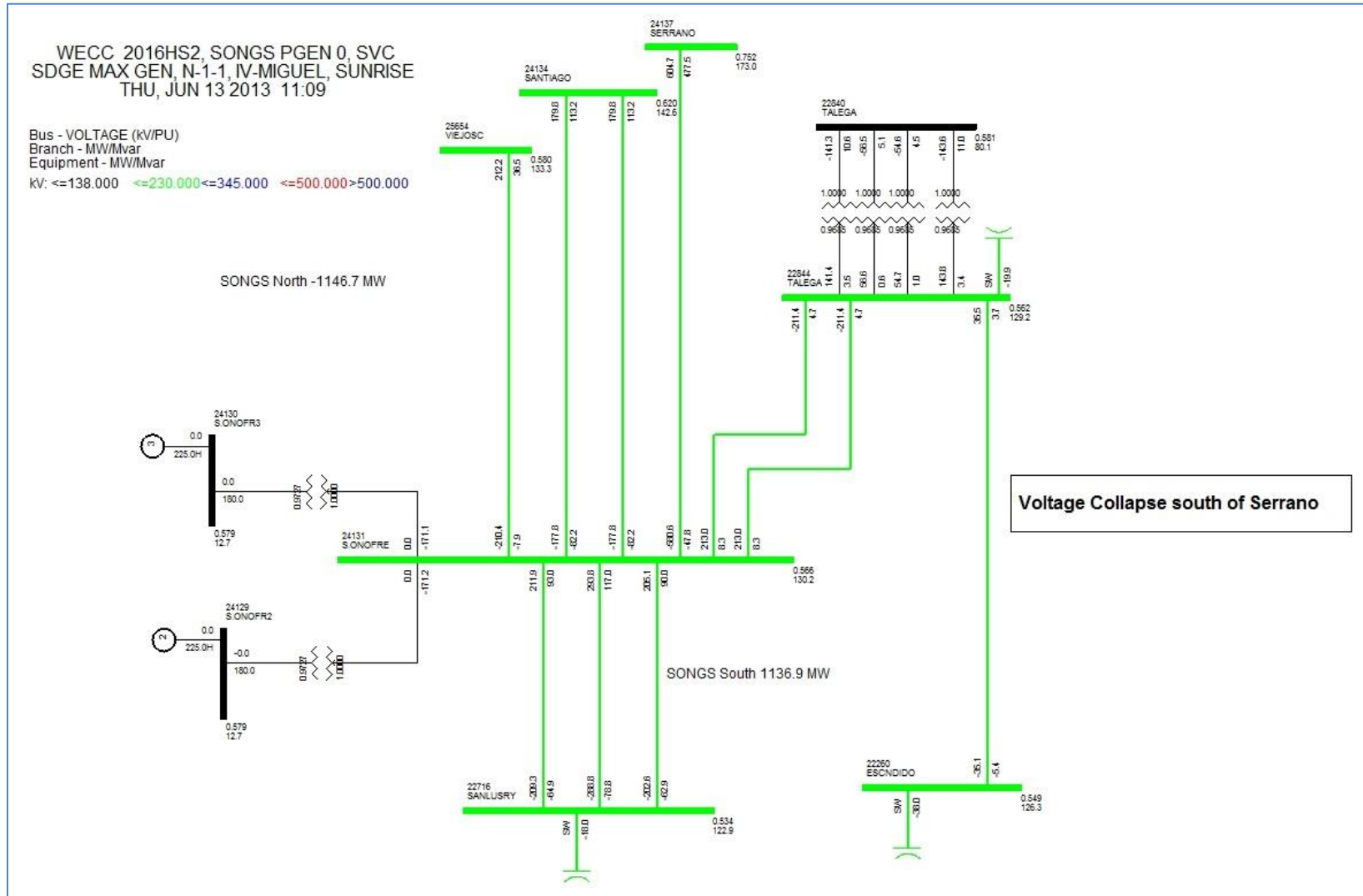
Sincerely,

David Kates

Attachments

Figures

Figure 1 – N-1-1 SONGS Area



Source: The Nevada Hydro Company

WECC 2016HS2, SONGS PGEN 0, SVC
SDGE MAX GEN, N-1-1, IV-MIGUEL, SUNRISE
THU, JUN 13 2013 11:11

Bus - VOLTAGE (kV/PU)
Branch - MW/Mvar
Equipment - MW/Mvar
kV: <=30.000 <=230.000 <=345.000 <=500.000 >500.000

24086 LUGO
1337.9
624.8
0.933
466.6
-1330.3
-506.1
24236 RANCHVST
0.888
443.8
554.4
350.0
-552.9
-357.9
-774.8
-461.2
24138 SERRANO
0.860
429.8
24845 ALBERHILL
777.9
-1045.3
-530.8
1048.0
570.8
24151 VALLEYSC
0.922
461.0
24025 CHINO
SW
-48.6
45.1
90.6
0.783
180.1
24137 SERRANO
-44.9
-92.0
-690.0
-264.7
-743.7
-263.1
-716.7
-244.2
0.752
173.0
24131 SONOFRE
-580.6
-47.8
303.8
39.3
303.8
39.3
550.8
50.0
550.8
50.0
-549.8
-32.9
-32.9
SW
0.0
24154 VILLA PK
0.749
172.2
25201 LEWIS
-303.1
-28.5
-303.1
-28.5
0.747
171.8
Voltage Collapse South of Serrano 500 kV

Source: The Nevada Hydro Company

WECC 2016HS2, SONGS PGEN 0, SVC
SDGE MAX GEN, N-1-1, IV-MIGUEL, SUNRISE
THU, JUN 13 2013 11:12

22885 CENTRALS
0.553
278.7

22468 MIGUEL
0.501
250.6

21918 DIXIE230
1.010
232.3
15.3
-7.49

21025 ELCENTRO
1.001
230.1
-154.6
-8.3

22536 N.GILA
-823.1
21.2
1.056
528.0

22360 IMPRLVLY
-179.8
14.6
-321.1
26.8
-324.2
24.8
1.054
527.2

22396 IMPRLVLY
179.9
-7.5
320.2
-13.1
324.3
-12.1
75.1
-19.6
155.5
8.6

22998 IV-NTB
1.006
231.4
3.2
-28.1
20118 ROA-230
262.3
262.3
5.1
262.3
1.011
232.5

22984 IV-GEN
1.010
232.3
265.0
-9.3
265.0
-9.3
12.8
-264.3
12.8
-264.3

1
1.009
232.0
-3.2
24.3
-261.8
-2.0
-261.8
-2.0

Voltage collapse south of Serrano 500 kV

Otay Mesa-Tijuana SPS Exercised

Imperial Valley 500 kV and Connections

Source: The Nevada Hydro Company

Figure 4 – Sample Page from Forest Workbook

Cleveland National Forest
Talega-Escondido/Valley Serrano 500 kV Interconnect
FERC P-11858-002, CPUC 07-10-005

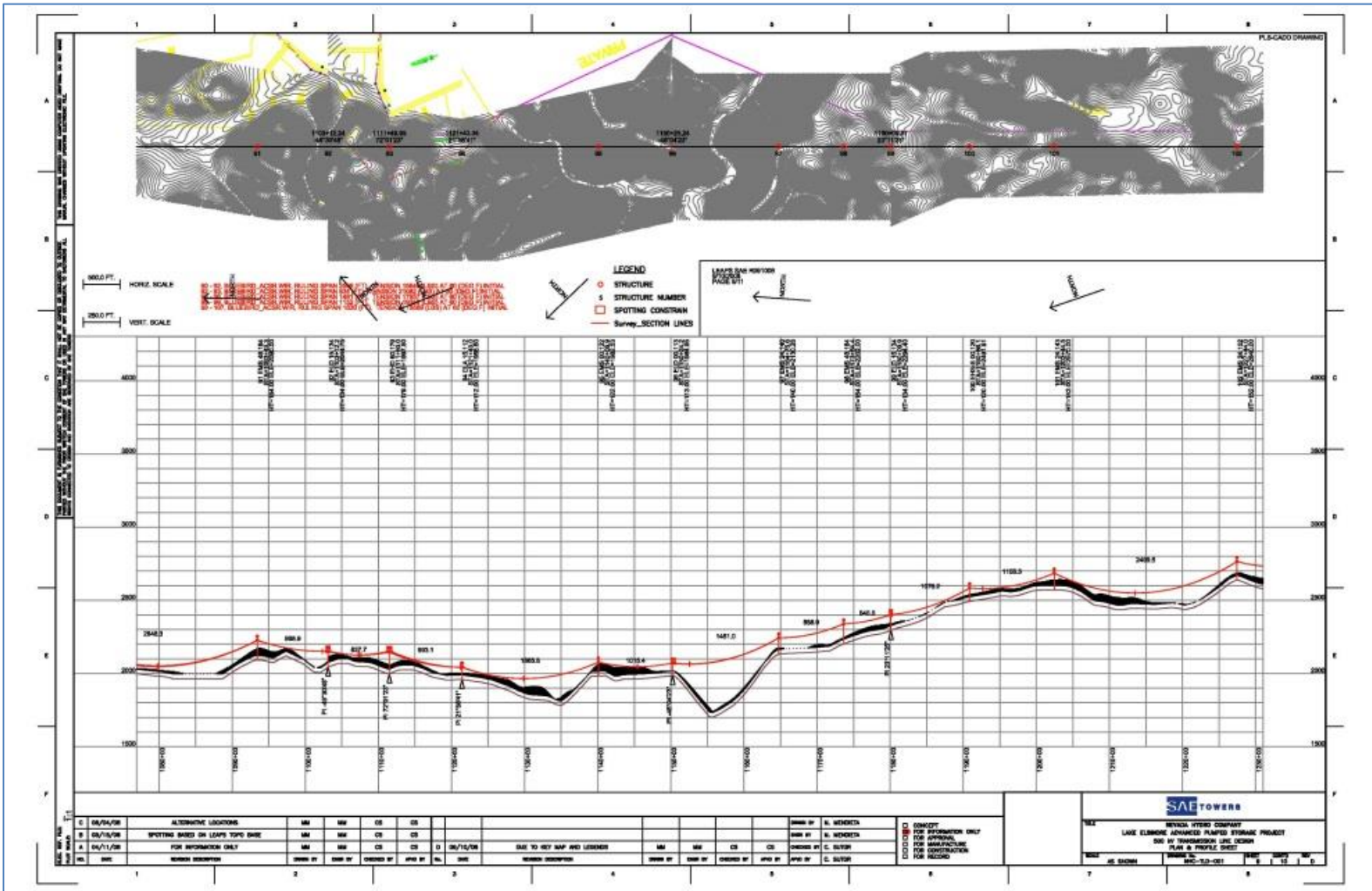
USFS Tower Worksheet

Date:	9 September 2008
Tower ID Number:	1
Milepost in Tenths of Statute Mile:	0.0
Latitude:	33° 46' 2"
Longitude:	-117° 25' 16"
Tower Elevation MSL (Ft.):	2715.000
Tower Height (Ft.):	107.0
Tower Type:	Lattice 0° - 60° - Dead End Tower
Tower Drawing Number:	eld-t
Base Square Ft:	29.632

Tower Finish:		<input checked="" type="checkbox"/> Standard Non-Specular Finish
		<input type="checkbox"/> Special Paint Color
	Specify Custom Paint Colors:	
Tower Access Road:		<input type="checkbox"/> No planned Access Road
		<input checked="" type="checkbox"/> Access Road Possible
	Proposed Length of Access Road:	75 ft.
Sensitive Biological Survey:		<input checked="" type="checkbox"/> Survey Completed
		<input type="checkbox"/> Survey Not Completed
	Date Survey Completed:	5/28/08
Trees at Tower Location:		<input checked="" type="checkbox"/> No Trees at this Location
		<input type="checkbox"/> Trees Found at this Location
	Estimated Quantity of Trees:	
Special Requirements:		<input checked="" type="checkbox"/> No Special Requirements
		<input type="checkbox"/> Site Has Special Requirements
Describe Requirements:		

Source: The Nevada Hydro Company

Figure 5 – Sample Tower Analysis Page



Source: The Nevada Hydro Company

Figure 6 – N-1-1 with TE/Vs Interconnect, SONGS Area

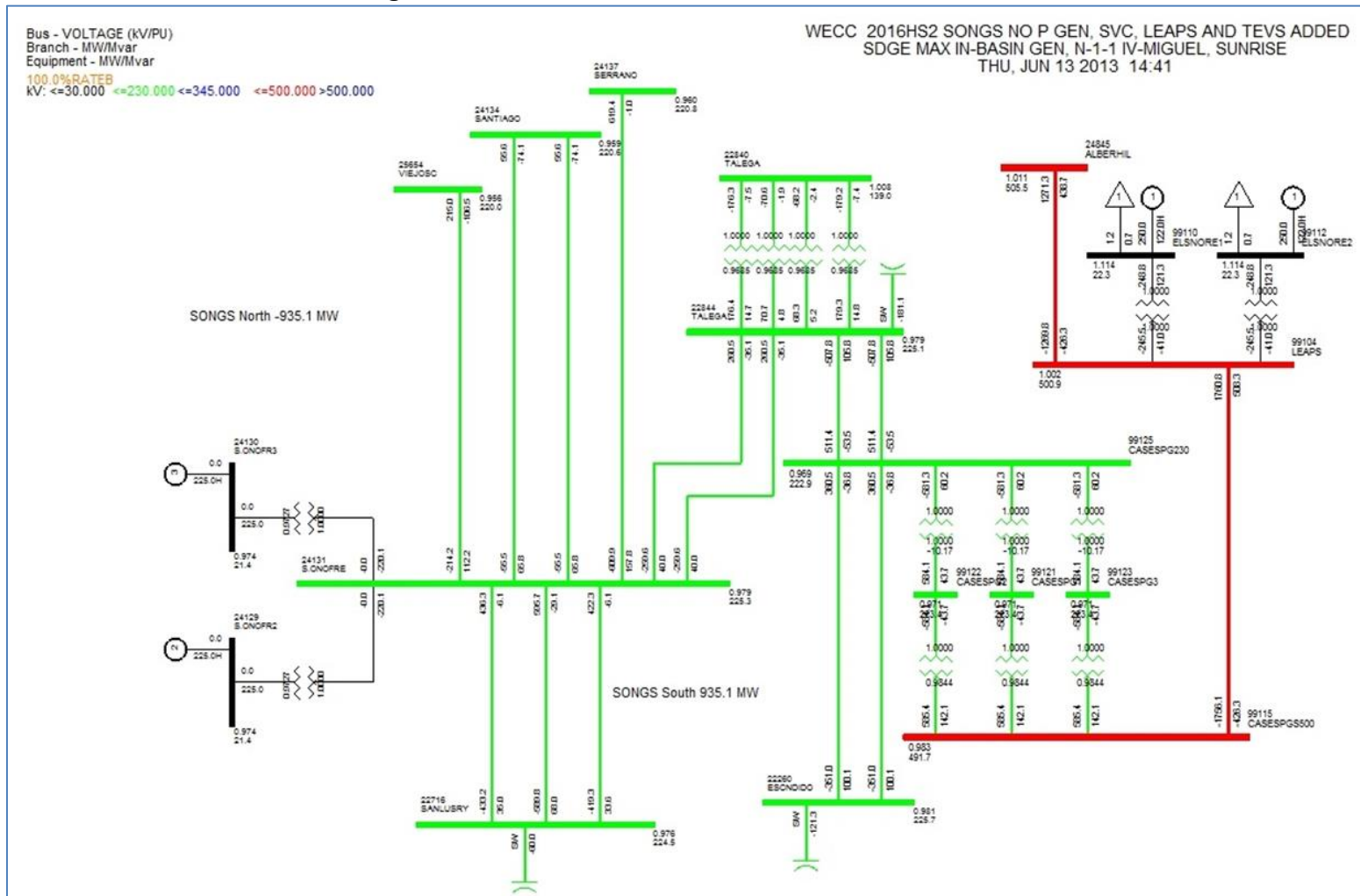
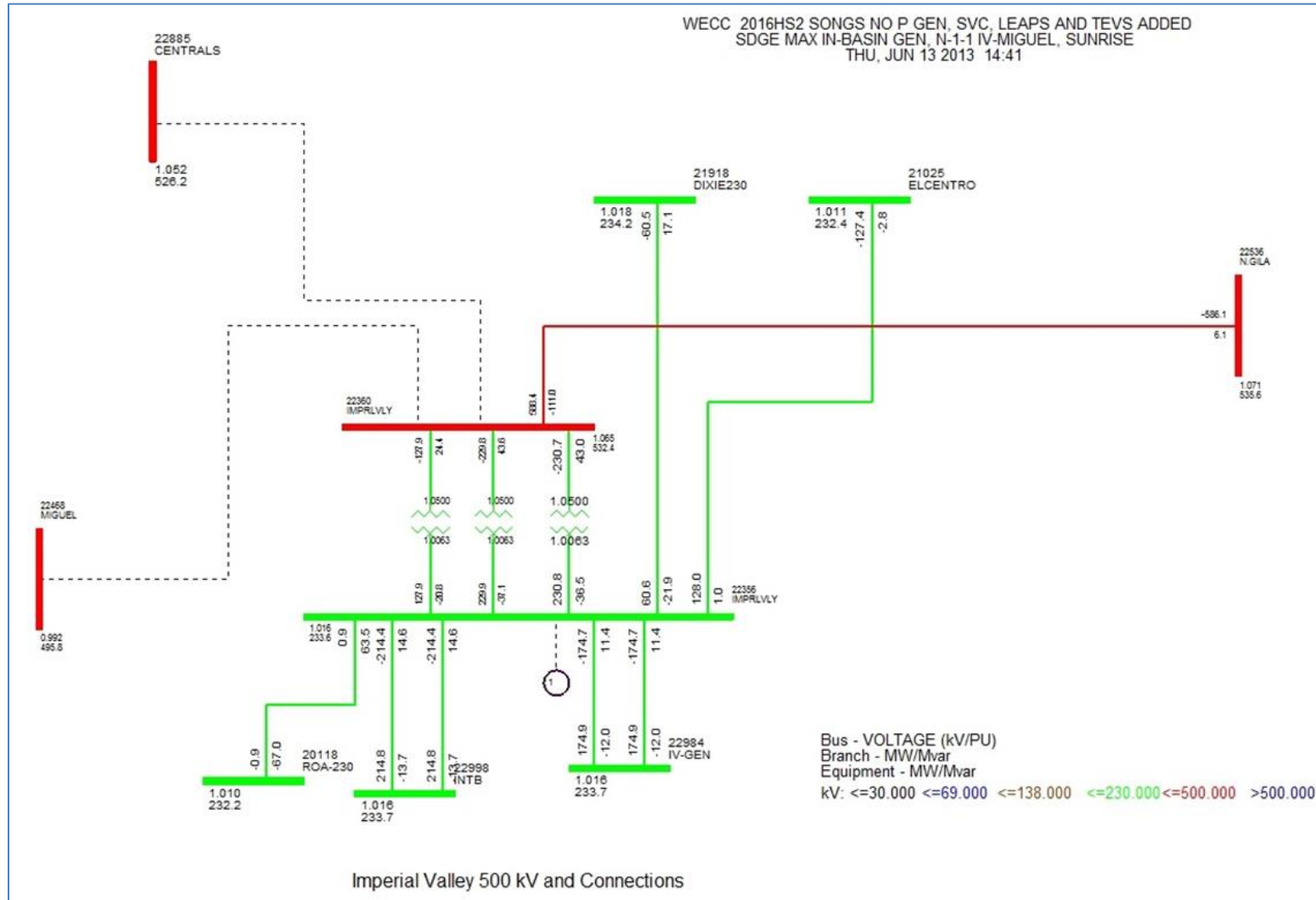


Figure 7 – N-1-1 with TE/VS Interconnect, IV Area



Note: All generation in the San Diego is assumed to be running.
Source: The Nevada Hydro Company

WECC 2016HS2 SONGS NO P GEN, SVC, LEAPS AND TEVS ADDED
SDGE MAX IN-BASIN GEN, N-1-1 IV-MIGUEL, SUNRISE
THU, JUN 13 2013 14:44

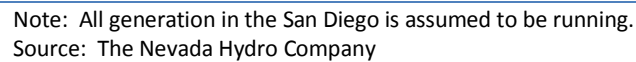


Figure 9 – WECC System Summary for SCE

WESTERN ELECTRICITY COORDINATING COUNCIL									
2023 HS1 BASE CASE									
***** SUMMARY FOR THE SUBSYSTEM SPECIFIED BY *****									
AREAS:									
24 SOCALIF									

AREA SWING BUS SUMMARY									
X----	AREA	-----X	X-----	SWING BUS	-----X	X----	ZONE	-----X	
#	X--	NAME	--X	BUS#	X--	NAME	--X	BASKV	#
24	SOCALIF			24004	ALAMT4	G		18.000	240
									SCE MAIN SYS
								119.3	
								83.3	
								370.0	
833	BUSES			338	PLANTS			276	MACHINES
154	LOADS			1101	BRANCHES			518	TRANSFORMERS
								33	FIXED SHUNTS
								0	DC LINES
								29	SWITCHED SHUNTS
								0	FACTS DEVICES
X----- ACTUAL -----X X----- NOMINAL -----X									
				MW		MVAR		MW	MVAR
FROM	GENERATION			18792.0		2972.1		18792.0	2972.1
TO	CONSTANT POWER LOAD			26240.9		-2182.8		26240.9	-2182.8
TO	CONSTANT CURRENT			0.0		0.0		0.0	0.0
TO	CONSTANT ADMITTANCE			0.0		0.0		0.0	0.0
TO	BUS SHUNT			0.0		-2924.4		0.0	-2834.8
TO	FACTS DEVICE SHUNT			0.0		0.0		0.0	0.0
TO	LINE SHUNT			0.0		582.1		0.0	523.0
FROM	LINE CHARGING			0.0		5197.7		0.0	4793.7
VOLTAGE X----- LOSSES -----X X-- LINE SHUNTS --X CHARGING									
LEVEL	BRANCHES			MW		MVAR		MW	MVAR
500.0	47			88.92		1481.54		0.0	496.0
230.0	252			234.12		3449.41		0.0	55.9
161.0	3			0.71		2.88		0.0	0.0
115.0	198			49.04		798.91		0.0	30.2
69.0	7			1.41		59.40		0.0	0.0
66.0	251			15.72		2778.62		0.0	0.0
55.0	4			0.09		0.70		0.0	0.0
34.5	30			0.93		39.74		0.0	0.0
33.5	2			0.00		0.31		0.0	0.0
33.0	9			0.00		71.82		0.0	0.0
26.0	2			0.00		151.97		0.0	0.0
22.0	9			0.00		227.57		0.0	0.0
20.0	5			0.00		307.83		0.0	0.0
19.5	2			2.72		102.04		0.0	0.0
18.0	16			1.86		371.92		0.0	0.0
16.5	4			0.18		23.83		0.0	0.0
16.0	6			1.04		62.71		0.0	0.0
15.0	6			0.00		95.83		0.0	0.0
14.4	8			0.00		77.01		0.0	0.0
13.8	167			1.24		679.31		0.0	0.0
13.2	4			0.00		10.09		0.0	0.0
12.5	1			0.00		0.00		0.0	0.0
12.5	6			0.00		0.00		0.0	0.0
12.0	9			0.00		0.51		0.0	0.0
11.5	1			0.00		0.66		0.0	0.0
11.0	2			0.00		0.00		0.0	0.0
7.2	4			0.00		1.95		0.0	0.0
6.9	12			0.79		17.75		0.0	0.0
4.8	1			0.00		0.45		0.0	0.0
4.2	2			0.00		0.00		0.0	0.0
2.3	1			0.00		1.63		0.0	0.0
2.2	2			0.00		0.00		0.0	0.0
1.0	9			0.00		12.05		0.0	0.0
0.7	1			0.00		6.48		0.0	0.0
0.6	2			0.00		0.00		0.0	0.0
0.6	1			0.00		0.00		0.0	0.0
0.5	15			0.00		0.00		0.0	0.0
TOTAL	1101			398.77		10834.91		0.0	582.1
								5197.7	

Source: WECC