Section 6: Transmission Line Routing

SECTION 6: ROUTING & CONSTRAINT MAPPING

6.1 SECTION PURPOSE

The purpose of this section is to present the transmission line routing process, including the identification of constraints, GIS data acquisition, and mapping that was necessary to support the routing process. Also discussed are the efforts completed to avoid constraints where possible and the evaluation matrix used to score alternatives relative to their constraint impact in order to establish the most viable routes for permitting, right of way acquisition, and construction.

6.2 ROUTING APPROACH

The routing of transmission line projects is most efficiently developed in sequential phases beginning with many potential route possibilities and narrowing to a few options. A team approach that incorporates GIS mapping, environmental permitting knowledge, survey expertise with the terrain, routing experience and knowledge of the region, transmission line design and construction, and consideration of political and current issues is critical. The unique issues of each region, area and route segment are used at each phase to help guide decisions to arrive at the preferred route.

Transmission line routing involves trade-offs among a variety of factors. The route options that are most promising balance environmental considerations with project need, constructability, current and future identified land use, project costs and specific electric system needs.

The Tri Sage team has brought specific team members together that bring this regional expertise to obtain the best possible outcome of the routing and siting process; i.e. "professional routing". The intent and benefit of professional routing of transmission lines is that, from the beginning of a project, crossings through overly difficult, potentially sensitive, and/or known "closed" areas can be eliminated. As a result, focus is put toward routing an alignment through areas that are known to be feasible, which ultimately reduces the burdens of permitting and acquiring of easements and/or rights-of-way later in the project. As a result, the preferred routes presented herein are intended to lead to a better overall project that is more acceptable to those who may be most impacted. Additionally, by taking into consideration the input received from key stakeholders, regulating agencies, and key utility and grid operators throughout the process, we be believe that we have arrived at project routes that are appropriate for the region, compliant with environmental regulations, and constructible.

6.2.1 Routing Process Overview

Upon identification of the project scope, an electric grid evaluation was performed, as discussed in Section 5, to establish termination points and line voltages. Line voltage in turn is a primary variable in selecting structure types. Once line voltage and structure type(s) were determined, a right-of-way (ROW) width could be assumed. Structure types and required ROW will ultimately drive line route possibilities. Generally speaking, there is more flexibility in routing transmission lines for voltages < 120kV than there is in routing higher voltage lines.

With termination points, voltages, preliminary structure types and required ROW widths determined, the next step was to identify study areas between the chosen termination points on base GIS mapping.

A straight line alignment between termination points rarely results in an acceptable route. Therefore, the study area delineated should be large enough in size to contain all possible route alternatives. Typically, longer project lengths (100 miles or more in length) will require large study areas; shorter project lengths may require smaller study areas. For longer project lengths, study area delineation and preliminary line routing is typically done on mapping at a 1:500,000 (1" = ~7.891 miles) scale. For shorter length projects, one could begin with 1:24,000 (1" = ~0.378 miles) scale mapping to begin route selection studies. For this project, 1:100,000 scale mapping was used for this stage of the routing development.

Once all possible route alternatives are identified, larger scale mapping (1:250,000 and possibly 1:24,000 scale) is used to fine-tune preferred routes. For this project, 1:24,000 scale maps were used to fine tune the proposed line routes. Most routing efforts are considered complete at this stage of the process.

After fine-tuning of preferred routes was completed at the 1:24,000 map scale, the project team chose to further refine the routes by reviewing them against digital aerial photography in an attempt to identify any 'fatal flaws' that may exist along the chosen routes. This is a beneficial step particularly if the aerial photography is more up-to-date than the 1:24,000 scale paper mapping that was used.

Helicopter reconnaissance was then performed in areas of significant concern (i.e. areas congested by terrain, other facilities, potential environmental constraints, etc.) to even further refine the proposed routes that had been laid out on paper. In this step, GPS technology was used to better locate specific elements, such as angle points, along the alignment. For this project, each proposed angle point has a GPS coordinate. After helicopter reconnaissance, on-ground staking of the preferred route(s) would be the next step, which is beyond the current scope of this project.

6.2.2 GIS Methodology

In order to support the routing process, extensive mapping was necessary to provide both preliminary information for routing avoidance, as well as follow-up mapping to capture the land and environmental constraints. Specific Geographic Information Systems (GIS) mapping was created and used to identify specific constrains of avoidance.

The first step in the mapping methodology was to establish baseline maps based on the establishment of the preliminary corridors. The methodology used was to identify the key factors or GIS layers to be considered as constraints (or opportunities) throughout the routing process. The project team focused on the key factors that would influence the "routability" of the lines through particular lands such as federally managed or private land, or the presence of limiting environmental conditions such as wetlands, wildlife, etc.

The factors used to develop the constraint maps, which are discussed in greater detail herein, included:

- Land Status / Ownership (Public vs Private)
- Topography and Slopes
- Roadways and Roadway Crossings
- Stream Crossings
- Railroad Crossings
- Wetlands
- Areas of Critical Environmental Concern
- Desert Tortoise and Sage Grouse Habitat
- Herd Management Areas
- Existing Utilities and Utility Crossings
- Wilderness Areas and Wilderness Study Areas
- Vegetation

The GIS digital data coverage for each constraint was merged together and edited to create a set of homogeneous items between the three state offices of the various agencies from which data was used. Elevation data was also researched and collected. This elevation data was converted to grid. A grid is a representation of the area as a series of equally sized cells or pixels. The GIS data and the elevation grids were then combined in the GIS software to create composite maps to aid in the evaluation of viable routing segments.

Initially, maps with constraints were developed at the 1:100,000 scale. This information was used to develop preliminary routes. Once preliminary route segments were established, maps were then narrowed to reflect the specific segments with the constraint overlays applied to layers. From this point, a weighted matrix evaluation was completed to narrow the segments even further to allow final preferred route selection. This matrix is further discussed in Section 6.5. It should be noted that this analysis was performed at the planning level and does not include localized site specific factors that could influence final design level engineering and permitting. Nor does this analysis account for private land owner's willingness to allow easement crossings.

6.3 GIS CONSTRAINT MAPPING

The specific preliminary corridor alignment details were input into a GIS database. This allowed the GIS constraint mapping and analysis to begin. Multiple layers of constraints were researched and overlaid onto the routing maps. These layers were overlaid together through the GIS mapping software, but required quality control with regard to completeness. Due to the multiple sources of information pertaining to each constraint, multiple databases were researched, agency contacts were made, and quality review of the data was completed. Much data was eliminated due to level of completeness or receipt from non-qualified resources. Each resource that was mapped as a routing constraint is discussed below.

6.3.1 Land Status / Ownership

Land status mapping is one of the critical elements of the mapping and provides the basis for how routing proceeds. In general, it is desirable to route transmission lines on Public Lands to avoid the economic and social impact of locating transmission lines on private land, thus reducing the potential for expensive and time consuming condemnation proceedings. It is critical at this point to understand that condemnation is a legal right given to utilities operating in the respective regions to ensure that a given private land owner cannot hold the utility hostage during the routing of transmission and distribution lines that benefit the public. As the industry has changed over the past years to include merchant transmission lines, this right of condemnation has become an issue for consideration. General merchant line owners are not afforded the same right of condemnation. As such, many privately owned transmission lines are partnered with local utilities to bring condemnation rights into the project. This issue is discussed in next steps but is also critical at this point to understand that the evaluation of constraints has assumed that these projects will have the benefit of condemnation. However, routing has still been completed to avoid private lands. This is necessary due to the history of many projects that are held up in time and cost even with condemnation rights. It is not always possible to totally avoid private land ownership, but avoidance is one key to line routing. Note that there are times when private land is desirable as is the case on small lines where the private land owner(s) are willing participations. That is not the case here.

To identify private from public lands, this level of mapping shows all the land managed by public land agencies: Bureau of Land Management (BLM), US forest Service (USFS), State Lands, National Parks, Bureau of Indian Affairs (BIA), along with other federal and state ownerships. This also includes privately held land ownerships, but does not go to the level of specific private parcel ownership determination as that will be conducted following final line routing.

The BLM land status coverage is managed through individual BLM state offices. For this reason, much of the available mapping from this agency is unique to each state, often resulting in different types of land categories that are tracked. For example, California BLM does not track privately owned parcels but instead, categorizes these parcels and others into one ownership classification of "unclassified", but Nevada and Utah do track private parcel ownership. The result is a different set of items in both type and naming nomenclature for each state. This was addressed in the mapping process by creating similar categories in each database to be label and color coded to allow for common identification throughout the maps. Land ownership was then mapped at a 1:100,000 scale, providing planning sheets that included land status, topography and jurisdictional boundaries (military bases, fee lands, etc.). From these sheets, covering vast areas of land, the routing was initiated and multiple route segments were identified.

Included within this land mapping was ownership by the Bureau of Indian Affairs. This land is owned by tribal communities that typically involve cultural, religious or other sensitive criteria and are typically avoided where possible. Specific to the northern route within this report, BIA land is crossed as one of the viable route segments. In this case, there is belief that the BIA may have interest in development of its own renewable energy resource on this land. The addition of transmission infrastructure may pose a beneficial opportunity in this case and was considered as a viable route.

6.3.2 Topography and Slopes

Topography is a fundamental component to transmission line routing. This, along with evaluation of slopes is necessary to optimize both the line route and structure placement. In order to support both routing and conceptual design, the team utilized the National Elevation Dataset (NED). This is a grid set of three dimensional gridlines that details topography from the USGS 1:24,000 quadrangle mapping. This data was then used with ESRI's ArcMap spatial analysis software management to create digital elevation models and allow for integration of the specific route segments. This integrated topographic overlay with the routing allowed for the reporting of specific slope ranges from 0 to 9%, 10% to 18%, and above 18% (18% to be considered extreme sloping) and applied this to the routing to allow for evaluation of extreme conditions and modifications of the routing where necessary. Once finalized, mileages and acreages of potential right of way of routes within specific slope ranges were calculated and applied to the weighted matrix. Slopes are important to identify flat low land verses hillsides which may require transmission line structure modifications. For example, flat lands with alluvial fanning may indicate drainage concerns while steep areas can be technically difficult to develop or construct. In most cases, extreme slopes will indicate a need for extensive roadway cutting in order to reach those transmission structures. For most of the routing on this project, extreme terrain was avoided. This topography and slope information was used, along with the land status mapping, as the basis of the land database from which all other constraints were applied.

6.3.3 Roadways, Trails and Roadway Crossings

Roadways and access ways are a critical component in routing transmission lines. Typically, agencies wish to utilize existing roadways where possible. Some public land management agencies even regulate the use of existing dirt two track roadways. As such, it was critical to identify all the roadways including highways, US interstates, paved public local roads, two track trails and access ways. This information, when identified up front on the corridor mapping, assists in the routing of lines adjacent to, or close to, these existing roads. To accomplish this, the US Census Bureau Tiger Database was used to identify roadways in the vicinity of viable route segments. Roadways identified within this database were at the USGS 1:24,000 quadrangle series mapping level. This included any identifiable roadway down to a two track dirt road. Roadways were classified as ones viable for use for construction. If the access was identified within 100 feet of the proposed route, the weighting was established as excellent; between 100 feet and one half mile (2640 feet) the weighting was established as good; and greater than one half mile the weighting was established as poor.

Issues that were accounted for in both the routing and evaluation matrix weighting includes distance from an existing roadway, requirements for new roadways, possibility of overland travel during construction, requirements for spur roadways for structure construction and roadway upgrades.

Roadway crossings were also mapped and weighted in the evaluation as such crossings will require additional structural design to accommodate wire clearances and specific crossing permits will also likely be required. This was all accounted for to arrive at the preferred routing evaluation and costing data.

6.3.4 Stream Crossings

The Federal Clean Water Act requires regulation of water bodies and stream water quality. As such, stream impacts must be either avoided or closely managed during transmission line construction. In order to assist in the avoidance of stream impacts, GIS datasets from the Tiger Files were obtained and mapped. The initial information was sourced from the USGS 1:24,000 series quadrangles.

While impacts to large drainage areas were avoided, some stream crossings will be required. These were identified to allow for the conceptual design and estimating necessary to account for such crossings. Crossing permits will also be required and were therefore documented and weighted.

6.3.5 Railroad Crossings

Railroad crossings were also mapped and weighted in the evaluation as such crossings will require additional structural design to accommodate wire clearances and specific crossing permits will also be required. This is all accounted for to arrive at the preferred routing evaluation and costing data. Specific to the three routes identified, there are only two railroad crossings, both of which are located on the northern route. While it is beneficial to avoid railroad crossings, it should be noted that railroads also offer a benefit to projects when it comes to material deliveries. In the case of the north route, this will provide both a constraint for design and permitting, but will also offer additional flexibility for material deliveries.

6.3.6 Wetlands

Wetlands are managed through the US Fish and Wildlife Service, and information specific to the identification and classification of these resources is managed under the National Wetland Inventory database. The Army Corps of Engineers manages the impacts to wetlands and how mitigation will be applied to protect these resources.

The mapping team obtained the set of GIS data from the National Wetland Inventory specific to the routing corridors. This information was downloaded into a GIS layer of the routing to allow for avoidance where possible. In addition to the potential environmental impacts, wetlands affect the foundation design and constructability of transmission lines and are avoided wherever possible. Two wetlands, however, will be impacted by this project. Specifically, the Owens Valley and the Humboldt River will have crossings of the power lines which will require diligent design, significant permitting, and careful construction to complete.

6.3.7 Areas of Critical Environmental Concern

This criterion is a summary of resource areas managed by the Bureau of Land Management that are considered environmentally sensitive areas. Management of this "collective" resource began as the 1976 Federal Land Policy and Management Act (FLPMA). This act directs the BLM to protect the riparian corridors, threatened and endangered species, cultural and archeological resources, and unique scenic landscape. Management of these resources is at the BLM's discretion and are identified, mapped and controlled solely within each State's BLM agency. This information is available in GIS format and was obtained for reference in the NEAC mapping process. It was included as a constraint level in the mapping; was avoided were possible; and weighted in the evaluation where not avoided completely.

6.3.8 Desert Tortoise and Sage Grouse Habitat

These two species have been identified as special management resources within Nevada and require special attention with regard to impacts. While not established as a Threatened and Endangered Species, both resources are highly monitored and protected with special status in Nevada. As such, the US Fish and Wildlife Service provides the tracking necessary to support the Nevada directive of special status monitoring. The data bases managed by the USFWS were referenced during the mapping and constraints determination process. It should be noted that in addition to the USFWS database, review was completed of the Nevada Department of Wildlife (NDOW) database as well.

The Desert Tortoise Habitat is primarily found in Southern Nevada. As a result, routing was completed to avoid these habitat areas for the southern route segments. The Eastern and Northern routes did not come near the tortuous habitat.

The Sage Grouse is located primarily in the Northern Nevada, Western Utah and Sierra Nevada Mountain Ranges. As a result, all three routes (North, South and East) came into contact with this habitat area. Much was avoided, but due to the large expanse of habitat, total avoidance was not feasible. The Greater Sage-Grouse is a sensitive Nevada resource that will require attention in the next phases of this project.

In August 2008, the NDOW contracted Resource Concepts, Inc to study the potential impacts of energy development on greater sage-grouse (Centrocercus urophasianus) and their habitat. In an effort to determine the possible extent and location of potential impact areas, they conducted an inventory of renewable and non-renewable energy development in Nevada in relation to sage-grouse distributions and known strutting grounds (leks). The results were presented in a final report dated August 2008. Information contained in that report was referenced during the routing of these projects but was not detailed for confidentiality purposes and in conformance with protection of this resource. This report acknowledges that the Greater Sage-Grouse is critical to the State and moving forward, the project proponent will actively work with BLM and NDOW during the application phase of this project to establish the lek and habitat sites and associated mitigation.

It should be noted that while these two critical habitats were specifically mapped and avoided where possible, there are multiple other habitats that will require investigation. However these two are specifically tracked by the governmental agencies while the majority of the others will be field identified during the NEPA and CEQA environmental field investigations.

6.3.9 Herd Management Areas

The Wild Horse and Bureau Act of 1971 dedicated large expanses of land within both Nevada and California as Herd Management Areas. Each one of these areas has designated criteria that define the size of herd, as well as sensitivity of the habitat and environment. As such, these areas were critical to identify and avoid if possible. These areas are managed by BLM and are mapped within their database. Information was downloaded into the GIS layers and for routing that could not avoid this land classification, a calculation was completed to identify the area of disturbance within each segment of line route. This acreage was then given a weighting based on the amount of habitat impacted.

6.3.10 Existing Utilities and Utility Crossings

Existing utilities are critical to review during the routing of transmission lines for a twofold purpose; first it is important to identify existing utilities as an opportunity to utilize existing utility corridors where possible, and second it is critical to avoid utility crossings if possible.

Established utility corridors are areas designated by federal, state, and/or local planning agencies as appropriate or suitable for existing and future utility infrastructure. While there are thousands of miles of existing utility corridors that lend themselves well to new transmission line construction, much of these are either limited by land constraints such as terrain, or they are electrically constrained and do not allow the new grid connections that are required to complete necessary new grid expansions.

Specific to this project, existing utility corridors were paralleled where possible. However, many of the existing corridors did not lend themselves to the new routing that is required as discussed in Section 4 of this report. The identification of new utility corridors and infrastructure on federal land will be an important element in allowing Nevada to continue to economically and reliably develop the transmission infrastructure necessary to support the export of renewable energy. Note that due to the extensive nature of existing utilities, and the multiple impacts and benefits to paralleling these facilities, existing utilities were not included in the evaluation matrix.

Mapping of the known Nevada, California and other western states corridors were obtained from the specific state's BLM Master Title Platts (MTPs). This information was then digitized to obtain every utility right of way found. This information not only assisted in the routing within or near corridors, but also allowed for the determination of line crossings that will be required and ultimately the determination of utility crossing permits that will be necessary. These crossings were accounted for in the evaluation matrix.

6.3.11 Wilderness Areas and Wilderness Study Areas

Mapping of Wilderness Areas (WA's) and Wilderness Study Areas (WSA's) was obtained from each State's respective BLM office. Due to the environmental sensitivity of these areas, routing of the transmission line alternatives was completed to avoid them. Because they are highly sensitive, however, they were also included in the weighting if the line route came within one half mile of a WA or WSA.

6.3.12 Vegetation

Vegetation mapping was obtained from ESRI's DCW data. While the majority of the route segments cross rangeland with little or no mapped vegetation, some instances of shrub and scrub lands are crossed that could impede travel and/or construction activities and could require tree trimming. These areas were included in the evaluation matrix. Much of the growth in these areas is juniper and pinion. In some instances, the lines traverse near Joshua trees which are threatened and endangered species. All threatened and endangered vegetation will be identified during the field investigations by biologists during the NEPA and CEQA permitting process.

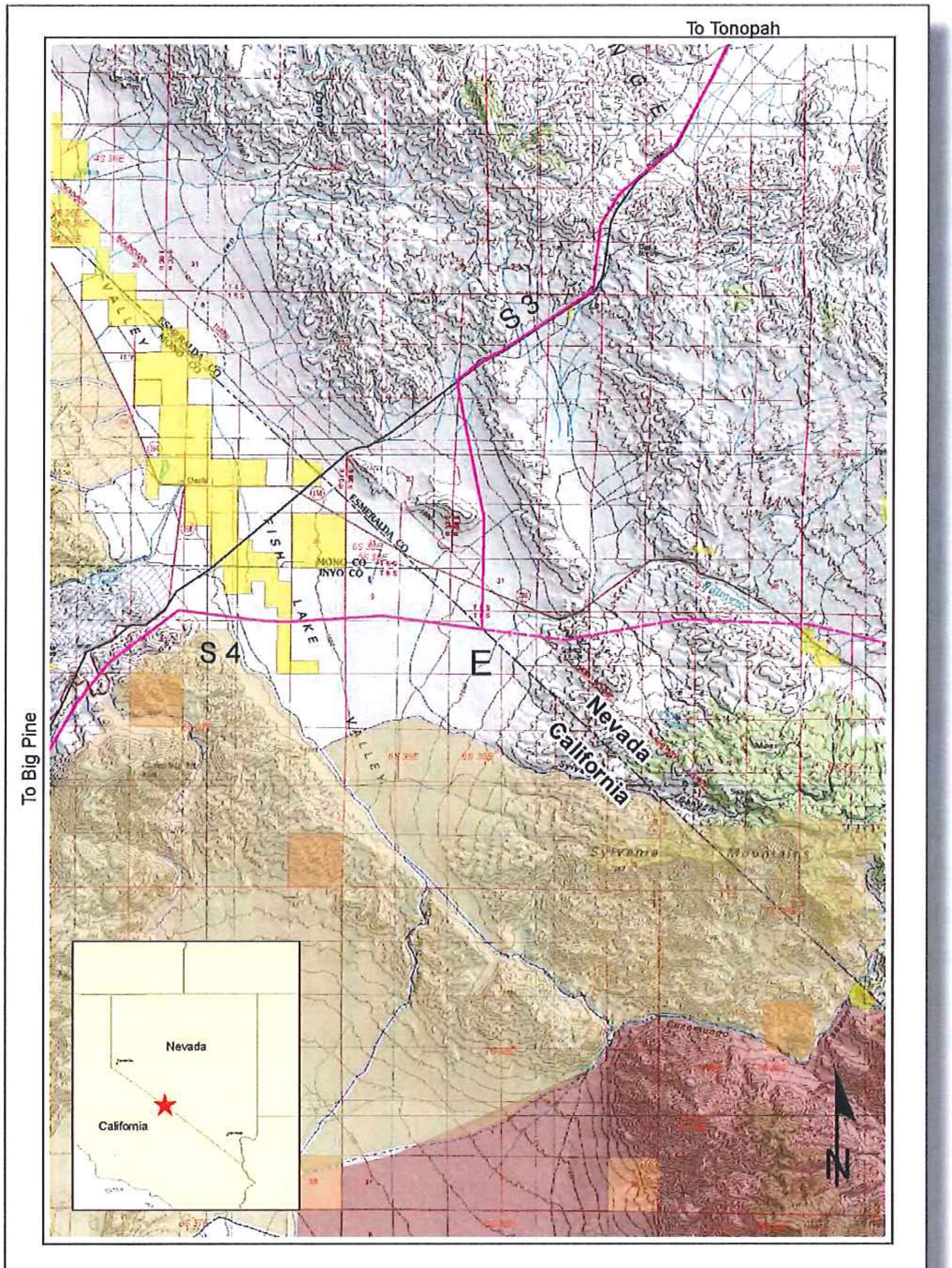


Figure 6.1 – Representation of a Constraints Map (example of South Project at Border)

The following presents the routing analysis that was completed, including considerations and issues that were addressed resulting in the three proposed transmission export projects; and the evaluation matrix that was used to narrow the segment alternatives into the preferred routes.

6.4 ROUTING ANALYSIS

The process of locating transmission access for renewable energy export from the Nevada to the California electric grid began with the identification of all known constraints along the approximately 617-mile border between the two states. The effort required to perform this work is extensive and was discussed in greater detail in Section 6.3, GIS Constraint Mapping. The team's research into the location of available transmission line export corridors along the Nevada-California state line identified several significant constraint issues, which effectively limit the location of transmission export lines. The following *Figure 6.2 – Nevada-California Border Constraints Map*, is a compilation of all the constraints identified within Nevada and California and along the state border that could pose potential impacts to the ultimate routing and permitting of the transmission export projects.

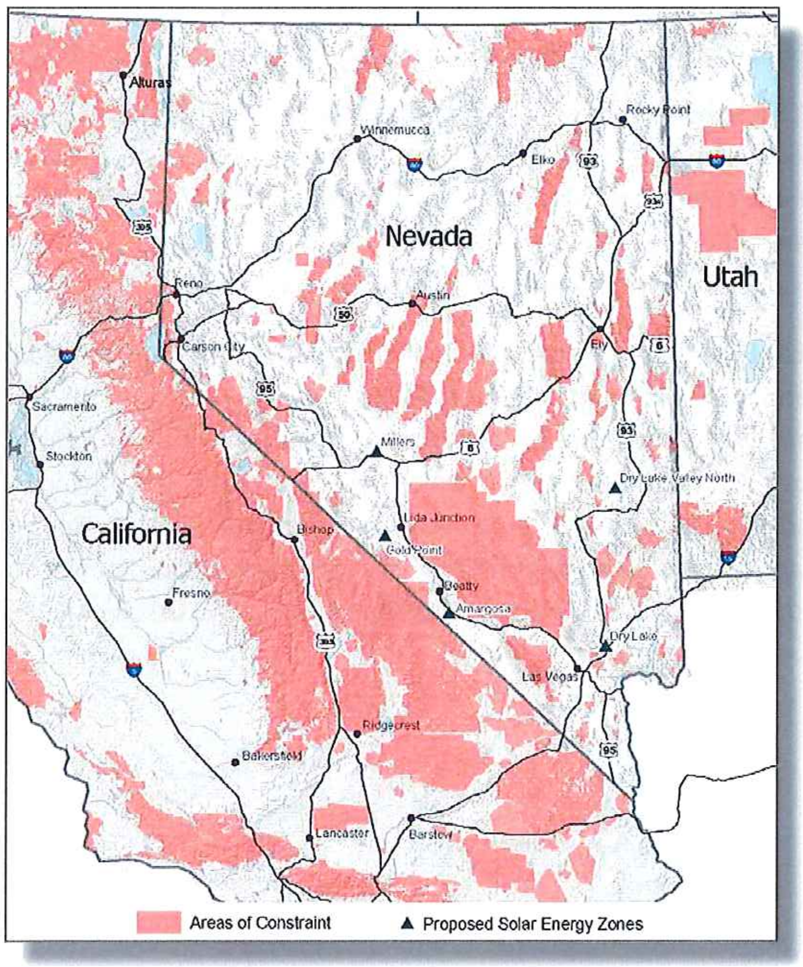


Figure 6.2 – Nevada-California Border Constraints Map

The constraints identified along the Nevada-California border consist of:

- Twelve (12) national forests, resulting in approximately 505 miles of length along the state line, several with contiguous borders.
- Sixteen (16) wilderness/wilderness study areas, resulting in approximately 270 miles of length along the state line.
- Nine (9) national parks/national monuments, which result in approximately 240 miles of length along the state line. The Lake Tahoe Basin is not identified as a national park or monument; however, the 'Basin' is a significant environmental and recreation resource.
- Five (5) military reservations, which result in approximately 145 miles of length along the state line. Three of these are of significant size and are located in the Mohave Desert area of Southern California.
- Eight (8) state game refuges, with approximately 60 miles of length along the state line.
- Eighteen (18) significant mountains and mountain ranges, primarily located on the California side of the state line. A linear mileage count of mountains and mountain ranges that exist along the state line is near impossible to determine by way of mapping. One can see their significance however on the above Figure 17, and on other topographical figures, maps and exhibits throughout the report.

In the initial process of identifying feasible and constructible transmission export routes from Nevada to California, all known possible crossings over the state border from Nevada into California were analyzed. From this evaluation, the team arrived at nine (9) possible ways to route from Nevada to California, one of which does not cross the Nevada-California state border; each is indicated on *Figure 6.3 – Nevada-to-California Preliminary Routes*. These routes were evaluated against the identified constraints – physical, environmental, political, and/or social, as well as the electric grid limitations and opportunities discussed previously in Section 5.

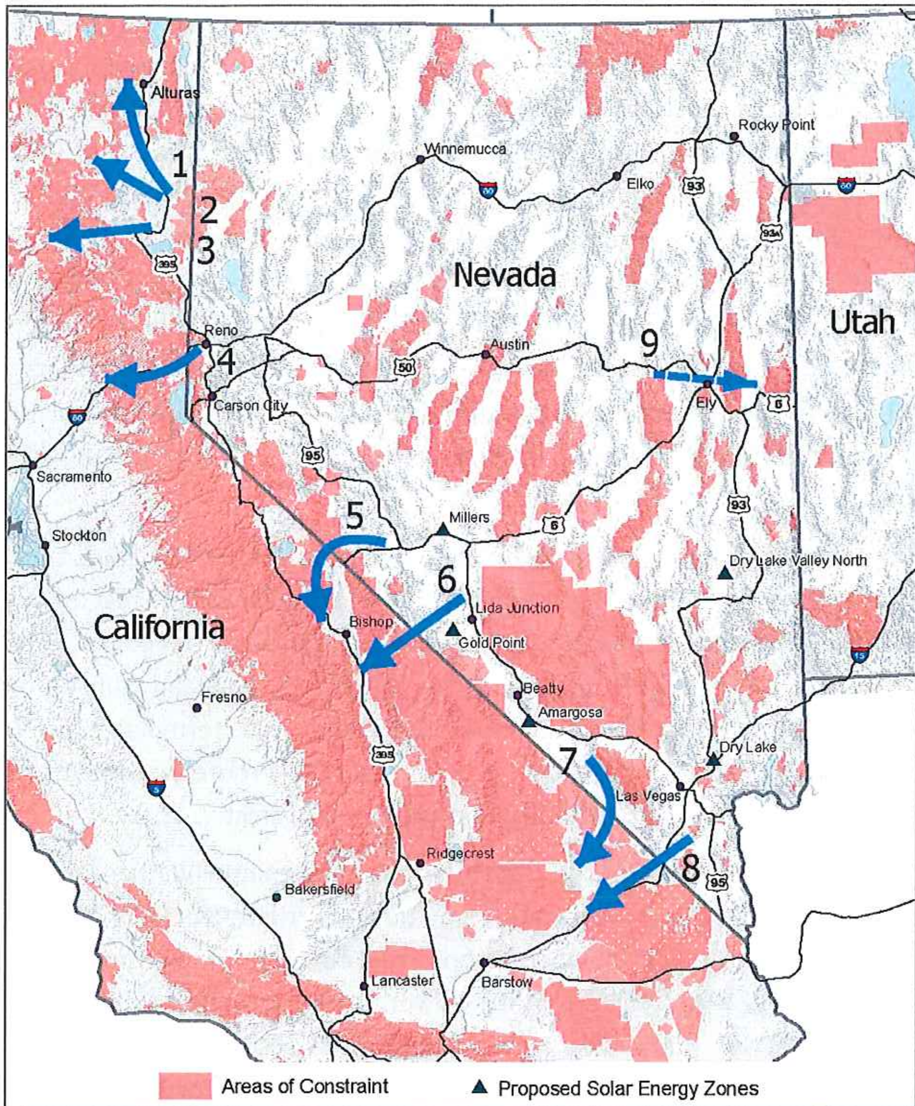


Figure 6.3 – Nevada-to-California Preliminary Routes

Following are the nine (9) route opportunities that were considered and evaluated:

1. The first crossing possibility would utilize the existing NVE 345kV 'Alturas' transmission line that originates at Tracy Power Plant, located east of Reno, Nevada, and terminates at Hilltop Substation, just north of Alturas in northern California. The Alturas Line, and therefore the corridor in which it is located, already connects the NVE system with Bonneville Power Administration in the Modoc County, California area. However, constructing another parallel transmission line within this corridor would not relieve congestion into the Central California grid, due to capacity limitations at Hilltop Substation.

2. The second crossing possibility would also utilize the existing NVE Alturas Line corridor, beginning at a previously proposed new substation, Raven, continuing westward to Round Mountain, California, approximately 30 miles northeast of Redding, California. In 2008 the TANC (Transmission Agency of Northern California) Transmission Plan, consisting of the development of four major high-voltage transmission projects in northern California, was introduced. The backbone of the overall project included two new 500 kV lines (Zeta North and Zeta South) to be constructed, beginning at the proposed Raven Substation and terminating south at Tracy, California. Due to significant opposition from the residents primarily located in Shasta and Tehama Counties, California, the whole project was halted in 2009. As a result, this area is viewed as a limited-viable corridor for new transmission, due to the very strong political and social constraints.

3. The third crossing possibility takes advantage of LMUD's (Lassen Municipal Utility District) planned double-circuit 230kV project, intended to provide an east / west interconnection to accommodate various proposed renewable energy generation projects within LMUD's service territory. The project begins at the proposed Viewland Substation, located approximately 10 miles north of Wendel, California, and terminates in Westwood, California, approximately 20 miles west of Susanville. This route was identified as viable but contingent largely on the LMUD progress with their project.

4. The fourth possibility, the proposed Great Basin underground HVDC project, follows the existing Interstate 80 (I-80) transportation and utility corridor, from the NVE Tracy Power Plant east of Reno, Nevada, through Reno, Truckee, Auburn, Sacramento and Davis, California to the WAPA (Western Area Power Administration) O'Banion Substation, located southwest of Yuba City. This crossing is associated with many difficult environmental constraints, such as the 'scenic corridor' status of Interstate 80, and the protections in place for the Tahoe National Forests. This route could potentially be considered for a future overhead transmission project in the event of the HVDC project not proceeding. In order to not replicate the intended use of the planned HVDC underground project, and in compliance with the contract directive to not duplicate effort, this route was not considered at this time.

5. The fifth possibility for crossing from southern Nevada into California is at Montgomery Pass. This is a crossing near US Highway 6 that makes its way between, though does not cross through, Toiyabe National Forest to the north and Inyo National Forest to the south. This was identified as a strong opportunity for new routing into California.

6. The sixth routing possibility into California traverses the southern Nevada-California border via Fish Lake Valley and Deep Springs Valley. Upon entering California, the

opportunity continues in a southeasterly direction to Big Pine, California. This crossing was also considered a strong opportunity for this project.

7. Crossing possibility seven which begins in Pahrump, Nevada and terminates in southern California was found to be constrained by a number of established BLM Wilderness and Wilderness Study Areas. For this reason, this crossing and route was determined to have limited feasibility.
8. The eighth crossing possibility that was identified during this project would utilize the AC/DC power line corridor, beginning at the Eldorado Substation located south of Boulder City, Nevada. This crossing/route possibility is already greatly constrained in terms of available electrical capacity, and therefore was not determined to be a feasible opportunity for this project.
9. The ninth and final possibility evaluated for getting from Nevada to California utilizes an existing transmission corridor from eastern Nevada to the Intermountain Power Project (IPP) in central Utah. From this point, Southern California is accessed by way of the existing AC/DC power line corridor. While this route is constrained as discussed in opportunity 8 above, there was consideration in that by heading east to reach this AC/DC corridor, a route could be established that would avoid all the physical congestion in and around the Eldorado Substation, but could potentially take advantage of available capacity that is freed up from reduced sales of coal generated power. Therefore, this option was established as viable.

From the preliminary evaluation, the team narrowed the focus to crossings at locations 3, 5, 6 and 9 from the above discussion. The following discussion details these route evaluations as the East Route, North Route, and South Route. As discussed in Section 5, these three routes were also evaluated in regard to potential impacts to these projects both with and without the NVE RTI effort. These routes, along with all associated route alternatives, and supplemental routing required in the absence of the NVE RTI are presented in *Figure 6.4 – Routing Alternatives and Line Segments*. Each route is broken into line segments which were used for the ultimate matrix evaluation of the route options and selection of the final preferred route.

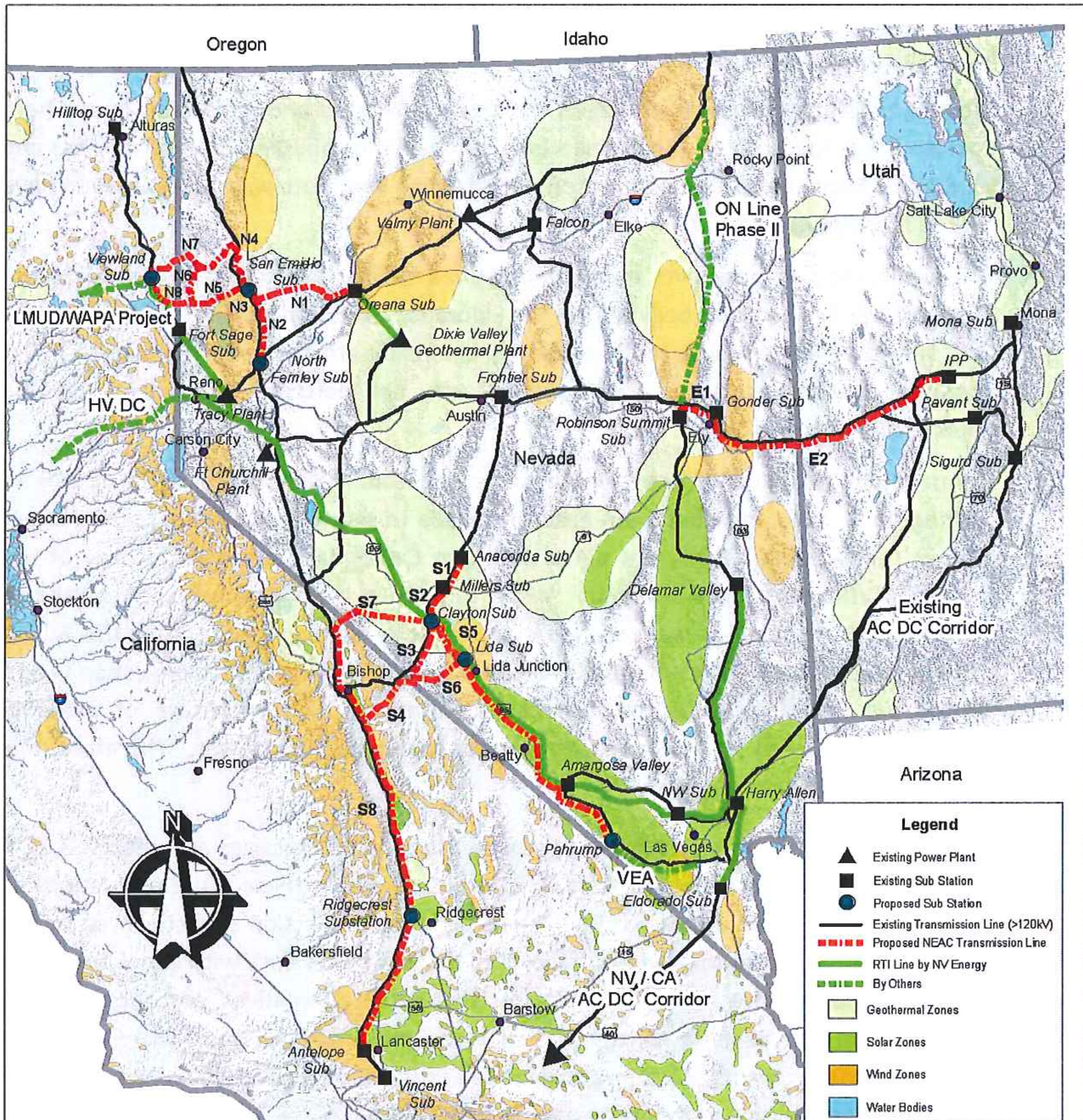


Figure 6.4 – Routing Alternatives and Line Segments

6.5 ROUTE SUMMARIES

6.5.1 North Route Details

The North Route provides interconnection into California by way of a 345kV line from NV Energy's Oreana Substation or a new substation at North Fernley to a new substation north of the Sierra Army Depot in Herlong, California.

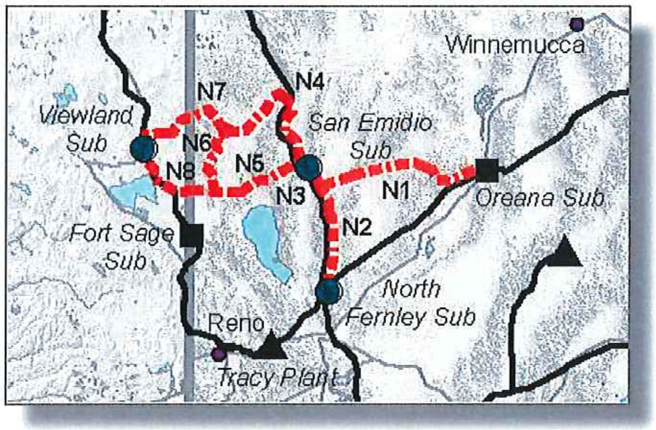


Figure 6.5 – North Route with Line Segments

6.5.2 East Route Details

The East Route, which could be either 345kV or 500kV, provides interconnection into the California market by connecting NV Energy's Robinson Summit Substation to IPP, thereby connecting into the AC/DC north-south corridor to southern California.

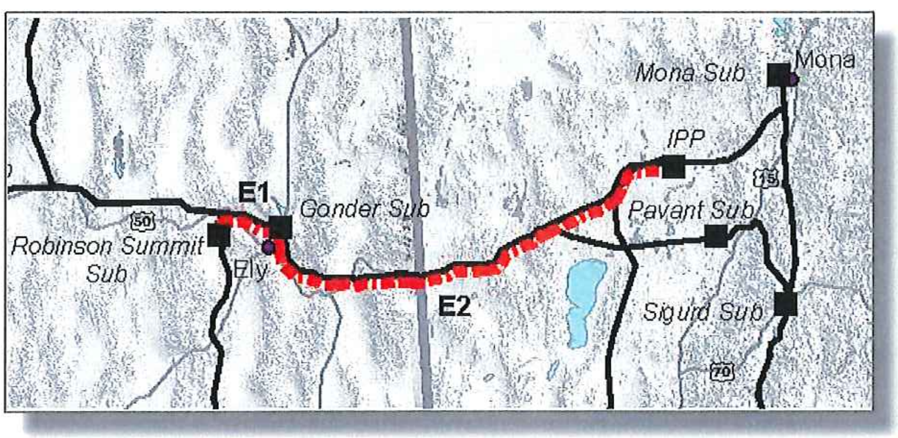


Figure 6.6 – East Route with Line Segments

6.5.3 South Route Details

The South Route, proposed to be 500kV, provides interconnection into the California Market at the CAISO operated Antelope Substation, located in Lancaster, Southern California. This route has several identified alternatives and is shown in *Figure 6.7 – South Route with Line Segments*.

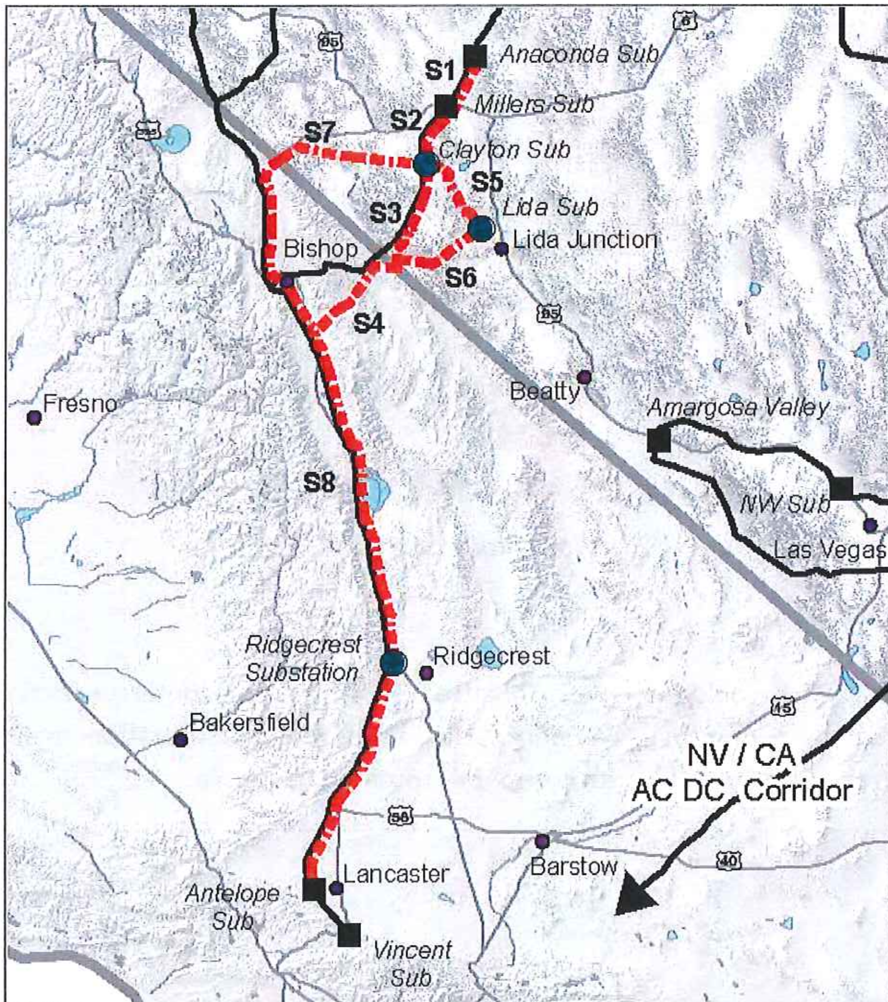


Figure 6.7 – South Route with Line Segments

6.6 EVALUATION MATRIX

Each of the constraints listed in Section 6.2 are critical for transmission line routing. To capture each of these constraints, they were quantified from the GIS database and input to an evaluation matrix as discussed in Section 6.3. The various line segments were combined into route options for evaluation against each other in order to select the preferred route.

The score derived for each route option indicates the level of difficulty associated with completing the project. A normal weighted score of 100 was assigned and based on the associated constraints; the score for a specific route was calculated. For example, a line route alternative that crosses a section of wetlands would receive a lower score than one that does not cross a wetland. Every effort was made to make the scores objective rather than subjective such that they are all based on quantifiable data and calculations.

The evaluation matrix was weighted by three major criteria (Permitting, Right of Way Acquisition, and Constructability) and each route alternative was scored based on the GIS data in accordance with the following discussion.

6.6.1 Permitting

Permitting is considered the most critical component for evaluating the viability of a project. A project that cannot be permitted cannot be built. For this reason, permitting was given 50% of the weight in the constraint evaluation matrix. The line routes were selected such that they are all considered permitable, but some impact various constraints more than others and the matrix provides a quantifiable method of comparing the various alternatives.

The constraints that make up the permitting criteria are Wilderness Areas and Wilderness Study Areas, Fish & Game Critical Habitat, Herd Management Areas, Wetlands, and Areas of Critical Environmental Concern. Each of these constraints was given equal weighting (considered equally important) and their raw score was based on the area (acres) impacted by the line route. An additional factor for CEQA permitting was also included in this category but was given a smaller weighting in recognition that many of the same environmental issues drive the NEPA and CEQA permitting processes.

6.6.2 Right-of-Way Acquisition

Right of Way Acquisition was given a lower weighting than Permitting (30%) given that issues associated with right of way acquisition can be resolved through negotiation, minor reroutes or design modifications, or, as a last resort, condemnation if the right of eminent domain is available to the ultimate project owner.

The constraints associated with right of way acquisition are based on land status. Private land and Bureau of Indian Affairs (BIA) land were given the highest weighting in recognition that they are normally the most difficult to negotiate. State and Military land were given a lesser weighting and Crossings (the acquisition of crossing permits) were given the least weighting. Scoring was based on the area (acres) of land impacted.

6.6.3 Constructability

Constructability was given the lowest weighting (20%) in recognition that the routing was completed such that all of the routes were chosen with constructability in mind and any issues encountered can be dealt with through thoughtful engineering.

The constraints associated with Constructability are physical in nature. Existing Access and Slope were given the highest weightings based on potential long term impacts to the environment. Wetlands were also given a higher weighting to account for any special construction techniques that may be required in these areas. Vegetation and Stream Crossings were assigned a slightly lesser rating given that impacts will be mitigated during construction and restoration activities would be required.

6.6.4 Matrix Evaluation Results

The evaluation matrix results for the preferred route options are summarized in *Table 6.1* – Evaluation *Matrix Preferred Routes Summary*. Detailed results for each of the route options considered are included in subsequent Tables 6.2 to 6.6. These Tables can be found at the end of the Section. As previously discussed, the route option receiving the highest score for the project alternative being considered became the preferred option.

For the North Project, the preferred route is Option 3 with Oreana as the beginning terminus, as discussed in Section 5. This route is made up of Segments N1+N3+N5+N8 as shown in Figure 6.8 – Preferred North Route (Project).

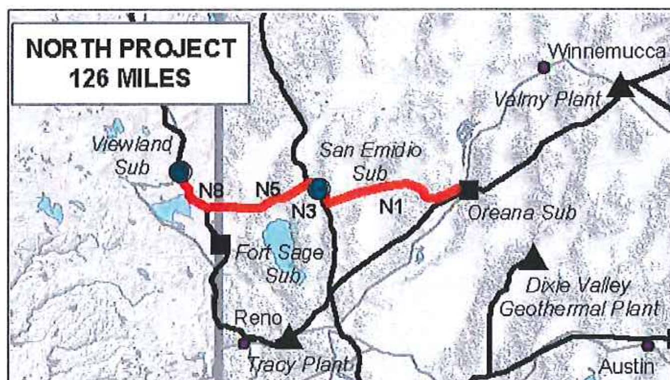


Figure 6.8 – Preferred North Route (Project)

If North Fernley had been the preferred beginning terminus, Option 7 would have been the preferred route. This route is made up of Segments N2+N3+N5+N8 (not shown).

For the East Project, the preferred alternative is either Option 9 or Option 10, depending on the voltage of the line, as discussed in Section 5. Both of these Options are made up of Segments E1+E2, as shown in *Figure 6.9 – Preferred East Route (Project)*.

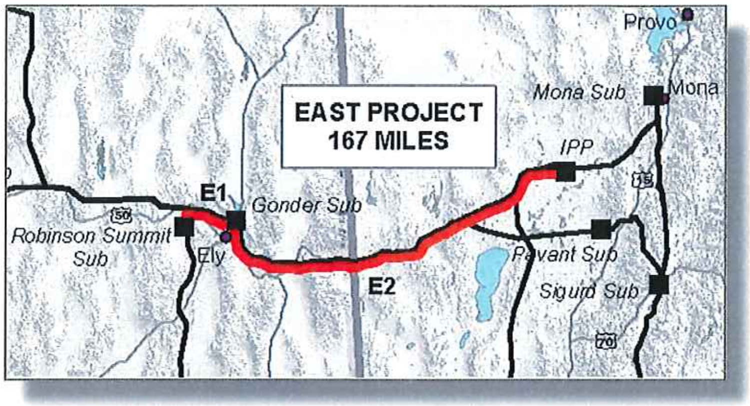


Figure 6.9 – Preferred East Route (Project)

Without the RTI, the South Project would begin at Anaconda Substation with a 230 kV extension to Clayton Substation and then continue to Antelope Substation at 500 kV. As such, Options 12 and 13 combine to make up the preferred South Project. This route is made up of Segments S1+S2+S3+S4+S8, as shown in Figure *6.10 – Preferred South Route (Project)*.

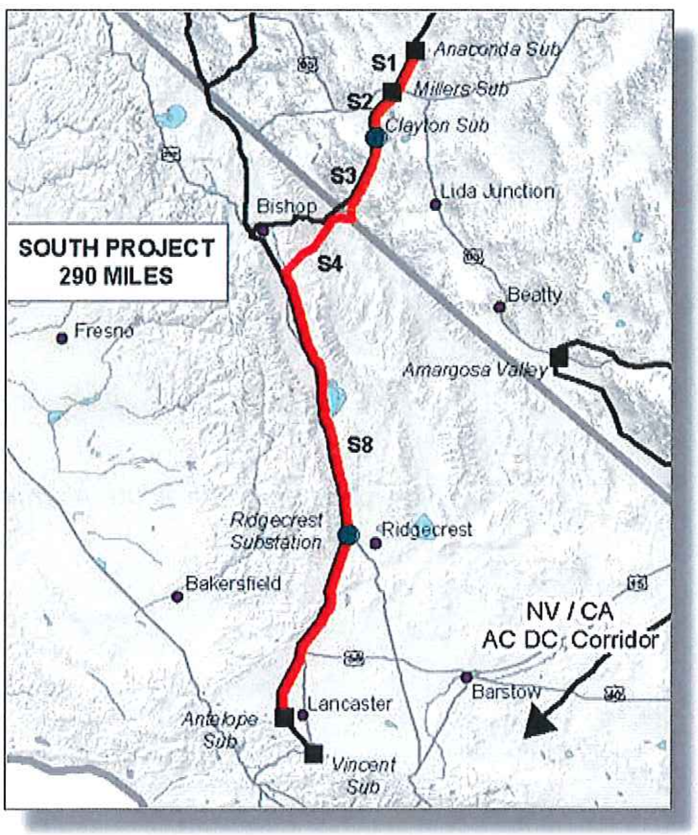


Figure 6.10 – Preferred South Route (Project)

If the RTI is built, the South Project would extend from either Clayton (Option 13) or Lida Substation (Option 17) to Antelope Substation at 500 kV. Note that, with the RTI in place, Options 18 and 19 are eliminated from consideration as Segment S5 would be unnecessary. From a transmission only point of view, Options 13 (Segments S3+S4+S8, from Clayton to Antelope) and 17 (Segments S6+S4+S8, from Lida to Antelope) are essentially the same cost; though Option 13 would be preferred from an evaluation matrix weighting standpoint. However, when the substation costs are added in, as discussed in Section 5, Option 17 is much less expensive and Lida Substation was chosen as the preferred starting point for this project alternative, as shown in *Figure 6.11 – South Route Alternative without RTI but with VEA Project*. Once this project moves forward and into the NEPA process, coordination with NV Energy would be critical in establishing the beginning terminus of the line, and Option 13 would remain in consideration as an alternative requiring further investigation.

For the South Alternate Project, Clayton Substation to Pahrump, also discussed in Section 5, Option 16 is the preferred route. This route is shown on *Figure 6.11* as well.

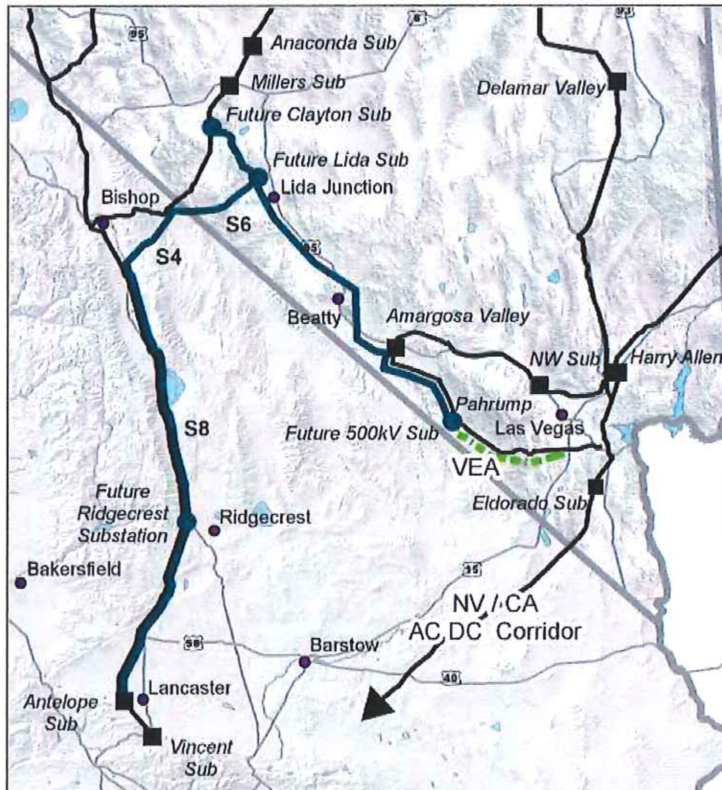


Figure 6.11 – South Route Alternative without RTI but with VEA Project

Option	Voltage	Route Segments	Line Terminals	Total Mileage	Total Transmission Cost[1]	Total Transmission Cost/Mile[1]	Weighted Score
North Project:							
3	345 kV	N1+N3+N5+N8	Oreana - Viewland	126	$172,880,000	$1,372,000	66.4
7	345 kV	N2+N3+N5+N8	Fernley - Viewland	101	$140,940,000	$1,395,000	68.7
East Project:							
9	345 kV	E1+E2 (345)	Robinson - IPP	167	$207,870,000	$1,245,000	84.1
10	500 kV	E1+E2 (500)	Robinson - IPP	167	$303,840,000	$1,819,000	78.1
South Project - Without RTI:							
12	230 kV	S1+S2	Anaconda - Clayton	37	$20,840,000	$563,000	99.0
13	500 kV	S3+S4+S8	Clayton - Antelope	253	$476,120,000	$1,882,000	52.1
South Project - Alternate:							
16	500 kV	S5+SE	Clayton - Pahrump	174	$299,790,000	$1,723,000	86.6
South Project - With RTI:							
17	500 kV	S4+S6+S8	Lida - Anelope	251	$476,230,000	$1,897,000	45.0

[1] *Costs are rounded*

Table 6.1 – Evaluation Matrix Preferred Routes Summary

Scoring Criteria	Scoring Methodology	Weight Max	North Project Option Scores - From Oreana							
			1		2		3		4	
			N1+N3+N4+N7		N1+N3+N4+N6+N8		N1+N3+N5+N8		N1+N3+N5+N6+N7	
			Raw	Weighted	Raw	Weighted	Raw	Weighted	Raw	Weighted
Permitting	Sum of the following five criteria scores:	50%	42.0	21.0	44.3	22.2	77.9	39.0	57.2	28.6
WA's and WSA's	Raw Score = Max Score * (1 - (Route Length within 1/2 mile of WA's or WSA's) / (Maximum Route Length within 1/2 mile of WA's or WSA's))	18	0.0	0.0	2.4	1.2	13.3	6.7	6.0	3.0
Fish & Game Critical Habitat	Raw Score = Max Score * (1 - (Route Area crossing Fish and Game Habitat) / (Maximum Route Area crossing Fish and Game Habitat))	18	12.4	6.2	12.7	6.3	14.7	7.3	9.8	4.9
Herd Management Areas	Raw Score = Max Score * (1 - (Route Area crossing Herd Management Areas) / (Maximum Route Area crossing Herd Management Areas))	18	2.3	1.2	2.6	1.3	8.1	4.1	0.6	0.3
Wetlands	Raw Score = Max Score * (1 - (Route Area crossing Wetlands) / (Maximum Route Area crossing Wetlands))	18	0.0	0.0	0.3	0.2	14.6	7.3	14.3	7.2
ACEC - Area of Critical Environmental Concern	Raw Score = Max Score * (1 - (Route Area crossing Areas of Critical Env. Concern) / (Maximum Route Area crossing Areas of Critical Env. Concern))	18	18.0	9.0	17.2	8.6	18.0	9.0	17.2	8.6
Additional CEQA Considerations	Raw Score = Max Score * (1 - (Route Length in California) / (Maximum Route Length in California))	10	9.3	4.6	9.1	4.6	9.1	4.6	9.3	4.6
R/W Acquisition	Sum of the following five criteria scores:	30%	90.0	27.0	70.4	21.1	41.9	12.6	58.9	17.7
Private Land	Raw Score = Max Score * (1 - (Route Area crossing Private Land) / (Maximum Route Area crossing Private Land))	35	26.6	8.0	22.2	6.7	23.5	7.1	25.5	7.6
State & Local Land	Raw Score = Max Score * (1 - (Route Area crossing State Land) / (Maximum Route Area crossing State Land))	15	15.0	4.5	14.9	4.5	14.9	4.5	15.0	4.5
Military Land	Raw Score = Max Score * (1 - (Route Area crossing Military Land) / (Maximum Route Area crossing Military Land))	15	15.0	4.5	0.0	0.0	0.0	0.0	15.0	4.5
BIA Land	Raw Score = Max Score * (1 - (Route Area crossing BIA Land) / (Maximum Route Area crossing BIA Land))	30	30.0	9.0	30.0	9.0	0.0	0.0	0.0	0.0
Crossings	Raw Score = Max Score * (1- (Route # of Crossings) / (Maximum Route # of Crossings))	5	3.4	1.0	3.3	1.0	3.5	1.0	3.4	1.0
Constructability	Sum of the following five criteria scores:	20%	53.9	10.8	51.7	10.3	74.4	14.9	69.6	13.9
Existing Access	Raw Score = Max Score * (1 - (Route Length @ Poor + 0.5 * Route Length @ Good) / (Max Route Length @ Poor + 0.5 * Route Length @ Good))	30	14.1	2.8	11.4	2.3	15.2	3.0	13.5	2.7
Slope	Raw Score = Max Score * (1 - (Route Area > 9% Slope) / (Maximum Route Area > 9% Slope))	25	17.3	3.5	16.2	3.2	19.2	3.8	17.7	3.5
Stream Crossings	Raw Score = Max Score * (1- (Route # of Stream Crossings) / Maximum # of Stream Crossings))	10	7.5	1.5	8.8	1.8	8.8	1.8	7.5	1.5
Vegetation	Raw Score = Max Score * (1 - (Route Area crossing Forest Vegetation) / (Maximum Route Area crossing Forest Vegetation))	15	15.0	3.0	15.0	3.0	15.0	3.0	15.0	3.0
Wetlands	Raw Score = Max Score * (1 - (Route Area crossing Wetlands) / (Maximum Route Area crossing Wetlands))	20	0.0	0.0	0.3	0.1	16.3	3.3	15.9	3.2
Total Score		300	186.0	58.8	166.5	53.6	194.2	66.4	185.7	60.2

Table 6.2 – Evaluation Matrix – North Project Options – From Oreana

Scoring Criteria	Scoring Methodology	Weight Max	North Project Option Scores - From Fernley							
			5		6		7		8	
			N2+N3+N4+N7		*N2+N3+N4+N6+N8*		*N2+N3+N5+N8*		*N2+N3+N5+N6+N7*	
			Raw	Weighted	Raw	Weighted	Raw	Weighted	Raw	Weighted
Permitting	Sum of the following five criteria scores:	50%	41.1	20.6	43.4	21.7	77.0	38.5	56.3	28.1
WA's and WSA's	Raw Score = Max Score * (1 - (Route Length within 1/2 mile of WA's or WSA's) / (Maximum Route Length within 1/2 mile of WA's or WSA's))	18	0.0	0.0	2.4	1.2	13.3	6.7	6.0	3.0
Fish & Game Critical Habitat	Raw Score = Max Score * (1 - (Route Area crossing Fish and Game Habitat) / (Maximum Route Area crossing Fish and Game Habitat))	18	11.3	5.6	11.5	5.8	13.5	6.8	8.6	4.3
Herd Management Areas	Raw Score = Max Score * (1 - (Route Area crossing Herd Management Areas) / (Maximum Route Area crossing Herd Management Areas))	18	1.8	0.9	2.0	1.0	7.6	3.8	0.0	0.0
Wetlands	Raw Score = Max Score * (1 - (Route Area crossing Wetlands) / (Maximum Route Area crossing Wetlands))	18	0.8	0.4	1.1	0.6	15.5	7.7	15.2	7.6
ACEC - Area of Critical Environmental Concern	Raw Score = Max Score * (1 - (Route Area crossing Areas of Critical Env. Concern) / (Maximum Route Area crossing Areas of Critical Env. Concern))	18	18.0	9.0	17.2	8.6	18.0	9.0	17.2	8.6
Additional CEQA Considerations	Raw Score = Max Score * (1 - (Route Length in California) / (Maximum Route Length in California))	10	9.3	4.6	9.1	4.6	9.1	4.6	9.3	4.6
R/W Acquisition	Sum of the following five criteria scores:	30%	94.2	28.3	74.6	22.4	46.0	13.8	63.0	18.9
Private Land	Raw Score = Max Score * (1 - (Route Area crossing Private Land) / (Maximum Route Area crossing Private Land))	35	30.4	9.1	26.0	7.8	27.3	8.2	29.2	8.8
State & Local Land	Raw Score = Max Score * (1 - (Route Area crossing State Land) / (Maximum Route Area crossing State Land))	15	15.0	4.5	14.9	4.5	14.9	4.5	15.0	4.5
Military Land	Raw Score = Max Score * (1 - (Route Area crossing Military Land) / (Maximum Route Area crossing Military Land))	15	15.0	4.5	0.0	0.0	0.0	0.0	15.0	4.5
BIA Land	Raw Score = Max Score * (1 - (Route Area crossing BIA Land) / (Maximum Route Area crossing BIA Land))	30	30.0	9.0	30.0	9.0	0.0	0.0	0.0	0.0
Crossings	Raw Score = Max Score * (1- (Route # of Crossings) / (Maximum Route # of Crossings))	5	3.8	1.1	3.8	1.1	3.9	1.2	3.8	1.1
Constructability	Sum of the following five criteria scores:	20%	61.4	12.3	59.2	11.8	81.9	16.4	77.1	15.4
Existing Access	Raw Score = Max Score * (1 - (Route Length @ Poor + 0.5 * Route Length @ Good) / (Max Route Length @ Poor + 0.5 * Route Length @ Good))	30	17.8	3.6	15.1	3.0	18.8	3.8	17.2	3.4
Slope	Raw Score = Max Score * (1 - (Route Area > 9% Slope) / (Maximum Route Area > 9% Slope))	25	19.0	3.8	17.9	3.6	20.9	4.2	19.3	3.9
Stream Crossings	Raw Score = Max Score * (1- (Route # of Stream Crossings) / Maximum # of Stream Crossings))	10	8.8	1.8	10.0	2.0	10.0	2.0	8.8	1.8
Vegetation	Raw Score = Max Score * (1 - (Route Area crossing Forest Vegetation) / (Maximum Route Area crossing Forest Vegetation))	15	15.0	3.0	15.0	3.0	15.0	3.0	15.0	3.0
Wetlands	Raw Score = Max Score * (1 - (Route Area crossing Wetlands) / (Maximum Route Area crossing Wetlands))	20	0.9	0.2	1.2	0.2	17.2	3.4	16.8	3.4
Total Score		300	196.7	61.1	177.2	55.9	204.9	68.7	196.4	62.5

Table 6.3 – Evaluation Matrix – North Project Options – From North Fernley

Scoring Criteria	Scoring Methodology	Weight Max	East Project Option Scores - From Robinson				IPP - Mona	
			9		10		11	
			E1+E2 (345)		*E1+E2 (500)*		*E3 (345)*	
			Raw	Weighted	Raw	Weighted	Raw	Weighted
Permitting	Sum of the following five criteria scores:	50%	86.4	43.2	79.9	40.0	99.2	49.6
WA's and WSA's	Raw Score = Max Score * (1 - (Route Length within 1/2 mile of WA's or WSA's) / (Maximum Route Length within 1/2 mile of WA's or WSA's))	18	15.9	8.0	15.9	8.0	18.0	9.0
Fish & Game Critical Habitat	Raw Score = Max Score * (1 - (Route Area crossing Fish and Game Habitat) / (Maximum Route Area crossing Fish and Game Habitat))	18	6.5	3.2	0.0	0.0	17.2	8.6
Herd Management Areas	Raw Score = Max Score * (1 - (Route Area crossing Herd Management Areas) / (Maximum Route Area crossing Herd Management Areas))	18	18.0	9.0	18.0	9.0	18.0	9.0
Wetlands	Raw Score = Max Score * (1 - (Route Area crossing Wetlands) / (Maximum Route Area crossing Wetlands))	18	18.0	9.0	18.0	9.0	18.0	9.0
ACEC - Area of Critical Environmental Concern	Raw Score = Max Score * (1 - (Route Area crossing Areas of Critical Env. Concern) / (Maximum Route Area crossing Areas of Critical Env. Concern))	18	18.0	9.0	18.0	9.0	18.0	9.0
Additional CEQA Considerations	Raw Score = Max Score * (1 - (Route Length in California) / (Maximum Route Length in California))	10	10.0	5.0	10.0	5.0	10.0	5.0
R/W Acquisition	Sum of the following five criteria scores:	30%	93.2	28.0	90.6	27.2	88.9	26.7
Private Land	Raw Score = Max Score * (1 - (Route Area crossing Private Land) / (Maximum Route Area crossing Private Land))	35	32.1	9.6	30.4	9.1	26.4	7.9
State & Local Land	Raw Score = Max Score * (1 - (Route Area crossing State Land) / (Maximum Route Area crossing State Land))	15	13.2	4.0	12.2	3.7	13.6	4.1
Military Land	Raw Score = Max Score * (1 - (Route Area crossing Military Land) / (Maximum Route Area crossing Military Land))	15	15.0	4.5	15.0	4.5	15.0	4.5
BIA Land	Raw Score = Max Score * (1 - (Route Area crossing BIA Land) / (Maximum Route Area crossing BIA Land))	30	30.0	9.0	30.0	9.0	30.0	9.0
Crossings	Raw Score = Max Score * (1- (Route # of Crossings) / (Maximum Route # of Crossings))	5	3.0	0.9	3.0	0.9	4.0	1.2
Constructability	Sum of the following five criteria scores:	20%	64.5	12.9	54.6	10.9	86.6	17.3
Existing Access	Raw Score = Max Score * (1 - (Route Length @ Poor + 0.5 * Route Length @ Good) / (Max Route Length @ Poor + 0.5 * Route Length @ Good))	30	16.7	3.3	16.7	3.3	25.3	5.1
Slope	Raw Score = Max Score * (1 - (Route Area > 9% Slope) / (Maximum Route Area > 9% Slope))	25	17.0	3.4	12.5	2.5	22.5	4.5
Stream Crossings	Raw Score = Max Score * (1- (Route # of Stream Crossings) / Maximum # of Stream Crossings))	10	5.4	1.1	5.4	1.1	8.8	1.8
Vegetation	Raw Score = Max Score * (1 - (Route Area crossing Forest Vegetation) / (Maximum Route Area crossing Forest Vegetation))	15	5.4	1.1	0.0	0.0	10.1	2.0
Wetlands	Raw Score = Max Score * (1 - (Route Area crossing Wetlands) / (Maximum Route Area crossing Wetlands))	20	20.0	4.0	20.0	4.0	20.0	4.0
Total Score		300	244.2	84.1	225.2	78.1	274.8	93.6

Table 6.4 – Evaluation Matrix – East Project Options

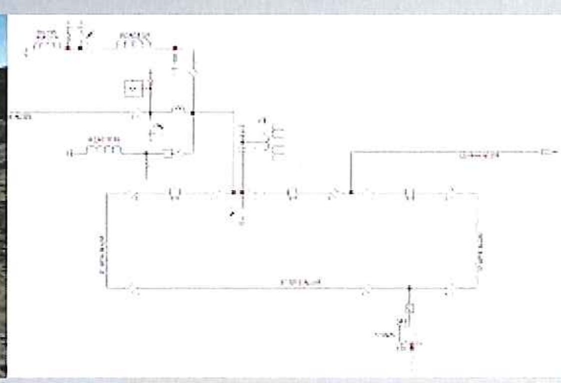
Scoring Criteria	Scoring Methodology	Weight Max	Anaconda - Clayton		South Project Option Scores - From Clayton					
			12		13		14		15	
			S1+S2		S3+S4+S8		S4+S5+S6+S8		S7+S8	
			Raw	Weighted	Raw	Weighted	Raw	Weighted	Raw	Weighted
Permitting	Sum of the following five criteria scores:	50%	99.9	49.9	59.8	29.9	50.2	25.1	52.3	26.1
WA's and WSA's	Raw Score = Max Score * (1 - (Route Length within 1/2 mile of WA's or WSA's) / (Maximum Route Length within 1/2 mile of WA's or WSA's))	18	18.0	9.0	14.8	7.4	14.8	7.4	16.7	8.4
Fish & Game Critical Habitat	Raw Score = Max Score * (1 - (Route Area crossing Fish and Game Habitat) / (Maximum Route Area crossing Fish and Game Habitat))	18	18.0	9.0	17.4	8.7	13.6	6.8	9.5	4.8
Herd Management Areas	Raw Score = Max Score * (1 - (Route Area crossing Herd Management Areas) / (Maximum Route Area crossing Herd Management Areas))	18	17.9	8.9	12.8	6.4	7.1	3.5	13.6	6.8
Wetlands	Raw Score = Max Score * (1 - (Route Area crossing Wetlands) / (Maximum Route Area crossing Wetlands))	18	18.0	9.0	13.0	6.5	13.0	6.5	12.4	6.2
ACEC - Area of Critical Environmental Concern	Raw Score = Max Score * (1 - (Route Area crossing Areas of Critical Env. Concern) / (Maximum Route Area crossing Areas of Critical Env. Concern))	18	18.0	9.0	0.7	0.4	0.7	0.4	0.0	0.0
Additional CEQA Considerations	Raw Score = Max Score * (1 - (Route Length in California) / (Maximum Route Length in California))	10	10.0	5.0	1.1	0.5	1.1	0.5	0.0	0.0
R/W Acquisition	Sum of the following five criteria scores:	30%	99.4	29.8	47.5	14.2	39.0	11.7	44.0	13.2
Private Land	Raw Score = Max Score * (1 - (Route Area crossing Private Land) / (Maximum Route Area crossing Private Land))	35	34.7	10.4	0.0	0.0	0.5	0.1	1.0	0.3
State & Local Land	Raw Score = Max Score * (1 - (Route Area crossing State Land) / (Maximum Route Area crossing State Land))	15	15.0	4.5	4.3	1.3	4.3	1.3	0.0	0.0
Military Land	Raw Score = Max Score * (1 - (Route Area crossing Military Land) / (Maximum Route Area crossing Military Land))	15	15.0	4.5	12.9	3.9	12.9	3.9	12.9	3.9
BIA Land	Raw Score = Max Score * (1 - (Route Area crossing BIA Land) / (Maximum Route Area crossing BIA Land))	30	30.0	9.0	30.0	9.0	20.5	6.2	30.0	9.0
Crossings	Raw Score = Max Score * (1- (Route # of Crossings) / (Maximum Route # of Crossings))	5	4.7	1.4	0.3	0.1	0.8	0.3	0.1	0.0
Constructability	Sum of the following five criteria scores:	20%	96.2	19.2	40.0	8.0	27.7	5.5	27.4	5.5
Existing Access	Raw Score = Max Score * (1 - (Route Length @ Poor + 0.5 * Route Length @ Good) / (Max Route Length @ Poor + 0.5 * Route Length @ Good))	30	27.2	5.4	7.3	1.5	4.8	1.0	2.7	0.5
Slope	Raw Score = Max Score * (1 - (Route Area > 9% Slope) / (Maximum Route Area > 9% Slope))	25	24.0	4.8	4.4	0.9	3.5	0.7	2.0	0.4
Stream Crossings	Raw Score = Max Score * (1- (Route # of Stream Crossings) / Maximum # of Stream Crossings))	10	10.0	2.0	2.1	0.4	2.1	0.4	0.0	0.0
Vegetation	Raw Score = Max Score * (1 - (Route Area crossing Forest Vegetation) / (Maximum Route Area crossing Forest Vegetation))	15	15.0	3.0	11.8	2.4	2.9	0.6	8.9	1.8
Wetlands	Raw Score = Max Score * (1 - (Route Area crossing Wetlands) / (Maximum Route Area crossing Wetlands))	20	20.0	4.0	14.4	2.9	14.4	2.9	13.8	2.8
Total Score		300	295.5	99.0	147.3	52.1	116.9	42.3	123.6	44.8

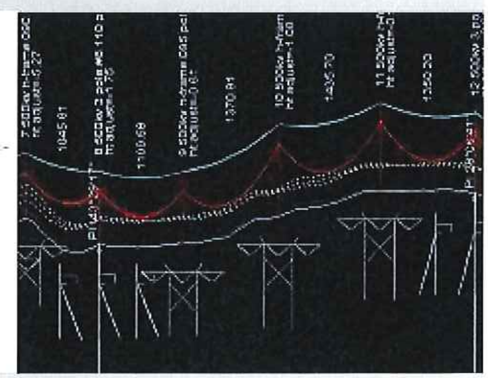
Table 6.5 – Evaluation Matrix – South Project Options – From Clayton

Scoring Criteria	Scoring Methodology	Weight Max	Alternate		South Project Option Scores - From Lida					
			16		17		18		19	
			S5+SE		*S4+S6+S8*		*S3+S4+S5+S8*		*S5+S7+S8*	
			Raw	Weighted	Raw	Weighted	Raw	Weighted	Raw	Weighted
Permitting	Sum of the following five criteria scores:	50%	96.5	48.3	53.7	26.8	56.3	28.2	48.8	24.4
WA's and WSA's	Raw Score = Max Score * (1 - (Route Length within 1/2 mile of WA's or WSA's) / (Maximum Route Length within 1/2 mile of WA's or WSA's))	18	18.0	9.0	14.8	7.4	14.8	7.4	16.7	8.4
Fish & Game Critical Habitat	Raw Score = Max Score * (1 - (Route Area crossing Fish and Game Habitat) / (Maximum Route Area crossing Fish and Game Habitat))	18	18.0	9.0	13.6	6.8	17.4	8.7	9.5	4.8
Herd Management Areas	Raw Score = Max Score * (1 - (Route Area crossing Herd Management Areas) / (Maximum Route Area crossing Herd Management Areas))	18	14.5	7.3	10.5	5.3	9.4	4.7	10.1	5.0
Wetlands	Raw Score = Max Score * (1 - (Route Area crossing Wetlands) / (Maximum Route Area crossing Wetlands))	18	18.0	9.0	13.0	6.5	13.0	6.5	12.4	6.2
ACEC - Area of Critical Environmental Concern	Raw Score = Max Score * (1 - (Route Area crossing Areas of Critical Env. Concern) / (Maximum Route Area crossing Areas of Critical Env. Concern))	18	18.0	9.0	0.7	0.4	0.7	0.4	0.0	0.0
Additional CEQA Considerations	Raw Score = Max Score * (1 - (Route Length in California) / (Maximum Route Length in California))	10	10.0	5.0	1.1	0.5	1.1	0.5	0.0	0.0
R/W Acquisition	Sum of the following five criteria scores:	30%	86.9	26.1	39.1	11.7	47.4	14.2	43.9	13.2
Private Land	Raw Score = Max Score * (1 - (Route Area crossing Private Land) / (Maximum Route Area crossing Private Land))	35	29.8	8.9	0.5	0.1	0.0	0.0	1.0	0.3
State & Local Land	Raw Score = Max Score * (1 - (Route Area crossing State Land) / (Maximum Route Area crossing State Land))	15	15.0	4.5	4.3	1.3	4.3	1.3	0.0	0.0
Military Land	Raw Score = Max Score * (1 - (Route Area crossing Military Land) / (Maximum Route Area crossing Military Land))	15	15.0	4.5	12.9	3.9	12.9	3.9	12.9	3.9
BIA Land	Raw Score = Max Score * (1 - (Route Area crossing BIA Land) / (Maximum Route Area crossing BIA Land))	30	24.8	7.4	20.5	6.2	30.0	9.0	30.0	9.0
Crossings	Raw Score = Max Score * (1- (Route # of Crossings) / (Maximum Route # of Crossings))	5	2.4	0.7	0.9	0.3	0.2	0.1	0.0	0.0
Constructability	Sum of the following five criteria scores:	20%	61.2	12.2	32.4	6.5	35.3	7.1	22.7	4.5
Existing Access	Raw Score = Max Score * (1 - (Route Length @ Poor + 0.5 * Route Length @ Good) / (Max Route Length @ Poor + 0.5 * Route Length @ Good))	30	11.4	2.3	7.5	1.5	4.6	0.9	0.0	0.0
Slope	Raw Score = Max Score * (1 - (Route Area > 9% Slope) / (Maximum Route Area > 9% Slope))	25	9.4	1.9	5.5	1.1	2.5	0.5	0.0	0.0
Stream Crossings	Raw Score = Max Score * (1- (Route # of Stream Crossings) / Maximum # of Stream Crossings))	10	5.4	1.1	2.1	0.4	2.1	0.4	0.0	0.0
Vegetation	Raw Score = Max Score * (1 - (Route Area crossing Forest Vegetation) / (Maximum Route Area crossing Forest Vegetation))	15	15.0	3.0	2.9	0.6	11.8	2.4	8.9	1.8
Wetlands	Raw Score = Max Score * (1 - (Route Area crossing Wetlands) / (Maximum Route Area crossing Wetlands))	20	20.0	4.0	14.4	2.9	14.4	2.9	13.8	2.8
Total Score		300	244.6	86.6	125.1	45.0	139.1	49.5	115.4	42.1

Table 6.6 – Evaluation Matrix – South Project Options – From Lida

Section 7: Conceptual Design & Costing





SECTION 7: CONCEPTUAL DESIGN AND COSTING

7.1 SECTION PURPOSE

This section presents the process used to complete the conceptual design and costing used to evaluate the multiple of alternatives that were considered to reach final selection of the preferred project alternatives. In order to calculate and compare the economics of the various route options, estimates were completed for each of the line segments individually and then combined to form a route option estimate. Rather than default to a common cost per mile assumption for the different voltages, the estimates were built from the bottom up, starting with a conceptual design and incorporating the appropriate unit costs. The major advantage of completing the estimates in this manner is that they take the constraints identified through the mapping effort into account, yielding estimates that more closely reflect the actual field conditions. A second advantage is that as the project becomes more refined, the cost estimate can be easily updated to reflect the latest information available. Conceptual design and costing was also completed for each of the substation projects that would be required for the various alternatives in order to reach a final cost evaluation.

7.2 TRANSMISSION LINE CONCEPTUAL DESIGN

The transmission line cost estimates used in this study are based on a conceptual design. The conceptual design was completed in PLS-CADD and the results were exported to an Excel spreadsheet to complete the estimating process. Completion of the conceptual design followed the following steps:

1. Alignment: As discussed in Section 6, multiple route options and alignment segments were considered. Once the segments were established, they were imported into the model to begin the conceptual design process.
2. Terrain: For this conceptual level of design, a digital terrain model was imported from the National Elevation Dataset. This data is based on a grid spaced at 10 meters and is therefore not accurate enough for a detailed final design. It is, however, adequate for use in conceptual designs for study purposes. An example model with the USGS topographic map "draped" over the terrain and the alignment shown in blue is depicted in *Figure 7.1 – Example Terrain Model.*

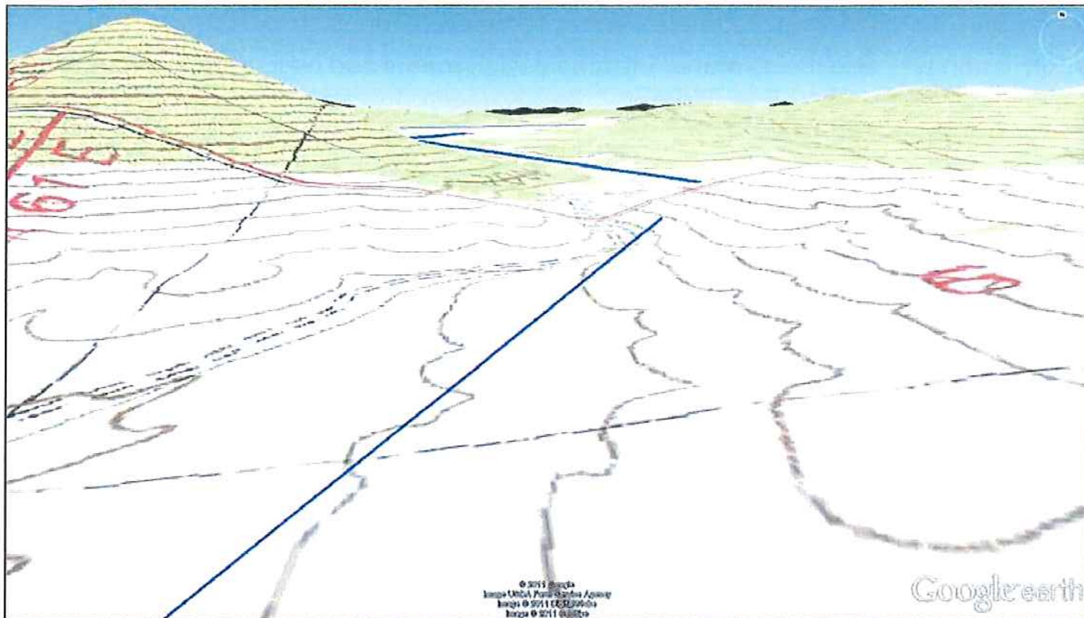


Figure 7.1 – Example Terrain Model

3. Design Criteria: NESC code requirements were used to establish the design criteria for the conceptual design. Because many of the line segments are in California, G.O. 95 code requirements were also considered and used where more conservative. Due to the granular nature of the terrain information, a buffer was added to the required clearances to ensure that adequate clearance would be maintained.

4. Conductor: The conductor sizes and configuration were then established as discussed in Section 5.5, Preliminary Technical Parameters, and incorporated into the design model and estimating spreadsheet.

5. Structure Family: At the voltages being considered, steel structures were chosen (i.e. wood, concrete, etc. were not considered as viable). Both lattice (guyed and self-supporting) and tubular steel (guyed and self-supporting) configurations were considered, and it was decided that H-Frame structures would be used for the majority of the route segments and mono pole structures would be used in areas of physical constraints. The decision on a structure family to be used in a line design is typically based on an established line route and requires an extensive study. Such an effort is beyond the scope of this study, so the decision to assume H-Frame structures was based largely on their simplicity to model and estimate. The family of structures used in the conceptual design is shown in Figure *7.2 – Typical 500 kV Structure Types used for Conceptual Design,* which is included to provide an idea of the conceptual design level completed. Typical wind and weight span capacities were established using NESC load conditions as the

basis, and installed cost estimates were completed for each of the structures. This information was also incorporated into the design model and estimating spreadsheet.

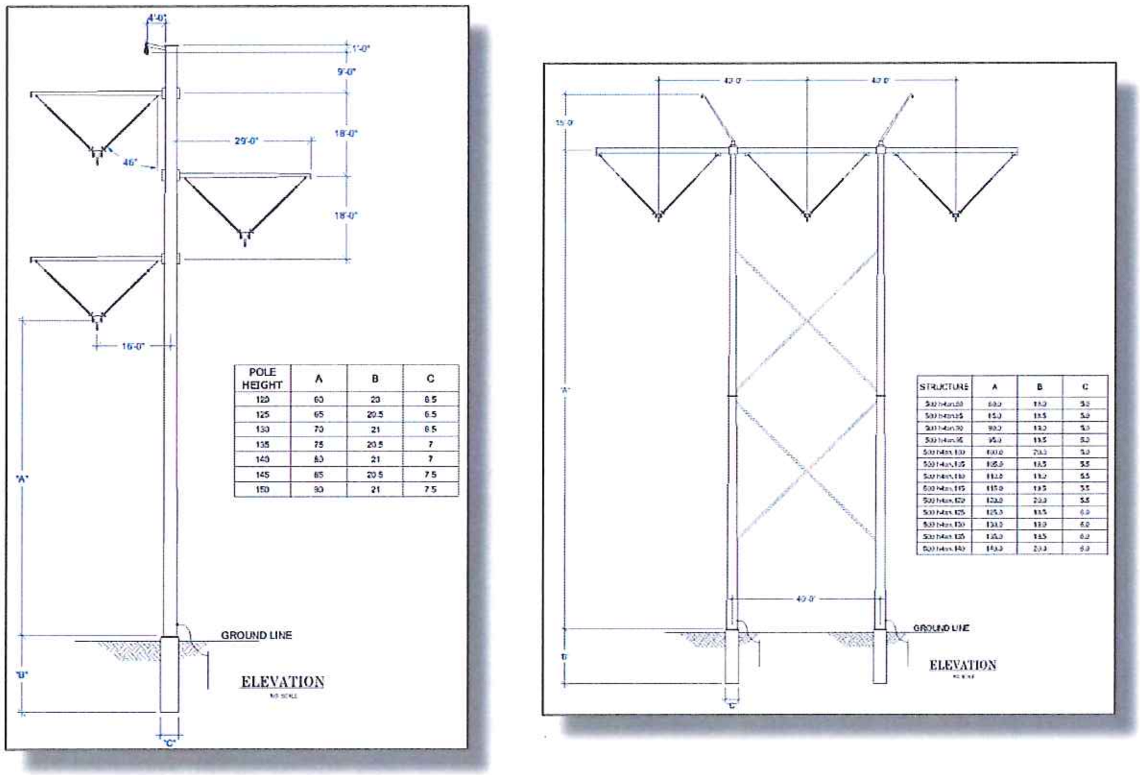


Figure 7.2 – Typical 500 kV Structure Types used for Conceptual Design

6. Structure Spotting: The final step in creating a conceptual design is to spot structures along the alignment. PLS-CADD has a structure spotting routine built into it that incorporates the terrain, design criteria, structure capacities, and costs into a proposed design. Some minor adjustments were made to the PLS-CADD output, but the design remains largely unchanged. Examples of the conceptual design are shown in *Figures 7.3 – Structure Spotting Example*, and *7.4 - Typical Modeling Screen of PLS-CADD Conceptual Design*.

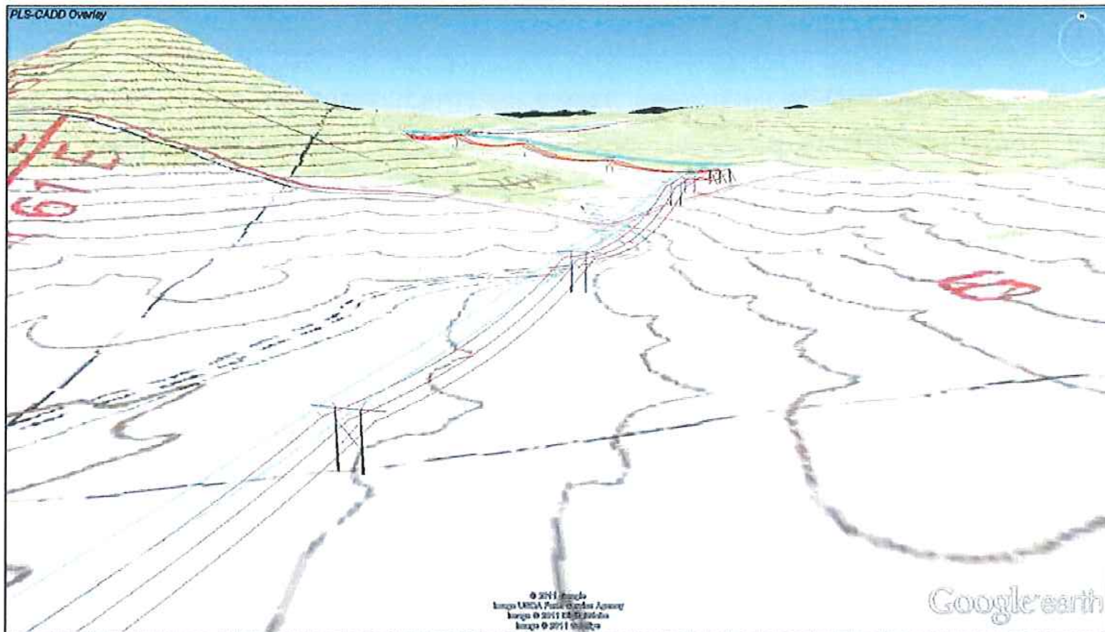


Figure 7.3 – Structure Spotting Example

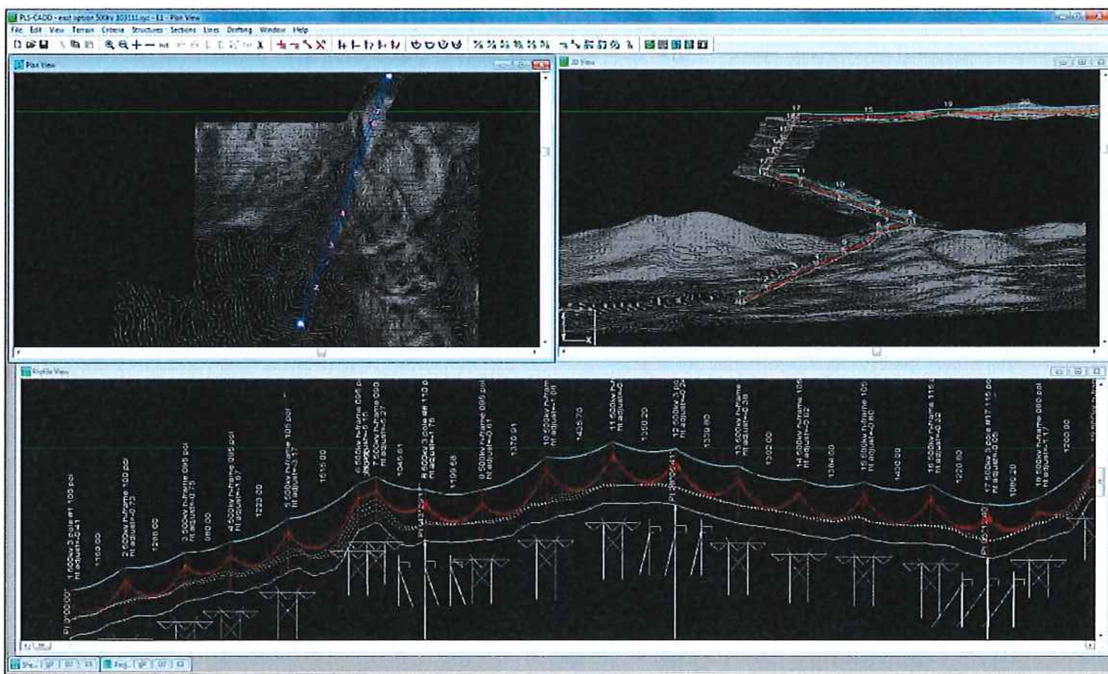


Figure 7.4 – Typical Modeling Screen of PLS-CADD Conceptual Design

7.3 TRANSMISSION LINE COSTING

Results from the conceptual design process yielded the structure and wire quantities and were exported from PLS-CADD to an Excel spreadsheet for final estimating purposes. These quantities were multiplied by material and labor unit costs giving the installed cost for the physical facilities. This comprises the majority of the cost to build the line, but the following "other" costs are necessary to be included to complete the overall project estimates.

- Project Management: Project Management fees for a team engaged in managing the project cost and schedule from development through in-service. These fees also include a consultant engaged in managing public and government relationships.
- Permitting: Permitting costs for consulting and agency fees associated with completing the NEPA process and other federal permits as required; completing the CEQA process (California only) and other jurisdictional permits as required including local, state, and UEPA permits; dealing with constraint impacts during the permitting process; obtaining crossing permits (Highway, Rail-Road, Utilities, etc.); and monitoring the construction process for compliance with the permit conditions.
- Right of Way Acquisition: Right of Way Acquisition costs for document research, surveying, mapping, and coordination fees associated with private rights-of-way acquisition; consultant, appraisal, and legal fees associated with negotiating easements on private lands; and fees paid to private land owners for easements across their property. For the purposes of this study, BIA lands were treated as private property.
- Engineering and Construction Management: Engineering fees to finalize the routing and conceptual design such that permit applications can be completed; surveying and mapping fees associated with completing the final design and supporting the permitting process; engineering fees associated with supporting the permitting and right-of-way acquisition processes; engineering fees associated with completing the detailed design and producing bid/construction packages; engineering fees associated with supporting the bid, award, and construction processes; surveying fees associated with staking structures, anchors, and offsets for construction; and construction manager fees associated with bidding/awarding the project, managing the construction cost and schedule, and maintaining the quality assurance program.
- Construction: Construction contractors' fees for project management and quality control; for ordering and managing all materials used to construct the project; for bonding and insurance as required by the construction contract; for building permits normally obtained by the construction contractor (e.g. Dust Control); for the cost to mobilize and demobilize the construction crews and equipment to the project base location; for the cost to build

access roads to the structure locations; for the cost to clear the right-of-way and/or trim/remove trees from the right-of-way; for the construction cost associated with establishing and maintaining BMP and other measures necessary to comply with the permit to construct; and for the construction cost associated with mitigating environmental conditions and restoring the right-of-way in accordance with the permit to construct.

Each of these items were assigned the appropriate unit (e.g. each, per acre, per mile, etc.), based on the GIS data and a unit cost for estimating. The data was incorporated into the Excel spreadsheet and the results were totaled along with the structure and wire costs to produce an overall segment cost. The segment costs were then combined to produce an overall cost estimate for each of the route options. Because of the preliminary nature of the data used in producing these estimates, a contingency factor was also added. Estimating results for the Preferred Route options are summarized in *Table 7.1 – Preferred Routes – Transmission Costs Summary*.

Table 7.1 – Preferred Routes – Transmission Costs Summary

ITEM	3 N1+N3+N5+N8 Orena - Viewland	7 N2+N3+N5+N8 Fernley - Viewland	9 E1+E2 (345) Robinson - IPP	10 E1+E2 (500) Robinson - IPP	12 S1+S2 Anaconda - Clayton	13 S3+S4+S8 Clayton - Antelope	16 S5+SE Clayton - Pahrump	17 S4+S6+S8 Lida - Antelope
Project Management								
Direct Estimate	$752,820	$600,300	$998,700	$998,700	$222,180	$1,513,920	$1,042,320	$1,500,540
Contingency Factor: Base = 5.0%	*6.7%*	*6.6%*	*5.8%*	*6.1%*	*5.0%*	*7.4%*	*5.7%*	*7.7%*
Contingency	$53,142	$41,688	$57,882	$60,887	$14,587	$104,100	$82,165	$116,448
Total Project Management	$805,962	$641,988	$1,056,582	$1,059,587	$236,767	$1,618,020	$1,124,485	$1,616,988
Engineering and Const Mgt								
Direct Estimate	$1,668,751	$1,330,665	$2,213,785	$2,380,235	$473,984	$3,608,176	$2,484,196	$3,576,287
Contingency Factor: Base = 10.0%	*13.4%*	*13.1%*	*11.6%*	*12.2%*	*10.1%*	*14.8%*	*11.3%*	*15.5%*
Contingency	$222,947	$174,730	$256,610	$290,228	$47,871	$533,494	$281,805	$554,204
Total Engineering and Const Mgt	$1,891,698	$1,505,395	$2,470,395	$2,670,463	$521,855	$4,141,670	$2,766,001	$4,130,491
Permitting								
Direct Estimate	$3,500,942	$2,909,852	$4,329,671	$6,508,520	$707,250	$12,315,133	$6,425,148	$12,341,996
Contingency Factor: Base = 15.0%	*24.2%*	*24.2%*	*23.5%*	*24.0%*	*22.5%*	*25.5%*	*22.8%*	*26.0%*
Contingency	$845,726	$704,913	$1,018,307	$1,562,412	$159,186	$3,142,092	$1,462,453	$3,205,700
Total Permitting	$4,346,667	$3,614,764	$5,347,979	$8,070,932	$866,437	$15,457,226	$7,887,601	$15,547,696
Right of Way								
Direct Estimate	$14,851,118	$11,788,259	$2,461,543	$3,804,825	$256,150	$28,682,478	$5,314,094	$30,005,165
Contingency Factor: Base = 15.0%	*28.1%*	*27.9%*	*25.8%*	*25.9%*	*25.5%*	*27.9%*	*26.1%*	*28.2%*
Contingency	$4,175,432	$3,292,259	$635,174	$986,332	$65,392	$7,992,167	$1,386,473	$8,473,927
Total Right of Way	$19,026,550	$15,080,519	$3,096,717	$4,791,157	$321,542	$36,674,645	$6,700,567	$38,479,092
Construction								
Direct Estimate - Structures	$71,558,100	$59,004,700	$95,961,100	$143,859,100	$7,007,100	$208,724,900	$139,977,400	$207,212,800
Direct Estimate - Wire	$37,831,432	$30,559,761	$50,849,644	$72,527,520	$6,737,239	$106,089,111	$72,782,541	$105,098,377
Direct Estimate - Other	$5,516,322	$4,599,948	$6,160,134	$7,393,327	$1,119,863	$9,893,144	$6,730,232	$10,449,434
Total Direct Estimate	$114,905,854	$94,164,409	$152,970,879	$223,779,947	$14,864,202	$324,707,155	$219,490,173	$322,760,611
Contingency Factor: Base = 15.0%	*27.8%*	*27.5%*	*28.1%*	*28.4%*	*27.1%*	*28.8%*	*28.2%*	*29.0%*
Contingency	$31,906,790	$25,935,915	$42,929,782	$63,466,276	$4,030,156	$93,516,322	$61,817,215	$93,695,734
Total Construction	$146,812,643	$120,100,324	$195,900,660	$287,246,222	$18,894,357	$418,223,477	$281,307,388	$416,456,345
Total Direct Estimate	$135,679,485	$110,793,485	$162,974,578	$237,472,227	$16,523,766	$370,826,862	$234,755,931	$370,184,599
Total Contingency Estimate	$37,204,035	$30,149,505	$44,897,755	$66,366,134	$4,317,192	$105,288,176	$65,030,112	$106,046,013
Total Project Estimate	$172,883,520	$140,942,990	$207,872,333	$303,838,361	$20,840,958	$476,115,038	$299,786,043	$476,230,612
Total Project Estimate (Rounded $10,000)	$172,880,000	$140,940,000	$207,870,000	$303,840,000	$20,840,000	$476,120,000	$299,790,000	$476,230,000
Coningency % of Total	*21.5%*	*21.4%*	*21.6%*	*21.8%*	*20.7%*	*22.1%*	*21.7%*	*22.3%*
Line Miles	126	101	167	167	38	253	174	251
Total Per Mile Costs	*$1,372,091*	*$1,395,475*	*$1,244,745*	*$1,819,391*	*$548,446*	*$1,881,878*	*$1,722,908*	*$1,897,333*
Total Per Mile Costs (Rounded $1,000)	*$1,372,000*	*$1,395,000*	*$1,245,000*	*$1,819,000*	*$548,000*	*$1,882,000*	*$1,723,000*	*$1,897,000*

7.4 SUBSTATION CONCEPTUAL LAYOUTS & COSTING

During the course of this transmission routing effort, a conceptual review of both existing and proposed substations was also completed. Conceptual layout of the proposed substation additions was completed in the form of one-line diagrams to allow for preliminary routing, costing and evaluation. These one-lines were completed with consideration of avoiding "and" pricing for wheeling charges. A thorough evaluation of each substation interconnection will be required in the final design effort and will involve each substation owner, as well as grid operator. This effort will likely either be completed concurrently with the WECC path rating process, or immediately on the heels of that effort. This effort is discussed in Section 9 of this report.

Note that the purpose of preparing the one-line diagrams was to support the development of preliminary cost estimates for the substation facilities associated with the proposed projects. The following substations are included as components of the proposed projects. Cost estimates for these substations are summarized in *Table 7.2 – Substation Cost Estimates Summary*.

7.4.1 North Project Substations

7.4.1.1 North Fernley Substation

North Fernley is a new 345 kV substation in the area north of Fernley, Nevada where the Pacific DC Intertie and the Valmy-Tracy 345 kV lines cross. The project requires folding one or both of the Valmy-Tracy 345 kV lines into the new substation. The North Project has two alternatives; the North Fernley Substation is included in Alternative 1. The one-line diagram and associated cost estimate assumes only one of the Valmy-Tracy 345 kV lines is folded into and out of the substation. The facilities at North Fernley Substation are estimated at approximately $16.0 million.

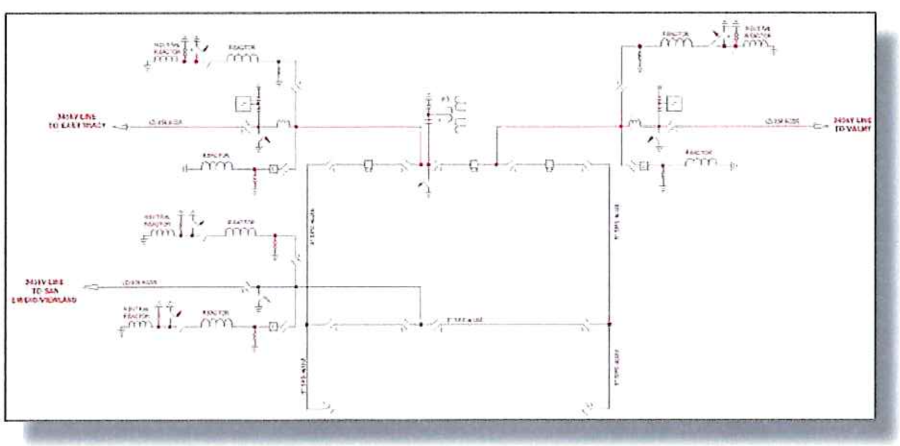


Figure 7.5 – Conceptual Layout of North Fernley Substation

7.4.1.2 Oreana Substation

Oreana Substation is a proposed 345 kV substation approximately 15 miles northeast of Lovelock, Nevada. NV Energy's RTI includes the initial construction of the Oreana 345 kV Substation. The North Project has two alternatives; the Oreana Substation is included in Alternative 2. North Project facility additions at Oreana Substation are estimated at approximately $8.9 million.

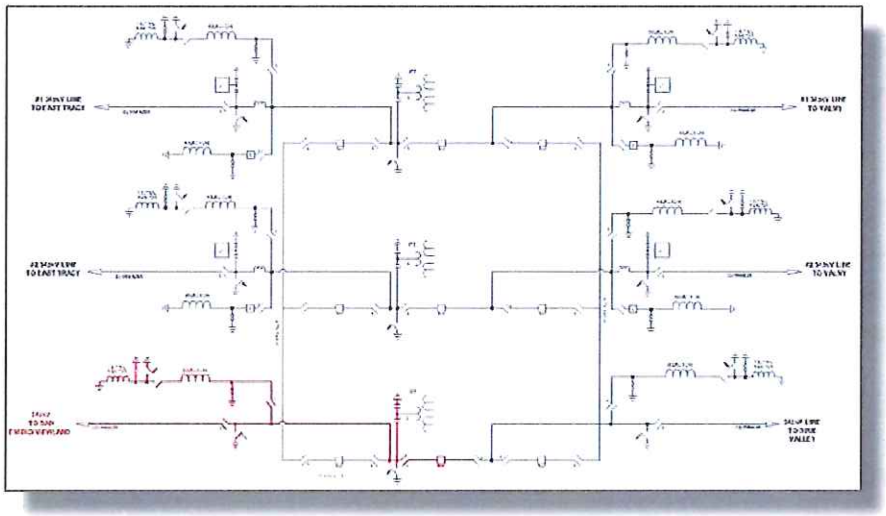


Figure 7.6 – Conceptual Layout of Oreana Substation

7.4.1.3 San Emidio Substation

San Emidio Substation is a future collector substation for renewable generation approximately 21 miles south of Gerlach, Nevada. This report assumes all improvements at San Emidio Substation would be funded by the renewable generation developers necessitating the facility. As a result, the $64.0 million estimate for San Emidio Substation is not added into the total estimate for the North Project.

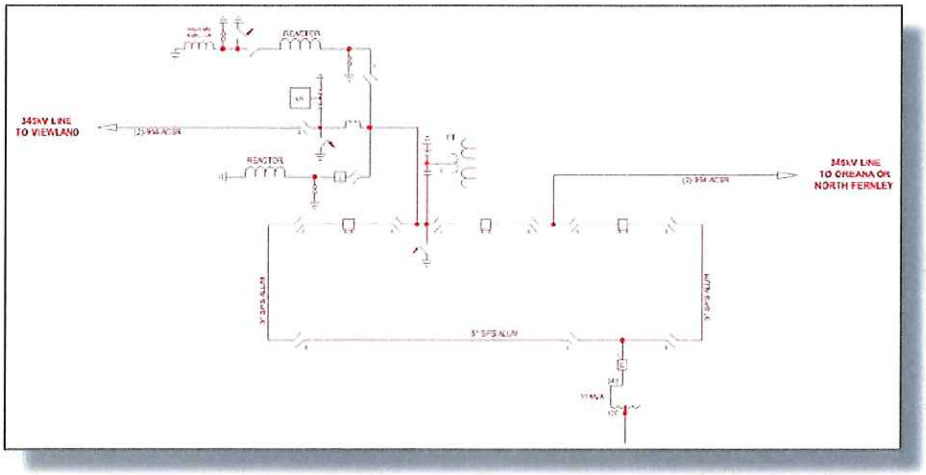


Figure 7.7 – Conceptual Layout of San Emidio Substation

7.4.1.4 Viewland Substation

Viewland Substation is a proposed 345 kV substation approximately 40 miles northeast of Susanville, California, on the Alturas Intertie.

Two cost estimates and associated one-line diagrams are included for Viewland Substation. The first cost estimate assumes the Viewland-Olinda project has not been built, so Viewland substation must be built from a Greenfield site; the associated cost estimate is $16.1 million.

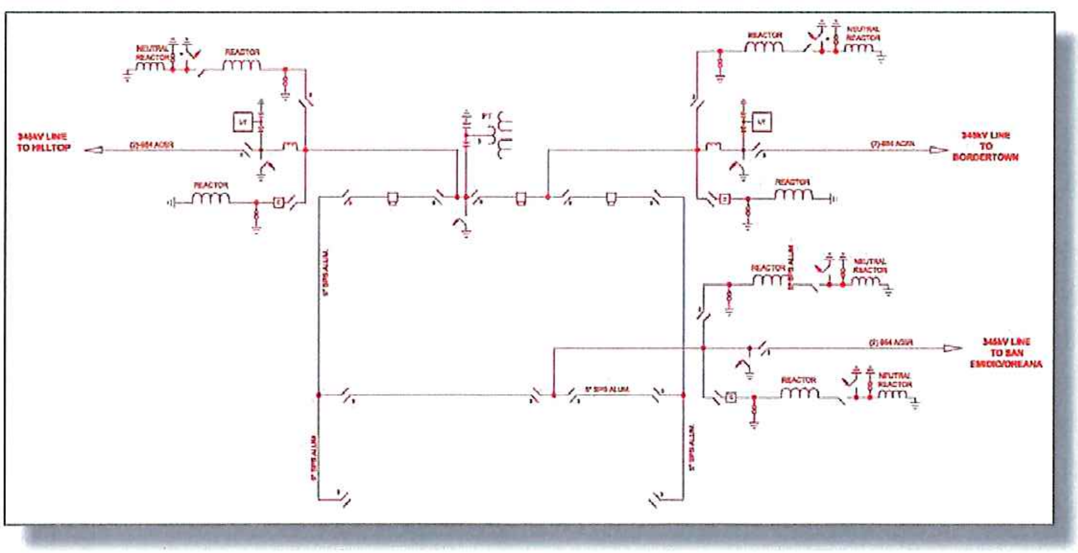


Figure 7.8 – Conceptual Layout of Viewland Substation - without LMUD Project

The second cost estimate for the North Project assumes the Viewland Substation has been developed with the Viewland-Olinda project; the Viewland Substation improvements associated with the North Project are estimated at $12.9 million.

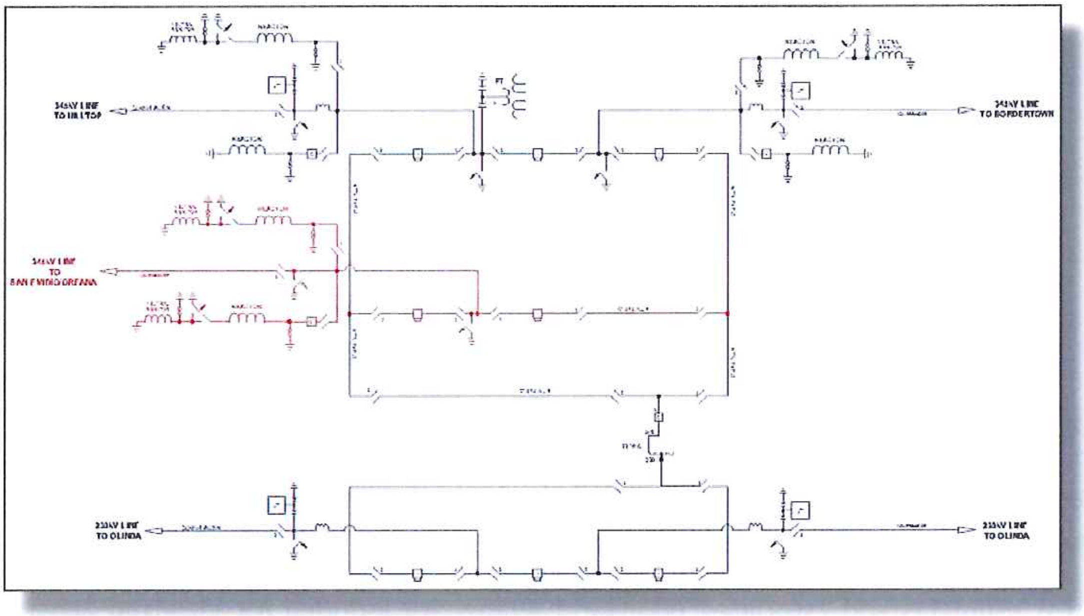


Figure 7.9 – Conceptual Layout of Viewland Substation - with LMUD Project

The North Project will also require the relocation of the Bordertown phase shifting transformer to Hilltop Substation. This relocation is estimated at approximately $3.2 million.

7.4.2 East Project Substations

7.4.2.1 Robinson Summit Substation

Robinson Summit Substation is a 500/345 kV substation presently under construction as part of the ON Line project. It is located approximately 17 miles northwest of Ely, Nevada. Information detailing the electrical equipment configuration at Robinson Summit Substation following completion of the ON Line Project was unavailable. The one-line diagram for Robinson Summit Substation depicts worst case assumptions with regard to the equipment required for the East Project. The Robinson Summit Substation improvements associated with the East Project are estimated at approximately $13.0 million for a 345 kV project and approximately $ 17.9 million for a 500 kV project.

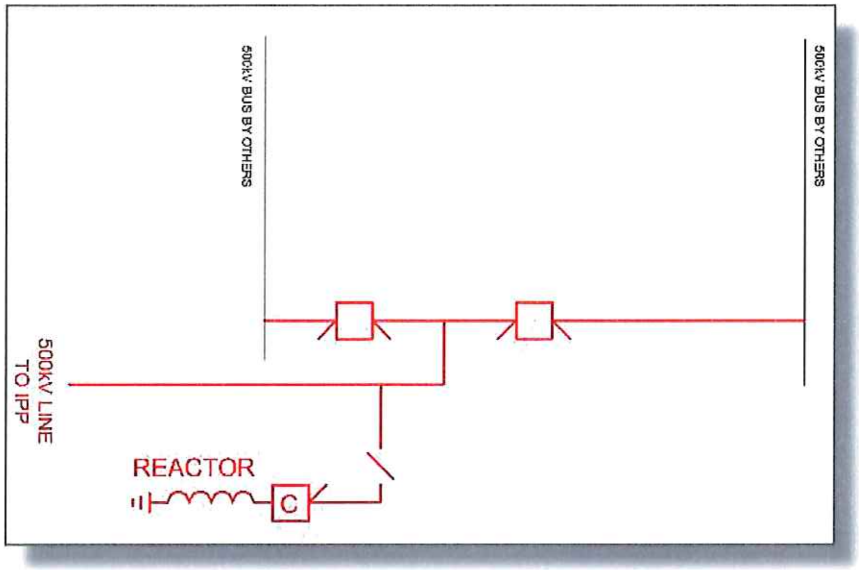


Figure 7.10 – Conceptual Layout of Robinson Summit Substation

7.4.2.2 IPP Substation

IPP is an existing 345/230 kV AC and 500 kV DC substation owned by the participants in the Intermountain Power Project. It is located 10 miles north of Delta, Utah. One-line diagrams are included for both the 500 kV and 345 kV East Project alternatives. In addition, the required equipment additions for the Robinson Summit-IPP project and IPP-Mona project are depicted with different color coding to distinguish between the two projects. The IPP Substation additions for the Robinson Summit-IPP project at 500 kV are estimated to be approximately $92.0 million. Similarly, at 345 kV the estimated cost is approximately $9.7 million. The IPP Substation additions for the IPP-Mona 345 kV project are estimated at approximately $8.0 million.

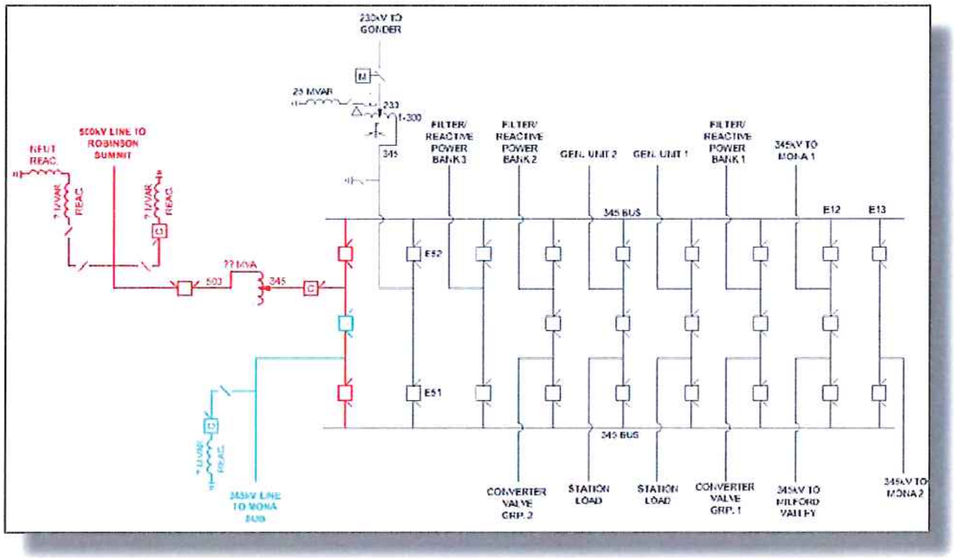


Figure 7.11 – Conceptual Layout of 500 kV Interconnection at IPP

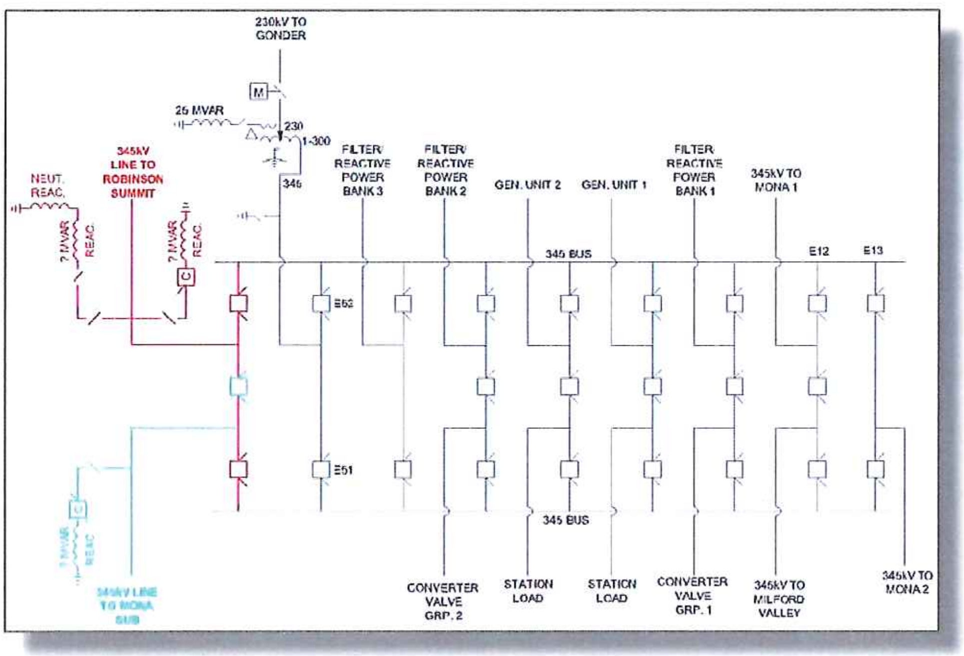


Figure 7.12 – Conceptual Layout of 345 kV Interconnection at IPP

7.4.2.3 Mona Substation

Mona Substation is an existing 345 kV substation located 3 miles west of Mona, Utah. The Mona Substation improvements associated with the East Project are estimated at $4.0 million.

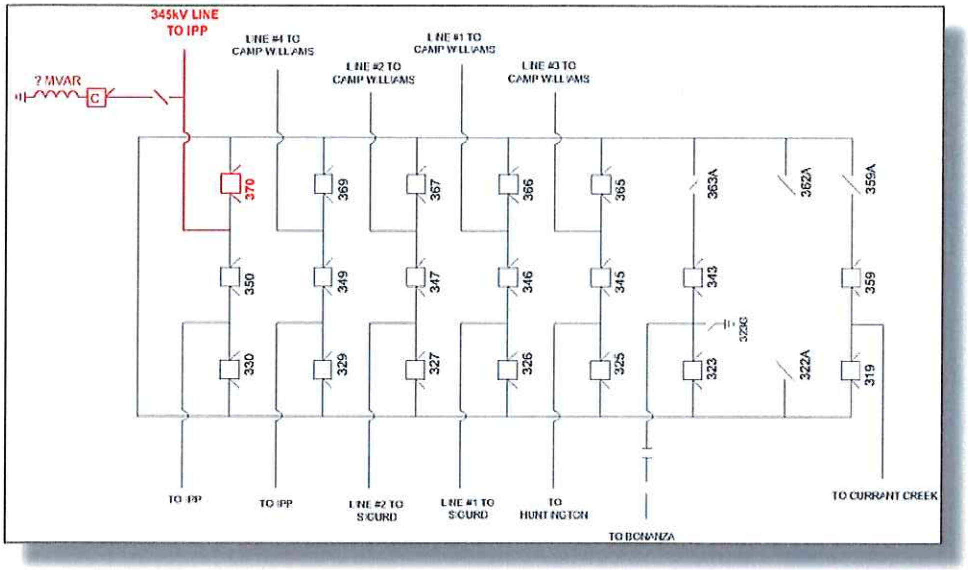


Figure 7.13 – Conceptual Layout of Mona Substation

7.4.3 South Project Substations

7.4.3.1 Anaconda-Moly Substation

Anaconda-Moly is an existing 230/120 kV substation on the NV Energy system. It is located approximately 18 miles north of Tonopah, Nevada. The following one-line diagram depicts Anaconda-Moly Substation. Those facilities color coded in black are existing and are not included in cost estimates for the South Project. The facilities color coded in red are new additions associated with the South Project and are included in the South Project cost estimates. South Project facility additions at Anaconda-Moly Substation are estimated at approximately $12.1 million. These improvements are only required if the RTI "West Tie-South" is not built prior to or in conjunction with the South Project.

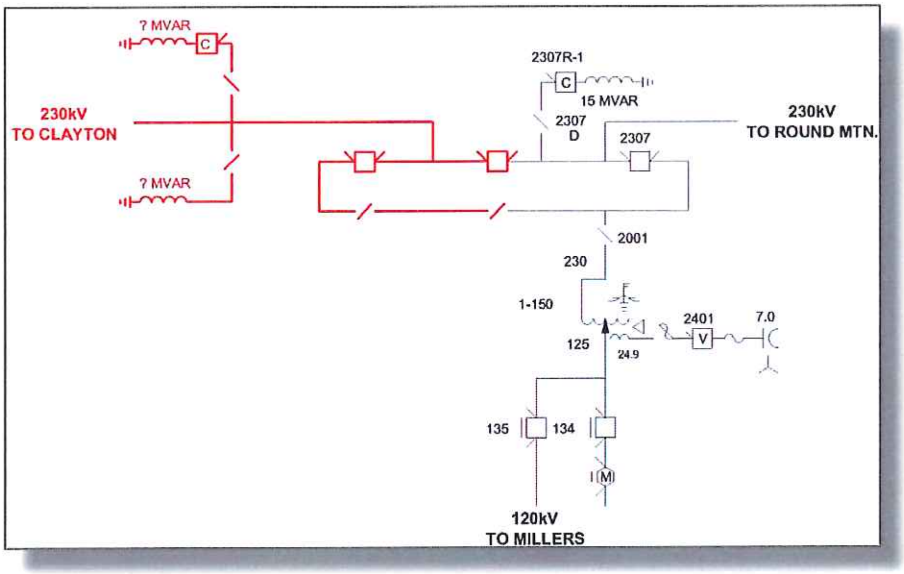


Figure 7.14 – Conceptual Layout of Anaconda-Moly Substation

7.4.3.2 Clayton Substation

Clayton Substation is a new 500/230 kV substation approximately 26 miles southwest of Tonopah, Nevada. Clayton Substation is only required if the RTI "West Tie-South" line is not built prior to or in conjunction with the South Project. The facilities are broken up into two groupings for cost estimating purposes; 1) Initial construction and 2) Future line to Pahrump. The initial construction of Clayton Substation is estimated at approximately $75.4 million. The future improvements at Clayton Substation for a 500 kV line to Pahrump are estimated at approximately $17.7 million.

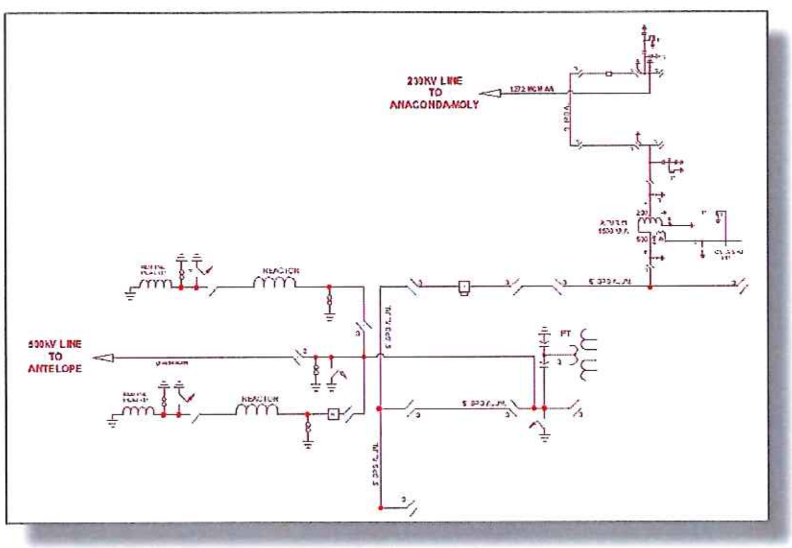


Figure 7.15 – Conceptual Layout of 500 kV Interconnection at Clayton Substation

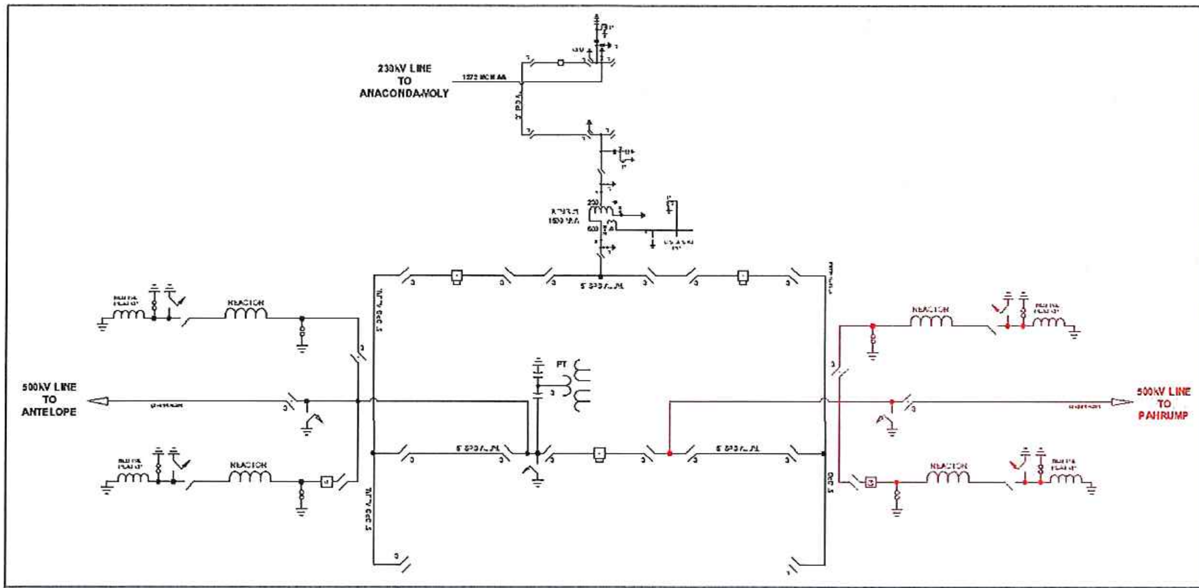


Figure 7.16 – Conceptual Layout of Interconnection at Clayton Sub; Continuation to Pahrump Sub

7.4.3.3 Lida Substation

Lida Substation is a new 500 kV substation approximately 34 miles south of Tonopah, Nevada. The proposed location of Lida Substation is approximately 9 miles northwest of the junction of Highway #266 and Highway #95. Lida Substation is the northern terminus of the South Project if the RTI "West Tie-South" line is built prior to or in conjunction with the South Project. The facilities at Lida Substation are estimated at approximately $30.3 million.

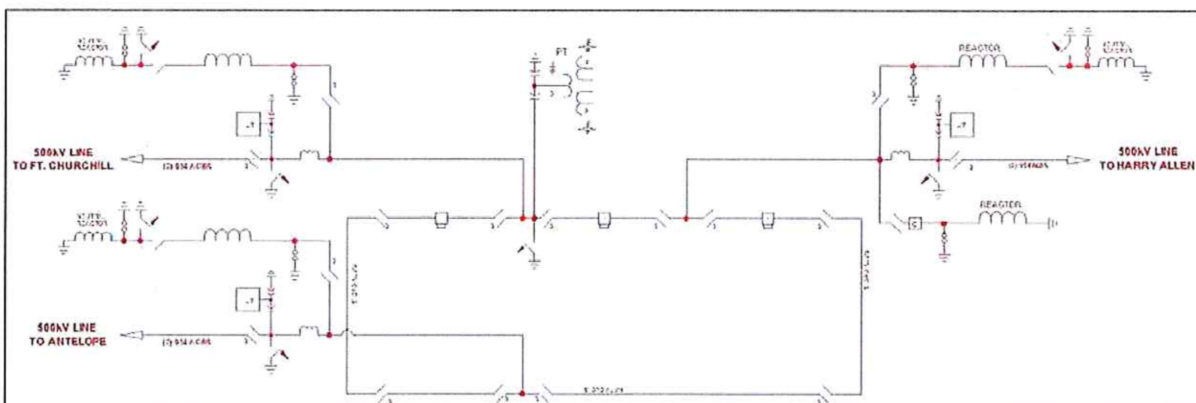


Figure 7.17 – Conceptual Layout of Lida Substation

7.4.3.4 Ridgecrest Substation

Ridgecrest Substation is a future collector substation for renewable generation approximately 12 miles northwest of Ridgecrest, California. This report assumes all improvements at Ridgecrest Substation would be funded by the renewable generation developers necessitating the facility. As a result, the $42.0 million estimate for Ridgecrest Substation is not included into the initial cost estimate for evaluation, but is referenced herein for informational purposes.

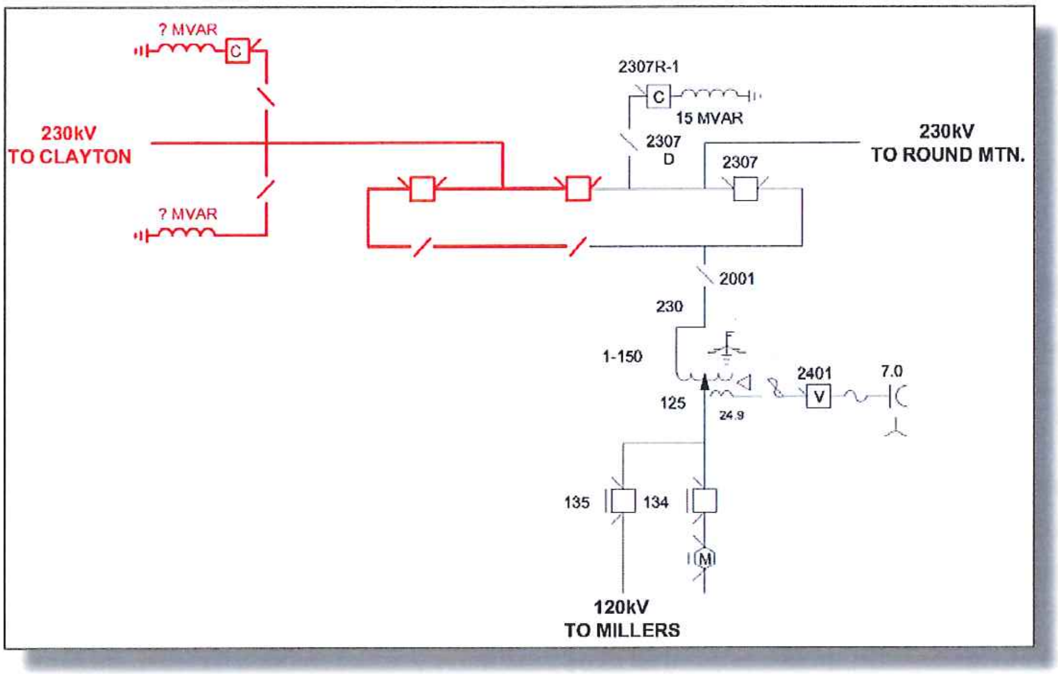


Figure 7.18 – Conceptual Layout of Ridgecrest Substation

7.4.3.5 Antelope Substation

Antelope is an existing 500/230 kV substation on the Southern California Edison system. It is located approximately 8 miles west of Lancaster, California. No information is readily available with regard to the existing electrical configuration at Antelope Substation. The one-line depicts the electrical equipment that is included in the cost estimate. The required additional facilities at Antelope Substation are estimated at approximately $10.9 million.

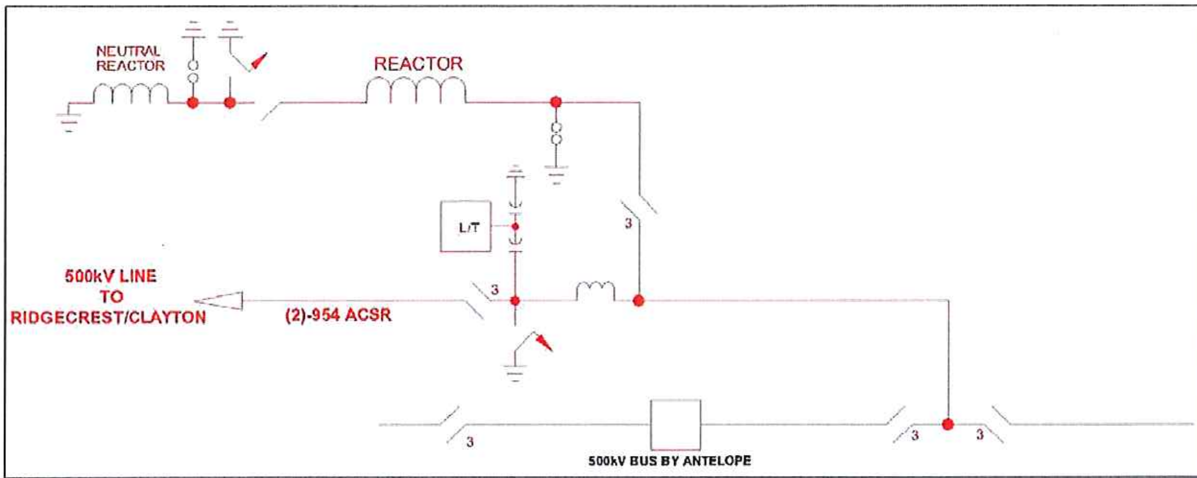


Figure 7.19 – Conceptual Layout of Antelope Substation

7.4.3.6 Pahrump Substation

Pahrump is a proposed VEA 500 kV substation. The proposed electrical configuration is unknown. The one-line depicts the electrical equipment that is included in the cost estimate. The required additional facilities at Pahrump Substation are estimated at approximately $17.9 million.

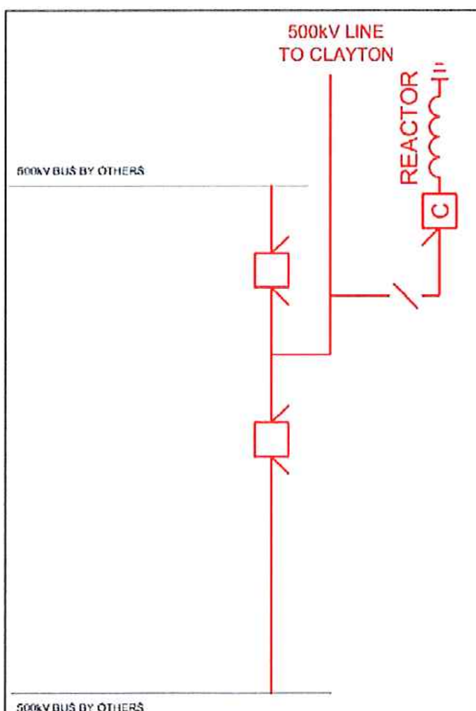


Figure 7.20 – Conceptual Layout of Pahrump Substation

Project Option: Substation Name	Substation Estimated Cost[1]	Comments
North Project:		
North Fernley	$16,000,000	Used for Alternative 1, North Fernley to Viewland
Oreana	$8,900,000	Used for Alternative 2, Oreana to Viewland
San Emidio	$64,000,000	Not used in total project estimate; assumes generation developer funding
Viewland (1)	$16,100,000	Assumes Viewland Substation is built from a greenfield site
Viewland (2)	$12,900,000	Assumes Viewland Substation is developed as part of the Viewland-Olinda project
Phase Shifter	$3,200,000	Relocation of the NVE Bordertown Phase Shifting Transformer to Hilltop Substation
East Project:		
Robinson Summit (345)	$13,000,000	Robinson Summit Substation 345 kV additions
Robinson Summit (500)	$17,900,000	Robinson Summit Substation 500 kV additions
IPP (Robinson 345)	$9,700,000	IPP Substation, Robinson Summit 345 kV additions
IPP (Robinson 500)	$92,000,000	IPP Substation, Robinson Summit 500 kV additions
IPP (Mona 500)	$8,000,000	IPP Substation, Mona 345 kV additions
Mona	$4,000,000	Mona Substation 345 kV additions
South Project:		
Anaconda Moly	$12,100,000	Anaconda Moly Substation 230 kV additions
Clayton (1)	$75,350,000	Clayton Substation initial construction
Clayton (2)	$17,650,000	Clayton Substation futrue addition to Pahrump
Lida	$30,300,000	Lida Substation initial construction
Ridgecrest	$42,000,000	Not used in total project estimate; assumes generation developer funding
Antelope	$10,900,000	Antelope Substation 500 kV additions
Pahrump Sub	$17,900,000	Pahrump Substation additions for future 500 kV addition

[1] *Costs are rounded*

Table 7.2 – Substation Cost Estimates Summary

Section 8: Report Conclusions and Recommendations



SECTION 8: REPORT CONCLUSIONS & RECOMMENDATIONS

8.1 SECTION PURPOSE

The purpose of this section is to summarize the conclusions and to discuss the next steps that would be required to further support these projects.

8.2 REPORT SUMMARY

This report provides a macroscopic view of proposed solutions to the existing limited transmission export capacity for renewable energy out of the state of Nevada. It is rare to complete routing of multiple projects concurrently due to the order of magnitude of data collection and regulatory and policy issues. Typically a line is routed to address more micro-level needs such as serving specific geographic areas, or transmitting power from an individual generator, or collection of renewable energy developments. However, in the case of this effort, the direction was given to develop preferred transmission line routing to allow for increased export capabilities out of Nevada into neighboring states, while concurrently facilitating the development of renewable energy collector systems within the state of Nevada. In this instance, it was also incumbent of the team to not duplicate efforts by others, including NV Energy and the previous work completed by RETAAC, as well as private transmission developers. To accomplish this, it was necessary to look at the state as a whole, consider all the renewable energy zones, and evaluate the most efficient means of connecting those zones to the current renewable electric energy load centers. To this end, the team determined the proposed three projects that are presented in the Executive Summary, and are explained throughout this report. It must be noted that these recommendations are based on as current of data as possible at the point of report release. However, the renewable energy market and the electric grid regulatory environment are ever evolving. This is evidenced in the impacts of FERC Order No. 1000 and the issues that are now being assessed by utilities nationwide. In addition, RPS requirements are being revised concurrently with utilities trying to meet those requirements while maintaining system grid integrity.

This report provides a comprehensive evaluation of all of the issues that were considered. In order to maintain continuity of these recommendations, and to keep the projects as current and responsive to the need as possible, it will be critical to sustain momentum and advance the projects forward. The information herein provides a guide of what will be required for the next steps of this effort.

The following recommendations are presented in as much of a chronological order as is practical. It should be recognized that in some cases these steps might not occur in the precise sequence indicated, or will require concurrent activity. The project sponsor will need to balance the timing and associated cost expenditures of each activity specified in Subsections 8.3 through 8.11 as this process proceeds.

8.3 OUTREACH & COORDINATION WITH REGIONAL & PROPOSED INTERSTATE TRANSMISSION PROJECTS

Extensive outreach was conducted throughout this study to gain knowledge of other transmission efforts, maintain an understanding of their progress, and establish open communication with regard to the obstacles facing them. It was important to have this understanding to ensure that the planning and routing of the proposed projects herein did not conflict with other planned capacity additions where possible. As an example, while the proposed projects do not duplicate planned capacity additions, the North Project does enhance one of those proposed projects. The result is a more robust capacity addition to the grid in the event both the LMUD and North Project are constructed. Specific to this scenario, it is even more critical to maintain open communication with the LMUD team and maintain a close understanding of their project status.

Another project that warrants continued monitoring and communication is the proposed Great Basin HVDC project. While the three proposed projects provided in this report are not tied to this effort in any way, there is an opportunity to track the success of and support the HVDC project. This project, if completed, would add additional capacity to the overall improvement of transmission export out of Nevada.

Other regional projects that may have less direct impact to these proposed projects also warrant continued monitoring and communication.

8.4 DISCUSSION OF POTENTIAL BENEFITS TO NEVADA & BUSINESS CASE DEVELOPMENT

As NEAC moves forward with exploration of the Project Proponent Team and financing structure, it will be critical to maintain clarity that this project will have a life expectancy of 50 years or more, and would bring extensive economic benefits to the state of Nevada as well as support the development and enhancement of the technology base for the renewable energy development within the State. These projects could be a key piece of infrastructure for Nevada, representing not only a new source of renewable energy export but substantially greater reliability and energy security for both Nevada and California.

A thorough economic evaluation should be completed in order to identify the specific benefits to Nevada. The following parameters, at a minimum, need to be investigated to support that evaluation:

- Construction Labor and associated economic benefits
- Intellectual Capital Development as a base resource
- Property Tax
- Sales Tax
- Long Term Job Creation
- Leveraging of economic activity

The economic evaluation could then be used to complete a more stringent and structured business case development. At a minimum, the following should be included in the business case development:

- Review of potential market and establishment of subscription potential of each project
- Development of financial structure to support the capital funding for each project and for projects in total
- Due Diligence review of capital cost requirements and schedules
- Development of administrative and operating cost projections
- Projections of transmission rates; both Federal (FERC) and State level
- Sensitivity Analysis of transmission rates; both FERC and State level
- Investigation of the option of a public / private FERC regulated transmission company

8.5 FEDERAL & REGIONAL TRANSMISSION MONITORING & INVOLVEMENT

As the NEAC Board proceeds with one or more of these projects, it will be critical to remain vigilant and informed regarding the political and regulatory issues impacting the electric transmission industry. The current issues surrounding the FERC Order 1000 and the pending regionalized transmission planning will be a critical factor that impacts the proposed project(s). In addition, policy and requirement changes within the EPA, DOE, and the FERC and State Agencies regarding routing, permitting, and cost recovery of transmission lines will greatly affect the viability of all transmission projects. It will be beneficial to engage with the State Energy Offices, the State Public Utility Commissions, FERC, WECC and other regional transmission entities who affect and understand transmission policy. Considerable outreach has been conducted with these agencies early in the project by both the project team and the Nevada State Energy Office. In order to maintain the momentum that was created through the early efforts of outreach, it will be necessary to continue with these communications.

8.6 SOLIDIFY DISCUSSIONS WITH CALIFORNIA UTILITIES / DEFINE PURCHASE OPPORTUNITIES

Moving forward with this effort will require collaboration with the power purchasing utilities in California. The RETAAC I and II evaluations, the ongoing OATT and OASIS tracking of renewable interconnection requests, and the continuous discussions with renewable energy developers show that there is an abundance of resources in Nevada. One of the next steps will be to consolidate the interest of entities to purchase the power generated from these resources. The Tri Sage Team was tasked with the development of export transmission line routes. In order to optimize the narrowing of these routes to ensure that they terminate in areas of strong potential power purchasing requirements, discussions were initiated with the power purchasing utilities. These discussions concluded that there is interest for purchasing these resources. However, a much more detailed effort will be required by NEAC to move the effort forward by engaging potential purchasers, including the public and investor owned utilities. As an example, the South Project proposes a termination at the Antelope Substation. This substation is owned and operated by Southern California Edison (CSE). This interconnection facilitates the delivery of energy to many potential purchasers of renewable energy in the California market.

Ultimately, a process similar to the RTI presently being conducted by NV Energy will likely be required to consolidate the market demand and commitment. This entails soliciting interest of renewable energy developers and/or buyers to commit to long-term contract use of the intended transmission projects.

8.7 PROJECT FINANCING DISCUSSION

The critical issue moving forward with one or all of these proposed transmission projects will be finding a suitable project sponsor. This will define and provide focus to how the project moves forward, from a planning and implementation standpoint as well as from a financing structure and governance.

There will be opportunities to create project financing structures. Several private investment firms find this type of investment attractive, given the proper market and political conditions. Private investors have interest in the development of transmission projects and, based on some preliminary discussions, there may be interest in these proposed NEAC transmission projects. It is important to note that there is significant uncertainty in renewable energy development and private investment in transmission as a result of not having clear understanding of the California RPS market. Investors are operating on the current publically announced position of California not having a large interest in importing renewable energy, and as a consequence, transmission needs are presumably less critical to California.

The political and policy issues need to be addressed to promote the necessary interest in the market and to develop the business case and financial analysis to support the development of the proposed projects.

There are multiple issues that any investor will want to clearly understand to allow for proper evaluation of the project costs versus benefits of the investment. The primary issues to be evaluated before any financing plans can be developed include:

- Permitting issues
- Regulatory & policy issues
- Market demand to support the project(s)
- Operational capabilities (i.e. Grid operations and capacity ratings)

A critical element of any project financing is the development of a financial model of costs and revenues and this should be developed before proceeding with the major expenditure of final path ratings, permitting, final design and right-of-way acquisition. This model will be instrumental in performing a sensitivity analysis for all assumptions and should be a critical element for development of financing alternatives.

8.8 TRANSMISSION PROJECT RATINGS

The WECC is the regional entity responsible for coordinating and ensuring bulk electric system reliability in the Western United States. WECC provides an environment for coordinating the operating and planning activities of its members. WECC is geographically the largest and most diverse of the eight regional entities that have Delegation Agreements with the North American Electric Reliability Corporation (NERC). Membership in WECC is open to all stakeholders with an interest in the operation of the bulk electric system in the Western Interconnection.

WECC requires a three phase path rating process that is a comprehensive technical planning study to define the transfer limit that a new transmission line (or lines) can achieve without interfering with the reliability or stability of other lines in the western interconnection. In addition to technical modeling, the path rating process requires a peer review by all interested transmission providers and other stakeholders.

The WECC process facilitates a variety of studies and assessments required for the reliable planning and operation of the bulk electric system in the Western Interconnection. Included in these activities are long-term planning studies on five- and ten-year horizons, congestion studies, and assessments of loads and resources.

Within WECC, there are multiple Subregional Planning groups. The Sierra Subregional Planning Group (SSPG) is a division of the WestConnect organization. The SSPG is a joint, high voltage transmission system planning forum for the purpose of assuring a high degree of reliability in the planning, development and operation of the high voltage transmission system in the Northern California and Northern Nevada region. This is in accordance with the Joint Transmission Access Principles and the Electric Transmission Service Policy Statement, dated Dec. 16, 1991[1].

Submittal of the project data to the SSPG initiates a portion of the regional planning process required to ultimately obtain WECC ratings. This announces the project(s) to the regional stakeholders and facilitates market interest development for potential transmission users (i.e. renewable energy developers and other transmission users). The process requires decisions regarding specific technical parameters to support computer software based transmission modeling. The ultimate WECC Rating parameters will include project voltage, line length, conductor size, phase spacing, as well as transformer and shunt reactor sizing.

The projects presented herein were submitted to the SSPG on January 20, 2012. Due to the changes that are occurring among the WECC sub-regional planning groups related to FERC Order No. 1000, there was some question as to exactly how the coordination between the sub-regional groups will be performed. The three NEAC projects collectively span into multiple sub-regional territories. It was determined that filing with the sub-regional group in which each project originated would be the conventional, and most logical filing at this time. This turned out to be the SSPG for each of the proposed projects. Following initial discussions with the Chairman of the SSPG, it is understood that once filed, distribution of the project information among other sub-regional and Transmission Expansion Policy Planning Committee (TEPPC) groups will be facilitated by SSPG. However, it is still unclear how the California planning groups will be involved in the electric rating effort. This will be critical to primarily the South Project. For this initial filing with the SSPG, the NSOE has sent a copy of the WECC filing to the CAISO for reference and action, as they deem necessary. Follow-up and support through this process will be critical.

This effort will require technical support and attention in order to address issues as they arise. Due to the changes occurring within WECC and the SSPG in response to FERC Order No. 1000,

[1] Information obtained from the official WestConnect Web Site; update 2012.

the exact rating process and agency involvement that will occur is unknown. As such, it will be necessary to closely track progress and provide input as opportunity or need arises.

8.9 ENVIRONMENTAL APPLICATION PREPARATION

These projects will be subjected to extensive environmental permitting in order to receive approval for construction. Most notably will be the National Environmental Policy Act (NEPA) process. Under NEPA, each of the three proposed projects will be subjected to an Environmental Impact Statement (EIS). This federal process is an assessment of the possible positive or negative impacts that a proposed project may have on the environment, including social and economic aspects. The purpose of the assessment is to ensure that decision makers consider the ensuing environmental impacts when deciding whether to proceed with a project. This effort can take anywhere from 18 months to 6 years.

In addition to the NEPA process, the North and South Projects will be subject to the California Environmental Quality Act (CEQA) with mandated actions that all state and local agencies must take to advance the policy. Specifically, for any project under CEQA's jurisdiction with potentially significant environmental impacts, agencies must identify mitigation measures and possible alternatives by preparing an Environmental Impact Report (EIR), and must approve projects with feasible mitigation measures as the environmentally superior alternative.

For all projects, in addition to NEPA and CEQA (where applicable), there are many other permitting processes at the state and local levels that will be required to be followed. These include permits for stream and wetland impacts, storm water management, air and dust control, encroachment, special use, etc. For the immediate next steps, the focus should be on the NEPA and CEQA application filings.

Recently, the Federal Government has engaged with facilitating expedited review of the federal level permitting. This was a result of the delays that were occurring in securing the needed statutory reviews, permits, and consultations that threatened timely completion of many transmission lines nationwide. Recognizing the need for Federal agencies to coordinate their efforts on transmission and to quickly respond to issues, nine Federal agencies have been closely coordinating their review of electric transmission on Federal lands under a joint Memorandum of Understanding (MOU) executed in 2009.

Additionally, the President recently issued a memorandum stating that agencies should ensure that their processes for reviewing infrastructure proposals work efficiently to protect our environment, provide for public participation and certainty of process, ensure safety, and support vital economic growth.

Building on the cooperation developed through the MOU[2], and in response to the Presidential Memorandum, the Administration has created a Rapid Response Team for Transmission (RRTT). The RRTT aims to improve the overall quality and timeliness of electric transmission infrastructure permitting, review, and consultation by the Federal government on both Federal and non-Federal lands through:

- Coordinating statutory permitting, review, and consultation schedules and processes among involved Federal and state agencies, as appropriate, through Integrated Federal Planning;
- Applying a uniform and consistent approach to consultations with Tribal governments; and,
- Resolving interagency conflicts and ensuring that all involved agencies are fully engaged and meeting timelines.

Participating Agencies include: the Department of Agriculture, the Department of Commerce, the Department of Defense, the Department of Energy, the Department of Interior, the Environmental Protection Agency, the Federal Electric Regulatory Commission, the Advisory Council on Historic Preservation, and the White House Council on Environmental Quality.

The next steps for the permitting of these projects should consider the preparation of the NEPA (and CEQA for the North and South Projects) applications, and coordinating with the RRTT to establish these projects as ones needed the rapid response assistance.

8.10 PRELIMINARY AND FINAL DESIGN REQUIREMENTS

Conceptual designs have been completed within this effort at the level necessary to establish routing sufficient to evaluate land use requirements. In addition, preliminary engineering level cost estimates have been developed for each of the projects. All of this is necessary to move forward into the next phase of these projects. However, it is critical to understand that a final level design of each of the transmission lines and substations will be required. This effort will need to be initiated well into the permitting effort, once a good understanding of the final route alignments is established.

Final design will include the preparation of structure and conductor studies to determine the most optimum structure and conductor types to be used; design level surveying and mapping; modeling and line optimization; final structure sizing and analysis; complete material lists development; finalized plan and profile development; stringing and sagging calculations; final staking drawings; and preparation of a final construction package. This effort will also include

2 Memorandum Of Understanding among the U.S. Department Of Agriculture, Department Of Commerce, Department Of Defense, Department Of Energy, Environmental Protection Agency, The Council On Environmental Quality, The Federal Energy Regulatory Commission, The Advisory Council On Historic Preservation, And Department Of The Interior Regarding Coordination In Federal Agency Review Of Electric Transmission Facilities On Federal Land; Executed October 23, 2009

the preparation and distribution of all necessary bid documents, along with the evaluation of submitted bids to provide a final recommendation to the project proponent as to the recommended contractor for the work.

8.11 PROPERTY AND RIGHT-OF-WAY ACQUISITION

Property acquisition will be one of the key elements that holds one of the greatest potentials for delaying a project. NEAC, as it moves forward in establishing the project team, must consider the need to have a partner who holds the right of eminent domain, also referred to as condemnation. This right is granted to utilities that have service territory in the area and are pursuing a project for public use, or, also afforded this right are governmental agencies. As an example in the case of Nevada, the State Department of Transportation (NDOT) frequently utilizes its right of eminent domain. This right will allow the project proponent to condemn a property in the event they are not able to reach a negotiated settlement of fair market value for a right-of-way or easement. A condemnation proceeding typically involves an assessment of how the project, in this case a high-voltage transmission line, will impact the remainder of the owner's property in question. Fair market value of the actual right-of-way that is being acquired is not typically a point of discussion at this stage. In some cases, a power line that takes a right-of-way along a property line arguably leaves the remaining property with no remaining economic value. This is the belief of many land owners. Conversely, the condemning agency or project proponent will view that the land is only encumbered to a minor extent and will therefore not impact its overall economic value. How these issues are resolved will set the stage for how quickly the project construction can begin. In many cases, courts allow construction to begin once condemnation is filed with the understanding that the land will be taken and the court will settle the issue of land owner compensation.

As a criterion in the routing of the lines proposed herein, the team opted to avoid private land whenever possible. However, there is still much land that is private. One of the next steps will be to establish land ownership identification. This will not need to be completed until the confidence level of the proposed routes becomes higher. Typically this will occur once the WECC path ratings have been completed and the NEPA / CEQA permitting is well underway. Monitoring of the permitting process will allow the project proponent to keep a pulse on the public and agencies acceptance of the preferred routing. Typically, actual land acquisition will not be initiated until the NEPA Record of Decision has been issued. In the event of a tight schedule, some proponents are willing to take a risk and initiate the negotiations prior to final permitting. This will all require a close review and coordination with the environmental consultant.

Appendix A: Reference Documents

APPENDIX A-1

TRANSMISSION REFERENCES from RETAAC, NVE IRP's, and PUCN FILINGS

Notable Transmission Info Referenced from RETAAC Phase 2 Report, NV Energy North and South IRP's, & PUCN Filings

Source Report	PDF Page	Transmission Improvement or Topic	Topic Discussed
RETAAC-2	8	All Transmission Ties	Table of Economic Feasibility Ranking
RETAAC-2	27	All Transmission Ties	Intertie line lengths
RETAAC-2	31	All Transmission Ties	Intertie Map w/Existing Transmission grid
RETAAC-2	32	All Transmission Ties	Intertie Map w/Renewal Resource Areas
RETAAC-2	37	All Transmission Ties	Transmission Line Cost Estimates $'s/mile
RETAAC-2	39	All Transmission Ties	Transmission Line Ranking Table
RETAAC-2	40	All Transmission Ties	MW Potential by Renewable Zone
RETAAC-2	46	All Transmission Ties	Transmission Monthly Rates for various Utilization Factors in $'s/MW
RETAAC-2	49	All Transmission Ties	Transmission Monthly Rates for various Utilization Factors in $'s/MW
RETAAC-2	51	All Transmission Ties	Transmission Intertie Ranking by Economic Feasibility
RETAAC-2	54	All Transmission Ties	Export Transmission Projects in Table format
RETAAC-2	55	All Transmission Ties	Map of Exporting Transmission Projects
RETAAC-2	56	All Transmission Ties	Descriptive Paragraphs of Exporting Transmission Projects
RETAAC-2	58	All Transmission Ties	Export Capability of Existing Transmission Facilities in Table format
RETAAC-2	59	All Transmission Ties	Map of Export Capability of Existing Transmission Facilities
RETAAC-2	62	South	Discussion of N-S Constraint in Las Vegas Area
RETAAC-2	80	All Transmission Ties	Renewable energy Zone Prioritization Criteria Detail Table
RETAAC-2	81	WAPA SOI	Four phases of WAPA's improvments described
RETAAC-2	87	WAPA Phase 1	Harry Allen-Northwest-Amagosa Valley 500 kV Project Description
RETAAC-2	87	WAPA Phase 2	Desert Rock-Mead 500 kV Project Description
RETAAC-2	88	WAPA Phase 3	Amargosa Valley-Blackhawk 500 kV Project Description
RETAAC-2	88	WAPA Phase 4	Blackhawk-Raven 500 kV Project Description
RETAAC-2	95	WAPA SOI	Map of Transmission Projects covered in SOI

Notable Transmission Info Referenced from RETAAC Phase 2 Report, NV Energy North and South IRP's, & PUCN Filings

Source Report	PDF Page	Transmission Improvement or Topic	Topic Discussed
RETAAC-2	97	WAPA SOI	Spreadsheet w/Capacity and cost for SOI Projects
SPPIRP-V2(PUCN Dkt. # 10-07003)	17	Generator Retirements	Table of recommended generation to be retired during action plan
SPPIRP-V2(PUCN Dkt. # 10-07003)	18	Transmission Action Plan	Action plan for transmission & delayed transmission items
SPPIRP-V2(PUCN Dkt. # 10-07003)	241	Whalen Testimony	Start of Whalen testimony
SPPIRP-V2(PUCN Dkt. # 10-07003)	243	Carson Lake Project	Description of Fallon 230 kV reinforcements
SPPIRP-V2(PUCN Dkt. # 10-07003)	244	Bordertown-Cal Sub	Description of Bordertown to Cal Sub 120 kV line and other changes for Bordertown Hilltop 345 kV line
SPPIRP-V2(PUCN Dkt. # 10-07003)	245	Blackhawk Substation	Explanation of Blackhawk Project delay
SPPIRP-V2(PUCN Dkt. # 10-07003)	246	Blackhawk-Mira Loma	Explanation of Blackhawk-Mira Loma 345 kV project delay
SPPIRP-V2(PUCN Dkt. # 10-07003)	246	Plumas-Sierra Interconnection	Explanation of cancellation of the Plumas-Sierra Interconnection
SPPIRP-V2(PUCN Dkt. # 10-07003)	247	Eldorado Valley	Whalen testimony regarding most desirable location for importing or exporting renewable energy
SPPIRP-V10(PUCN Dkt. # 10-07003)	8	Generator Capabilites	Table of SPP generator capabilities
SPPIRP-V10(PUCN Dkt. # 10-07003)	21	SPP Power Agreements	Table of SPP Power related agreements
SPPIRP-V10(PUCN Dkt. # 10-07003)	42	Renewable Energy Sources	Map of NV Energy Renewable Energy Sources
SPPIRP-V10(PUCN Dkt. # 10-07003)	45	Carson Lake Project	Detailed Description of the Carson Lake/Fallon 230 kV Reinforcements
SPPIRP-V10(PUCN Dkt. # 10-07003)	48	Carson Lake Project	Carson Lake Project One-Line Diagram
SPPIRP-V10(PUCN Dkt. # 10-07003)	49	Bordertown-Cal Sub	Detailed Discussion of outage that drive need 7 potential relocation of Bordertown Phase Shifter
SPPIRP-V10(PUCN Dkt. # 10-07003)	51	Bordertown-Cal Sub	One-Line Diagram of Bordertown-Cal Sub project
SPPIRP-V10(PUCN Dkt. # 10-07003)	54	Blackhawk Project	Detailed Description of Blackhawk project w/o any West Tie - South improvements
SPPIRP-V10(PUCN Dkt. # 10-07003)	56	Blackhawk Xfmr #2	Timing description
SPPIRP-V10(PUCN Dkt. # 10-07003)	56	Blackhawk-Mira Loma	Explanation of Blackhawk-Mira Loma 345 kV project delay
SPPIRP-V10(PUCN Dkt. # 10-07003)	56	Plumas-Sierra Interconnection	Explanation of cancellation of the Plumas-Sierra Interconnection
SPPIRP-V10(PUCN Dkt. # 10-07003)	58	IRP Action Plan Cash Flow	Table of the three year action plan transmission project cash flow
SPPIRP-V10(PUCN Dkt. # 10-07003)	59	ON Line	Description of two tracks ON Line can take depending on GBT

Notable Transmission Info Referenced from RETAAC Phase 2 Report, NV Energy North and South IRP's, & PUCN Filings

Source Report	PDF Page	Transmission Improvement or Topic	Topic Discussed
SPPIRP-V10(PUCN Dkt. # 10-07003)	60	West Tie Rating	Explanation that the West Tie has not been rated due to uncertainty in generation additions & timing
SPPIRP-V10(PUCN Dkt. # 10-07003)	61	Existing Tielines	Map showing existing tielines and WECC Path numbers
SPPIRP-V10(PUCN Dkt. # 10-07003)	61	Idaho-Sierra Path #16	Description and non-simultaneous ratings
SPPIRP-V10(PUCN Dkt. # 10-07003)	61	PG&E-Sierra Path #24	Description and non-simultaneous ratings
SPPIRP-V10(PUCN Dkt. # 10-07003)	61	Utah Ties - Path #32	Description and non-simultaneous ratings
SPPIRP-V10(PUCN Dkt. # 10-07003)	61	Silver Peak-Control Path #52	Description and non-simultaneous ratings
SPPIRP-V10(PUCN Dkt. # 10-07003)	61	Alturas Path #76	Description and non-simultaneous ratings
SPPIRP-V10(PUCN Dkt. # 10-07003)	63	SPP Max Import	Discussion of SPP Max Import limits by year
SPPIRP-V10(PUCN Dkt. # 10-07003)	63	SPP Max Export	Discussion of SPP Max Export limits by year
SPPIRP-V10(PUCN Dkt. # 10-07003)	64	SPP Transmission Limitations	System impact for Tracy-Valley Road 345 kV Line loss discussed
SPPIRP-V10(PUCN Dkt. # 10-07003)	64	SPP Transmission Limitations	West Tie support of Reno-Carson voltage discussed
SPPIRP-V10(PUCN Dkt. # 10-07003)	65	SPP Transmission Limitations	Ft. Churchill generation as "must run" is discussed during high Carson area loads
SPPIRP-V10(PUCN Dkt. # 10-07003)	65	SPP Transmission Limitations	Tracy-Valley Rd 345 kV line outage discussed under heavy east-west transfers
SPPIRP-V10(PUCN Dkt. # 10-07003)	65	Bordertown-Cal Sub	Tracy-Valley Rd 345 kV line outage discussed under heavy east-west transfers
SPPIRP-V10(PUCN Dkt. # 10-07003)	65	Tracy-Ft Sage	Tracy-Valley Rd 345 kV line outage discussed under heavy east-west transfers
SPPIRP-V10(PUCN Dkt. # 10-07003)	66	SPP Import Obligations	Table of SPP long term transmission import obligations
SPPIRP-V10(PUCN Dkt. # 10-07003)	66	SPP Export Obligations	Table of SPP long term transmission export obligations
SPPIRP-V10(PUCN Dkt. # 10-07003)	67	FERC Impacts	A listing of FERC orders which have impacted SPP since the last IRP
SPPIRP-V10(PUCN Dkt. # 10-07003)	70	Planning Principles	Discussion of new FERC principles required in the transmission planning process
SPPIRP-V10(PUCN Dkt. # 10-07003)	73	WAPA SOI	Discussion and map of West Tie
SPPIRP-V10(PUCN Dkt. # 10-07003)	74	RECTP	Section covering the Renewable Energy Conceptual Transmission Plan
SPPIRP-V10(PUCN Dkt. # 10-07003)	75	Eldorado Valley	Whalen testimony regarding most desirable location for importing or exporting renewable energy
SPPIRP-V10(PUCN Dkt. # 10-07003)	76	RECTP	Map of RECTP

Notable Transmission Info Referenced from RETAAC Phase 2 Report, NV Energy North and South IRP's, & PUCN Filings

Source Report	PDF Page	Transmission Improvement or Topic	Topic Discussed
SPPIRP-V10(PUCN Dkt. # 10-07003)	77	2030 Studies	List of projects required to serve 2030 loads
SPPIRP-V10(PUCN Dkt. # 10-07003)	77	Bordertown-Cal Sub	Project requirement from 2030 load studies
SPPIRP-V10(PUCN Dkt. # 10-07003)	77	Blackhawk-Tracy	Project requirement from 2030 load studies
SPPIRP-V10(PUCN Dkt. # 10-07003)	77	Blackhawk Substation	Project requirement from 2030 load studies
SPPIRP-V10(PUCN Dkt. # 10-07003)	77	Blackhawk-Prison Hill	Project requirement from 2030 load studies
SPPIRP-V10(PUCN Dkt. # 10-07003)	77	Blackhawk-Dayton	Project requirement from 2030 load studies
SPPIRP-V10(PUCN Dkt. # 10-07003)	77	Tracy-Ft Sage	Project requirement from 2030 load studies
SPPIRP-V10(PUCN Dkt. # 10-07003)	77	Blackhawk-Mira Loma	Project requirement from 2030 load studies
SPPIRP-V10(PUCN Dkt. # 10-07003)	77	West Tie - South	Project requirement from 2030 load studies
SPPIRP-V10(PUCN Dkt. # 10-07003)	77	Blackhawk Project	Project requirement from 2030 load studies
SPPIRP-V13(PUCN Dkt. # 10-07003)	4	ON Line	Overview
SPPIRP-V13(PUCN Dkt. # 10-07003)	4	HA-NW-Amar	Overview
SPPIRP-V13(PUCN Dkt. # 10-07003)	5	Harry Allen-Eldorado	Overview
SPPIRP-V13(PUCN Dkt. # 10-07003)	6	West Tie - South	Amargosa-Blackhawk 500 kV dependent on LV area improvements
SPPIRP-V13(PUCN Dkt. # 10-07003)	7	All Transmission Ties	BLM Renewable Leases Map
SPPIRP-V13(PUCN Dkt. # 10-07003)	8	All Transmission Ties	NV Energy Interconnection Queue Map
SPPIRP-V13(PUCN Dkt. # 10-07003)	9	All Transmission Ties	NV Energy Renewable Energy Transmission Plan Map
SPPIRP-V13(PUCN Dkt. # 10-07003)	10	Collector	Renewable Energy Collector Lines Table
SPPIRP-V13(PUCN Dkt. # 10-07003)	11	Core Transmission	Table of Core Transmission Lines
SPPIRP-V13(PUCN Dkt. # 10-07003)	12	System Improvements	Table of System Improvement Lines and Substations
SPPIRP-V13(PUCN Dkt. # 10-07003)	14	On Line	Capacities and relationship w/Great Basin Transmission & SWIP North
SPPIRP-V13(PUCN Dkt. # 10-07003)	15	ON Line/SWIP - North	Eastern NV Renewable Map
SPPIRP-V13(PUCN Dkt. # 10-07003)	16	West Tie - South	Description w/Transformer Capacities

Notable Transmission Info Referenced from RETAAC Phase 2 Report, NV Energy North and South IRP's, & PUCN Filings

Source Report	PDF Page	Transmission Improvement or Topic	Topic Discussed
SPPIRP-V13(PUCN Dkt. # 10-07003)	16	Western transformations	Description of western voltage interfaces between 500-345-230 kv systems
SPPIRP-V13(PUCN Dkt. # 10-07003)	17	Tracy-Ft Sage	Description + phase shifter shuffle
SPPIRP-V13(PUCN Dkt. # 10-07003)	18	West Tie - North	Description + additional Blackhawk 345 kV lines
SPPIRP-V13(PUCN Dkt. # 10-07003)	22	ON Line	Description - Detailed
SPPIRP-V13(PUCN Dkt. # 10-07003)	22	Harry Allen-Eldorado	Description - Detailed
SPPIRP-V13(PUCN Dkt. # 10-07003)	22-23	HA-NW-Amar	Description - Detailed
SPPIRP-V13(PUCN Dkt. # 10-07003)	23-24	West Tie - South	Description - Detailed including transformation substations
SPPIRP-V13(PUCN Dkt. # 10-07003)	24	West Tie - North	Description - Detailed including transformation substations
SPPIRP-V13(PUCN Dkt. # 10-07003)	26	2030 Studies	Beginning of 2030 Transmission Studies
SPPIRP-V13(PUCN Dkt. # 10-07003)	28	Tracy-Ft Sage	Comparison of Tracy-Ft Sage 345 kV line vs. Black Hawk-Mira Loma 345 kV line(1st full paragraph)
SPPIRP-V13(PUCN Dkt. # 10-07003)	28	Tracy-Ft Sage	Rationale for Tracy-Ft Sage 345 kV line(next to last bullet point)
SPPIRP-V13(PUCN Dkt. # 10-07003)	64	System Max Interchange	Maximum Import and Export Cases
SPPIRP-V13(PUCN Dkt. # 10-07003)	80	Blackhawk	Explanation of Blackhawk Project Timing
SPPIRP-V13(PUCN Dkt. # 10-07003)	88	Carson Lake	Explanation of Carson Lake Project
SPPIRP-V13(PUCN Dkt. # 10-07003)	91	Bordertown-Cal Sub	Explanation of Bordertown - Cal Sub 120 kV Project
SPPIRP-V13(PUCN Dkt. # 10-07003)	116	Generator Capabilites	Generation Capability Tables
NPCIRP-V3(PUCN Dkt. # 10-02009)	96	Whalen Testimony	Start of Whalen testimony
NPCIRP-V3(PUCN Dkt. # 10-02009)	99	ON Line	Project description and GBT implications
NPCIRP-V3(PUCN Dkt. # 10-02009)	100	ON Line	Cost and ownership share
NPCIRP-V3(PUCN Dkt. # 10-02009)	101	ON Line	Capacity rating dependent on generation locations
NPCIRP-V3(PUCN Dkt. # 10-02009)	102	ON Line	Voltage problems at high flows
NPCIRP-V3(PUCN Dkt. # 10-02009)	102	ON Line	Need for Phase shifters and SVC
NPCIRP-V3(PUCN Dkt. # 10-02009)	103	ON Line	Accept 600 MW rating and delay Phase shifters and SVC

Notable Transmission Info Referenced from RETAAC Phase 2 Report, NV Energy North and South IRP's, & PUCN Filings

Source Report	PDF Page	Transmission Improvement or Topic	Topic Discussed
NPCIRP-V3(PUCN Dkt. # 10-02009)	104	West Tie - South	Testimony about impact of permit problems through DNWR
NPCIRP-V3(PUCN Dkt. # 10-02009)	104	ON Line	Testimony regarding preference for ON Line vs. West Tie
NPCIRP-V3(PUCN Dkt. # 10-02009)	106	Northwest-Harry Allen 2nd line	Testimony requesting permission to permit 2nd line
NPCIRP-V3(PUCN Dkt. # 10-02009)	107	Northwest-Amargosa	Testimony justification
NPCIRP-V3(PUCN Dkt. # 10-02009)	107	Harry Allen-Eldorado	Testimony justification
NPCIRP-V3(PUCN Dkt. # 10-02009)	108	LV 230 kV Reactors	Testimony justification
NPCIRP-V3(PUCN Dkt. # 10-02009)	109	Toquop Interconnect	Testimony justification
NPCIRP-V3(PUCN Dkt. # 10-02009)	110	Valley Electric Interconnect	Testimony justification
NPCIRP-V3(PUCN Dkt. # 10-02009)	119	Renewable Resource Limits	Salgo testimony on operational problems with renewable resources
NPCIRP-V3(PUCN Dkt. # 10-02009)	316	IRP Action Plan	action plan
NPCIRP-V3(PUCN Dkt. # 10-02009)	323	Transmission Action Plan	Section of Action Plan specifically on trasmission
NPCIRP-V3(PUCN Dkt. # 10-02009)	326	LV 230 kV Reactors	Locations of reactors discussed
NPCIRP-V3(PUCN Dkt. # 10-02009)	328	Northwest-Harry Allen	Costs and time line
NPCIRP-V3(PUCN Dkt. # 10-02009)	328	Northwest-Amargosa	Costs and time line
NPCIRP-V3(PUCN Dkt. # 10-02009)	329	Harry Allen-Eldorado	Costs and time line
NPCIRP-V3(PUCN Dkt. # 10-02009)	332	Toquop Interconnect	Costs and time line
NPCIRP-V4(PUCN Dkt. # 10-02009)	6	ON Line	Summary paragraph
NPCIRP-V4(PUCN Dkt. # 10-02009)	7	Harry Allen-Eldorado	Summary paragraph
NPCIRP-V4(PUCN Dkt. # 10-02009)	7	Northwest-Amargosa	Summary paragraph
NPCIRP-V4(PUCN Dkt. # 10-02009)	37	IRP Summary-Transmission	Section describing the Transmission plan
NPCIRP-V4(PUCN Dkt. # 10-02009)	37	ON Line	Description, cost estimate, and allocation with GBT
NPCIRP-V4(PUCN Dkt. # 10-02009)	38	LV 230 kV Reactors	Locations and costs of reactors discussed
NPCIRP-V4(PUCN Dkt. # 10-02009)	38	Northwest-Harry Allen	Costs

Notable Transmission Info Referenced from RETAAC Phase 2 Report, NV Energy North and South IRP's, & PUCN Filings

Source Report	PDF Page	Transmission Improvement or Topic	Topic Discussed
NPCIRP-V4(PUCN Dkt. # 10-02009)	38	Northwest-Amargosa	Cost and cash flow
NPCIRP-V4(PUCN Dkt. # 10-02009)	38	Harry Allen-Eldorado	Cost and cash flow
NPCIRP-V4(PUCN Dkt. # 10-02009)	38	Harry Allen-Mead	Cost and cash flow
NPCIRP-V18(PUCN Dkt. # 10-02009)	5	Renewable Resource Limits	Operational problems with renewable resources
NPCIRP-V18(PUCN Dkt. # 10-02009)	6	SPP Export Capability	500-600 MW of Export available in all hours in the North
NPCIRP-V18(PUCN Dkt. # 10-02009)	7	SPP-Geothermal Impacts	Section analyzing geothermal generation impacts
NPCIRP-V18(PUCN Dkt. # 10-02009)	11	SPP-Wind Generation Impacts	Section analyzing variable generation impacts
NPCIRP-V18(PUCN Dkt. # 10-02009)	17	SPP-Solar Generation Impacts	Section analyzing solar generation impacts
NPCIRP-V18(PUCN Dkt. # 10-02009)	20	Geothermal Contracts	Table of Geothermal Contracts
NPCIRP-V18(PUCN Dkt. # 10-02009)	21	SPP-Wind Output Projections	Table of Wind Data
NPCIRP-V18(PUCN Dkt. # 10-02009)	35	ON Line	Study of project capabilities for different designs
NPCIRP-V18(PUCN Dkt. # 10-02009)	95	LV 230 kV Reactors	Detailed supporting study
NPCIRP-V18(PUCN Dkt. # 10-02009)	113	Sunrise	Detailed supporting study
NPCIRP-V18(PUCN Dkt. # 10-02009)	130	Valmy #3	Detailed supporting study
NPCIRP-V18(PUCN Dkt. # 10-02009)	159	ON Line	MOU
PUCN #11-05002	6/33	RTI	All 4 projects total 537 miles of new overhead 345 or 500 kV lines
PUCN #11-05002	6/33	Dixie Valley-Oreana Line	Description - 39 miles of new 345 kV line from Dixie Valley to Oreana & interconnect to existing 345 kV lines
PUCN #11-05002	6/33	Dixie Valley-Oreana Line	Discussion of 52 miles of "following existing route for 52 miles from Oreana to Tracy
PUCN #11-05002	6/33	Ft Sage-Eldorado	Description of 498 miles of 230, 345, or 500 kV lines from Ft Sage-E.Tracy-Ft.Churchill-Harry Allen-Eldorado
PUCN #11-05002	6/33	Open Transmission Planning Process	Description of "Open Season"?

Notable Transmission Info Referenced from RETAAC Phase 2 Report, NV Energy North and South IRP's, & PUCN Filings

Source Report	PDF Page	Transmission Improvement or Topic	Topic Discussed
PUCN #11-05002	8/33	Deviation from IRP Action Plan Requirement	Law requires UEPA requests to be in IRP Action Plans.
PUCN #11-05002	15/33	Line routing Info	Description fo line routes.
PUCN #11-05002	16/33	Electrical Characteristics of Lines	Description of tower types and other characteristics of proposed lines.
PUCN #11-05002	23/33	Map of projects	Map of proposed projects.
PUCN #11-05002	25/33	Map of Energy Zones	Map of Renewable Energy Zones to be served by projects.
PUCN #11-05009	5/12	Open Transmission Planning Process	Details of OTPP

APPENDIX A-2

SUMMARY OF NEIGHBORING STATES RPS

SUMMARY OF NEIGHBORING STATES RENEWABLE ENERGY PORTFOLIO STANDARD (RPS) AND EXPORT OPPORTUNITIES

A Renewable Portfolio Standard (RPS) is a regulation that requires the increased production of energy from renewable energy sources, such as wind, solar, biomass, and geothermal. The RPS mechanism generally places an obligation on electricity supply companies to produce or purchase a specified fraction of their electricity from renewable energy sources. RPS mechanisms are intended to eventually result in competition, efficiency and innovation that will deliver renewable energy at the lowest possible cost, allowing renewable energy to compete with cheaper fossil fuel energy sources.

Each state-adopted RPS has its own requirements and implementation mandates. The following summarizes these nuances.

Western State	Year Compliance Required	RPS Target
Nevada	2025	25%
California	2020	33%
Arizona	2025	15%
Utah	2025	20%
Oregon	2025	25%
New Mexico	2020	20%

The RPS requirements and history of the three key states applicable to this study, Nevada, California and Utah, are detailed as follows:

Nevada

Nevada established a renewable portfolio standard (RPS) as part of its 1997 restructuring legislation. Under the standard, NV Energy (formerly Nevada Power and Sierra Pacific Power) must use eligible renewable energy resources to supply a minimum percentage of the total electricity it sells. In 2001, the state increased the minimum requirement by 2% every two years, culminating in a 15% requirement by 2013. The portfolio requirement has been subsequently revised, most significantly by SB 358 of 2009, which increased the requirement to 25% by 2025. The 2009 amendments also raised the solar carve-out, requiring utilities to meet 6% of their portfolio requirement through solar energy beginning in calendar year 2016. The solar carve-out remains at 5% through the end of calendar year 2015.

AB 3 of 2005 allowed efficiency measures to be used to satisfy a portion of the requirement. To qualify as portfolio energy credits, efficiency measures must be: (1) implemented after January 1, 2005; (2) sited or implemented at a retail customer's location; and (3) partially or fully subsidized by the electric utility. The measure must also reduce the customer's energy demand (as opposed to shifting demand to off-peak hours). The contribution from energy efficiency measures to meet the portfolio standard is capped at one-quarter of the total standard in any particular year. AB1 of 2007 expanded the definition of efficiency resources to include district heating systems powered by geothermal hot water.

The following schedule is currently in effect:

- 6% renewable/efficiency in 2005 and 2006
- 9% renewable/efficiency in 2007 and 2008
- 12% renewable/efficiency in 2009 and 2010
- 15% renewable/efficiency in 2011 and 2012
- 18% renewable/efficiency in 2013 and 2014
- 20% renewable/efficiency in 2015 through 2019
- 22% renewable/efficiency in 2020 through 2024
- 25% renewable/efficiency in 2025 and thereafter

In addition to solar, qualifying renewable energy resources include biomass, geothermal energy, wind, certain hydropower, energy recovery processes*, and waste tires (using microwave reduction).

The Public Utilities Commission of Nevada (PUCN) has established a program to allow energy providers to buy and sell portfolio energy credits (PECs) in order to meet energy portfolio requirements. One PEC represents one kilowatt-hour (kWh) of electricity generated by a portfolio energy system, with the exception of photovoltaics (PV), for which 2.4 PECs are credited per one actual kWh of energy produced. An adder of 0.05 is tacked on to the 2.4 multiplier for PV if the system is deemed by the PUCN to be a customer-maintained distributed generation system; that is, customer-sited PV is eligible for a 2.45 multiplier. In addition, the number of kWh saved by energy efficiency measures is multiplied by 1.05 to determine the number of PECs. For electricity saved during peak periods as a result of efficiency measures, the credit multiplier is increased to 2.0. PECs are valid for a period of four years.

To help facilitate the renewable projects required by the renewable energy portfolio standard, the PUCN established the Temporary Renewable Energy Development (TRED) Program. The TRED Program is meant to insure prompt payment to renewable energy providers in order to encourage completion of renewable energy projects. The TRED Program establishes: (1) a TRED charge, allowing investor-owned utilities to collect revenue from electricity customers to pay for renewable energy separate from other wholesale power purchased by the electric utilities; and (2) an independent TRED trust to receive the proceeds from the TRED charge and remit payment to renewable energy projects that deliver renewable energy to purchasing electric utilities.

Nevada currently has approximately 7,835 MW of renewable energy interconnection requests in the Open Access Transmission Tariff (OATT) queue. It is currently meeting its RPS and has begun to limit Power Purchase Agreements with renewable energy developers. It is for this reason that export development is critical to the ongoing development of renewable resources in the State of Nevada.

California

California's Renewable Portfolio Standard was originally established by legislation enacted in 2002. Subsequent amendments to the law have resulted in a requirement for California's electric utilities to have 33% of their retail sales derived from eligible renewable energy resources in 2020 and all subsequent years. The law established interim targets for the utilities as shown below. By January 1, 2012, the California Public Utilities Commission (CPUC) must establish specific electricity sales targets for electric retail sellers based on the interim targets[1]:

- 20% of retail sales by December 31, 2013
- 25% of retails sales by December 31, 2016

Publicly owned municipal utilities (POUs) are not regulated by the CPUC but are affected by the law nonetheless, and their governing boards are charged with establishing procurement requirements based on the interim goals above.

Technologies eligible for the RPS include photovoltaics; solar thermal electric; wind; certain biomass resources; geothermal electric; certain hydroelectric facilities*; ocean wave, thermal and tidal energy; fuel cells using renewable fuels; landfill gas; and municipal solid waste conversion, not the direct combustion of municipal solid waste.

Legislation (AB 2514) enacted in September 2010 allows for the adoption of requirements for utilities to procure energy storage systems. The legislation instructs the CPUC to open a proceeding by March 1, 2012, to consider the adoption of these requirements which would have to be met by the investor-owned utilities in two phases: by December 31, 2015, and December 31, 2020. The CPUC has broad authority for considering these requirements. The legislation also requires the governing boards of municipal utilities with more than 60,000 customers to consider similar requirements according to the same time schedule.

To meet California's RPS reporting requirements and the renewable energy tracking needs of 14 states and two Canadian provinces in the Western Electricity Coordinating Council (WECC), the Energy Commission and the Western Governors' Association have jointly developed the Western Renewable Energy Generation Information System (WREGIS), which began operation in June 2007. WREGIS tracks renewable energy generation and creates WREGIS certificates for every renewable energy credit (REC) generated, which are used to demonstrate compliance with state RPS policies. One REC represents one megawatt-hour (MWh) of electricity generated from a renewable resource.

The California Public Utilities Commission issued a decision on January 13, 2011, to authorize the use of tradable renewable energy credits (TRECS) for RPS compliance. From the 2010 compliance year through December 31, 2013, the use of TRECS was capped at 25% of a utility's RPS requirement, and the price of a TREC was capped at $50. SBX1-2 of 2011 appears to have put new restrictions on the use of TRECs which the CPUC will implement. According to the law, the use of TREC transactions signed after June 10, 2010 will be capped at 25% for the compliance period ending December 31, 2013, and will shrink to 10% of the requirement by 2017.

All of these rules and established RPS requirements clearly defines California as an aggressive renewable energy state. Such laws will require substantial increases in the generation of electricity from renewable energy resources, or the importation from neighboring states. Implementation of these policies will require extensive improvements to California's electric transmission infrastructure. In April 2007, the State of California implemented the Renewable Energy Transmission Initiative (RETI) project as a statewide planning process to identify the transmission projects needed to accommodate California's renewable energy goals. That report identified Out of State Resources in Nevada that totaled 22,099 MW of renewable available resource energy. This was specifically detailed as Biomass (299 MW); Geothermal (1,459 MW); Solar (18,588MW); and Wind (1,754MW). This summary of available resources excluded geothermal developments that were already under PPA contract with NV Energy since these resources are not directly available to California under contract. Specific to the export of Nevada generated renewable power, the issue still remains as to what will be allowed into California from non-California based generation.

Utah

On June 8th, 2010, the Governor of Utah enacted the "Energy Initiates and Imperatives: Utah's 10-Year Strategic Energy Plan. As with many western states, the plan included renewable energy development and export exploration. The difference between Utah and many of the other western states is that the primary reason electric rates in Utah are both low and stable is because the vast majority of electricity that is fueled by coal. Utah has abundant coal supplies. Coal mining, coal transportation and coal-fired power plants in Utah create tens of thousands of jobs, many of them in rural Utah where job opportunities are often limited. These coal-based industries and communities contribute greatly to the State's tax revenue base. Oil and gas taxes account for more than $70 million in tax revenue, property taxes from the energy industry are in excess of $100 million annually and sales and use taxes are estimated to be $63 million a year. Utah is now faced with the issue of more expensive renewable energy development, or continued coal production. In addition, California, one of the main markets historically for coal based power is turned away from coal and embracing the renewable energy demand. In response, Utah enacted *The Energy Resource and Carbon Emission Reduction Initiative* (S.B. 202) in March 2008. While this law contains some provisions similar to those found in renewable portfolio standards (RPSs) adopted by other states, certain other provisions in S.B. 202 indicate that this law is more accurately described as a renewable portfolio *goal* (RPG). Specifically, the law requires that utilities only need to pursue renewable energy to the extent that it is "cost-effective" to do so. The guidelines for determining the cost-effectiveness of acquiring an energy source include an assessment of whether acquisition of the resource will result in the delivery of electricity at the lowest reasonable cost, as well as an assessment of long-term and short-term impacts, risks, reliability, financial impacts on the affected utility, and other factors determined by the Utah Public Service Commission (PSC).

Under S.B. 202 -- to the extent that it is cost-effective to do so -- investor-owned utilities, municipal utilities and cooperative utilities must use eligible renewable energy to account for 20% of their 2025 adjusted retail electric sales. Adjusted retail sales include the total kilowatt-hours (kWh) of retail electric sales reduced by the kWh attributable to nuclear power plants, demand-side management measures, and fossil fuel power plants that sequester their carbon emissions. For example, if a utility has electric sales of 100 million megawatt-hours (MWh) in 2025, and 10 million MWh was produced at a nuclear plant, the utility would need to produce 20% of 90 million MWh from renewable energy sources to be in compliance.

While RPSs adopted by most states include interim targets that increase over time, Utah's goal has no interim targets. The first compliance year is 2025 (although utilities must file progress reports on January 1 of 2010, 2015, 2020 and 2024). Progress reports must indicate the actual and projected amount of qualifying electricity the utility has acquired the source of the electricity, an estimate of the cost for the utility to achieve their target, and any recommendations for a legislative or program change.

APPENDIX A-3

RETAAC PHASE II REPORT REFERENCE & MAPS

Governor Jim Gibbons'

Nevada Renewable Energy Transmission

Access Advisory Committee Phase II

Volume I Executive Summary and Report

July 1, 2009

Volume I contains the Committee's Executive Summary and Report
Volume II contains the presentations made to the Committee
Both Volumes, and all the Committee meeting minutes and agendas, can be found on the Committee's web site
http://www.retaac.org/

Table of Contents

Introduction

Nevada is blessed with some of the richest renewable resources in the world. We are also fortunate to have the full spectrum of renewable resources including geothermal, wind, solar and even biomass. Very few other regions in the world are so lucky. There are enough megawatts of renewable resources in Nevada to easily fulfill our renewable electricity needs and the needs of our surrounding states.

Developing these resources will bring billions of dollars in investment capital to the state. It will diversity our economy, create thousands of high-paying jobs, help protect our pristine high desert environment and reduce our water use. However, without the transmission necessary to get the electricity generated by these projects to markets none of these resources will be tapped.

Nevada's Governor Jim Gibbons recognized the critical role transmission plays in the development and protection of our state's resources. To help identify and remove the barriers to transmission he created the Renewable Energy Transmission Access Advisory Committee (RETAAC). This report contains the findings and recommendations of that committee. The members of the Committee thank the Governor for the opportunity to serve our great state and look forward to working with government and industry to build the transmission lines that will unleash the economic power represented by our states bountiful renewable resources.

Executive Summary

Background

On June 12, 2008, Governor Jim Gibbons signed an Executive Order creating the second phase of RETAAC to further the committee's initial efforts as described in the RETAAC Phase I Report dated December 31, 2007. The committee was charged with: (i) determining power potential for the renewable energy zones designated by the first phase; (ii) the review of environmental, land use and permitting constraints; (iii) the identification of potential construction corridors that could avoid these constraints, and (iv) the review of potential revenue needs for construction, among other duties.

In establishing the Phase II Committee, the governor stated that: "....,the first RETAAC committee made a recommendation to initiate Phase II to define the environmental and physical feasibility issues, costs and potential financing mechanisms associated with the recommended 14 transmission routes. This [Phase II] committee will implement this recommendation."

The nineteen (19) Phase II committee members were appointed by the Governor under the chairmanship of Daniel (Dan) Schochet. They included representation from key interest groups who were given the task of working together to recommend the mechanisms finance and construct the additional transmission lines to access the state's vast renewable energy resources for the benefit of the citizens of Nevada.

To implement the objectives of RETAAC Phase II, the committee created Study Groups with the following assignments:

1. *Environmental and Land Use Constraints:* The Environmental and Land Use Constraints Study Group consisted of members of state and federal agencies with interest and oversight of these issues, along with volunteers from industry and advocacy groups. The study group was tasked with providing information on these issues which could be used in prioritizing and analyzing the feasibility of constructing the proposed transmission lines to the renewable energy zones. ***After evaluating available secondary data collected for this project and consulting with representatives from land management agencies, no fatal flaws were indentified for the proposed interconnections.***

2. *Renewable Energy Zone Prioritizations:* The Renewable Energy Zone Prioritization Study Group was tasked with: a) developing a method for prioritizing the zones defined in RETAAC Phase I, and the transmission links that serve these zones; and b) presenting these recommendations to RETAAC Phase II. The methodology developed resulted in a matrix which employed four evaluation criteria: (i) renewable energy potential; (ii) cost of transmission construction; (iii) transmission environmental impact; and (iv) other system benefits from

transmission. ***This matrix served as the basis for the analysis by the Economic Feasibility Study Group.***

3. *Economic Feasibility:* The Economic Feasibility Study Group was tasked with answering the critical questions including: (i) how much does a transmission line developer need to charge for the use of the transmission line to recover the construction costs and operating and maintenance expenses including a sufficient return on the investment; (ii) how much are the resource developers willing to pay for the use of the transmission line; and (iii) are the renewable resource providers still competitive after recovering the cost of delivering their energy to load centers. ***The results of this analysis indicates that certain transmission lines could charge economically acceptable fees for the use of the transmission lines and that these fees could recover the costs, if the transmission line usage were fully subscribed.***

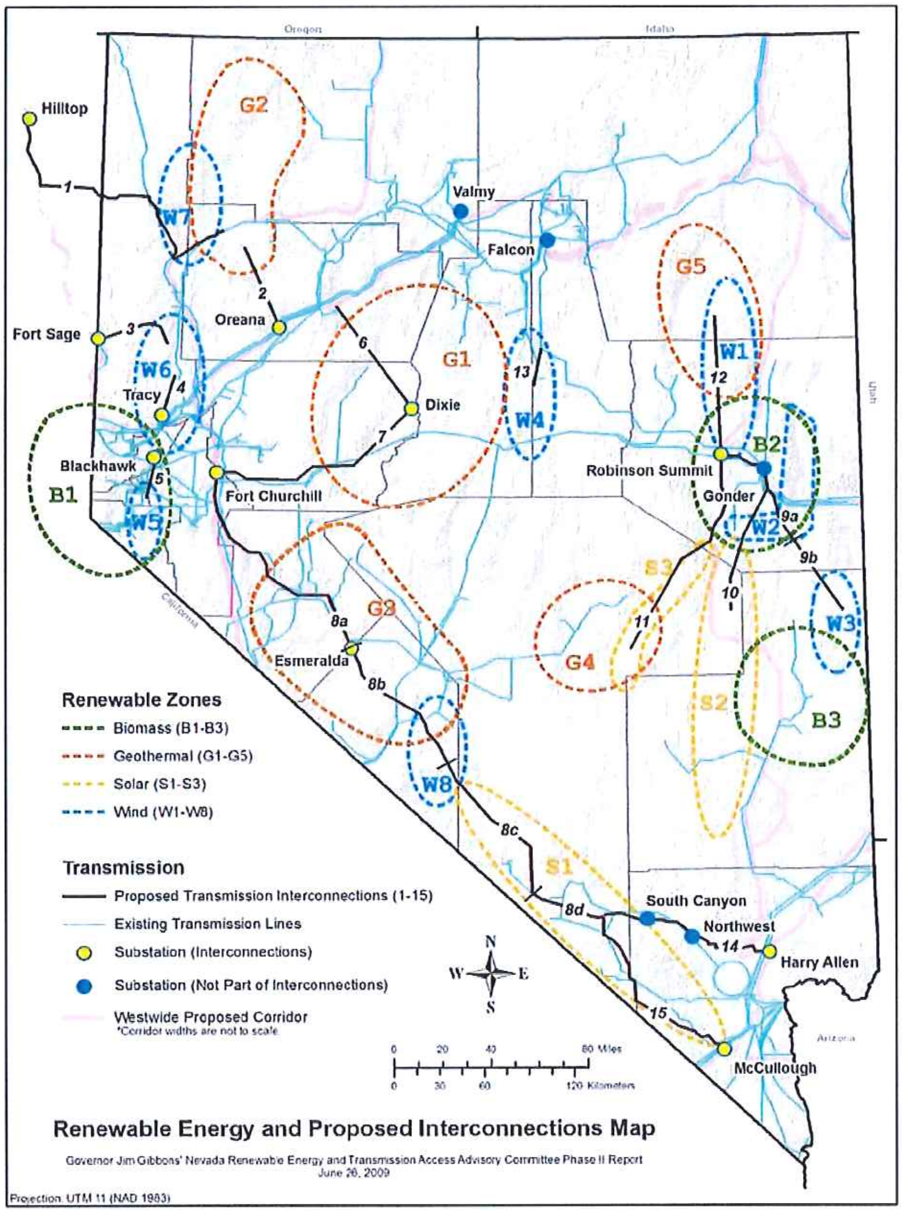
4. *Transmission for Export:* The Export Study Group was tasked with identifying existing transmission facilities and proposed transmission projects that could be used to export energy from Nevada's renewable resources to adjacent states. This task assumed that such export would in essence be in addition to the needs of Nevada load serving utilities and would also result in economic benefit to the citizens of the state. ***The results indicate that a significant market exists in California, Arizona and elsewhere for Nevada's renewable energy and that the transmission paths are feasible.***

5. Feasibility Criteria: The Feasibility Criteria Study Group, which consisted of representatives of: (i) publically owned and investor owned utilities; (ii) representatives of the Public Utility Commission of Nevada: (iii) the committee chairman; and (iv) the Governor's Energy Advisor, was tasked with drafting the recommendations for the RETAAC approval.

Findings

The chapters in this report are the work product of their respective Study Groups. These highly detailed, technical work products contain findings and recommendations which are generalized and summarized here.

The first principal finding is a map showing what are believed to be the state's most economically viable renewable energy zones and the transmission necessary to access the electricity believed to be contained within those zones.

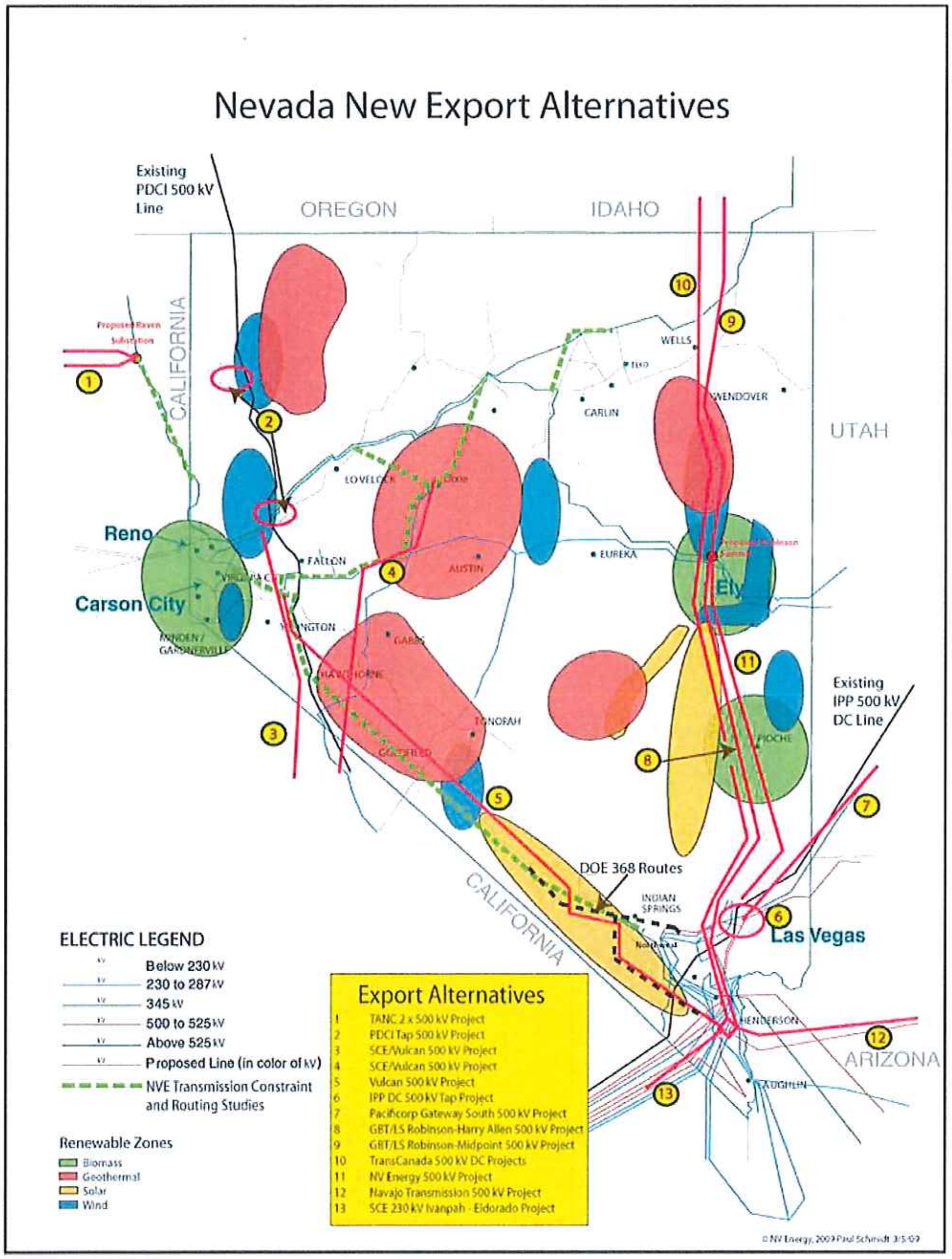


Renewable Energy and Proposed Interconnections Map

Governor Jim Gibbons' Nevada Renewable Energy and Transmission Access Advisory Committee Phase II Report
June 26, 2009

Projection: UTM 11 (NAD 1983)

New transmission lines necessary to export the electricity contained in the zones were also identified.



The final principal finding ranks the economic feasibility of the transmission needed to access each prioritized renewable energy zone.

ECONOMIC FEASIBILITY AND RENEWABLE ENERGY ZONE PRIORITY (REZP) RANKINGS

Transmission Segment	Zone	Terminals	Construction Cost ($million)	Economic Feasibility Ranking	REZP Ranking
8D+14	S-1	Harry Allen	$358.0	1	1
9A	W-2	Robinson	$118.1	2	1
2	G-2	Oreana	$26.8	3	4
9A+9B	W-3	Robinson	$176.9	4	3
8D+15	S-1	McCullough	$417.3	5	4
5	W-5	Blackhawk	$18.8	6	7
10	S-2	Robinson	$221.7	7	7
8A	G-3	Ft. Churchill/Blackhawk	$163.3	7	10
12	G-5	Robinson	$81.9	9	11
4	W-6	Tracy	$47.0	10	7
7	G-1	Ft. Churchill/Blackhawk	$167.5	11	4
13	W-4	Frontier	$55.2	12	16
3	W-6	Ft. Sage	$58.9	13	11
12	W-1	Robinson	$81.9	14	11
11	G-4	Robinson	$112.5	15	16
8A+8B	W-8	Ft. Churchill/Blackhawk	$216.0	16	20
6	G-1	Oreana	$120.9	16	11
8A+8B+8C	S-1	Ft. Churchill/Blackhawk	$127.9	18	15
1	G-2	Hilltop	$82.4	18	16
8C+8D+14	W-8	Harry Allen	$131.5	20	16
8C+8D+15	W-8	McCullough	$131.5	21	20

Recommendations

To finance and construct the additional transmission lines as recommended and prioritized by the Study Groups, RETAAC Phase II makes the following recommendations:

1. Renewable energy access to the Nevada transmission grid is facilitated by providing the state with a robust and reliable statewide transmission system, which serves all load customers from all available and potential generation sources. This is the surest way to promote the access to the grid by renewable energy resources.

2. The tax exempt bond financing mechanism, under consideration by the Governor's office, and other such mechanisms, should be encouraged to develop a financing program which can substantially reduce the cost of constructing new transmission lines and facilities and thus enhance their economic feasibility. However; regardless what the driving technical, regulatory, or siting issues are, establishing a mechanism to repay the investment is critical before any plan can move forward with the construction of these transmission lines and associated facilities.

3. The Public Utilities Commission of Nevada, as the primary utility regulatory agency in the state, to the extent possible, should employ flexibility so as to encourage new renewable transmission construction for in state use and export to adjacent states by:

    - Considering the impacts of local and statewide economic development as an element in the planning and approval of new transmission,

    - Encouraging flexibility in financing of new transmission construction; and

    - Considering the requirements of the state's utilities to meet Nevada's Portfolio Standard mandate when evaluating proposed new transmission construction projects.

4. New renewable transmission should be designed and constructed by entities that have the financial capacity, the expertise, and the understanding of local and regional Nevada issues as well as the experience to design, permit, construct and integrate these facilities into the existing grid.

5. The state_should create a functional entity, which will serve as a "one stop shop" to assist potential transmission providers in working with local, state, federal agencies and tribal lands in overcoming the permitting and siting constraints and barriers so as to expedite the construction of the required new transmission lines and facilities.

6. The state of Nevada should work with new and existing state and federal statutes, as well as seek additional resources to further the recommendations of this report.

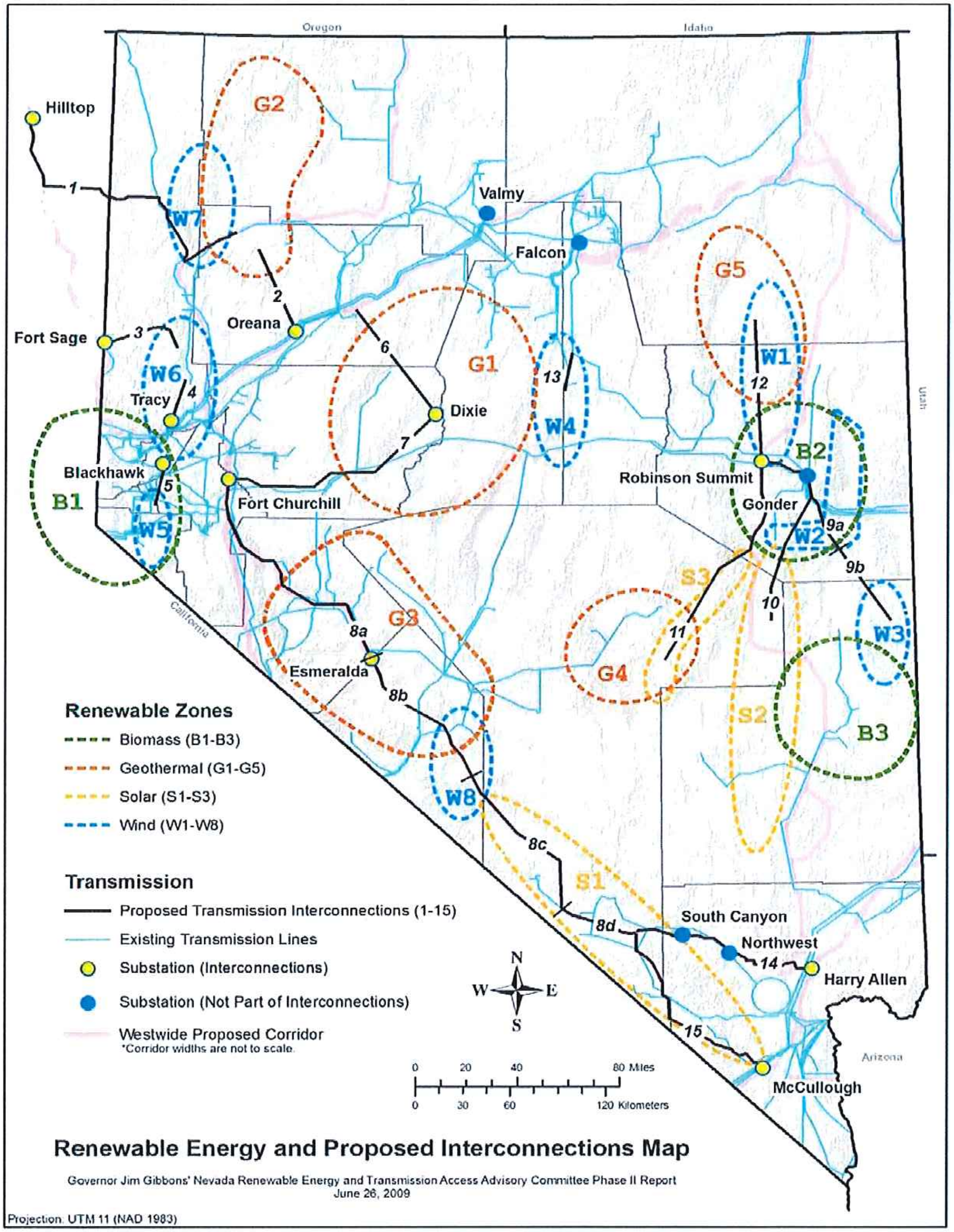

Oregon
Idaho
Utah
Arizona
California
Hilltop
Valmy
Falcon
Oreana
Fort Sage
Tracy
Dixie
Blackhawk
Fort Churchill
Robinson Summit
Gonder
Esmeralda
South Canyon
Northwest
Harry Allen
McCullough
G1
G2
G3
G4
G5
W1
W2
W3
W4
W5
W6
W7
W8
B1
B2
B3
S1
S2
S3
1
2
3
4
5
6
7
8a
8b
8c
8d
9a
9b
10
11
12
13
14
15
Renewable Zones
Biomass (B1-B3)
Geothermal (G1-G5)
Solar (S1-S3)
Wind (W1-W8)
Transmission
Proposed Transmission Interconnections (1-15)
Existing Transmission Lines
Substation (Interconnections)
Substation (Not Part of Interconnections)
Westwide Proposed Corridor
*Corridor widths are not to scale.
N
W
E
S
0 20 40 80 Miles
0 30 60 120 Kilometers
Renewable Energy and Proposed Interconnections Map
Governor Jim Gibbons' Nevada Renewable Energy and Transmission Access Advisory Committee Phase II Report
June 26, 2009
Projection: UTM 11 (NAD 1983)

FIGURE 2

POTENTIAL PROJECT PHASES
and
RETAAC RENEWABLE ENERGY ZONES

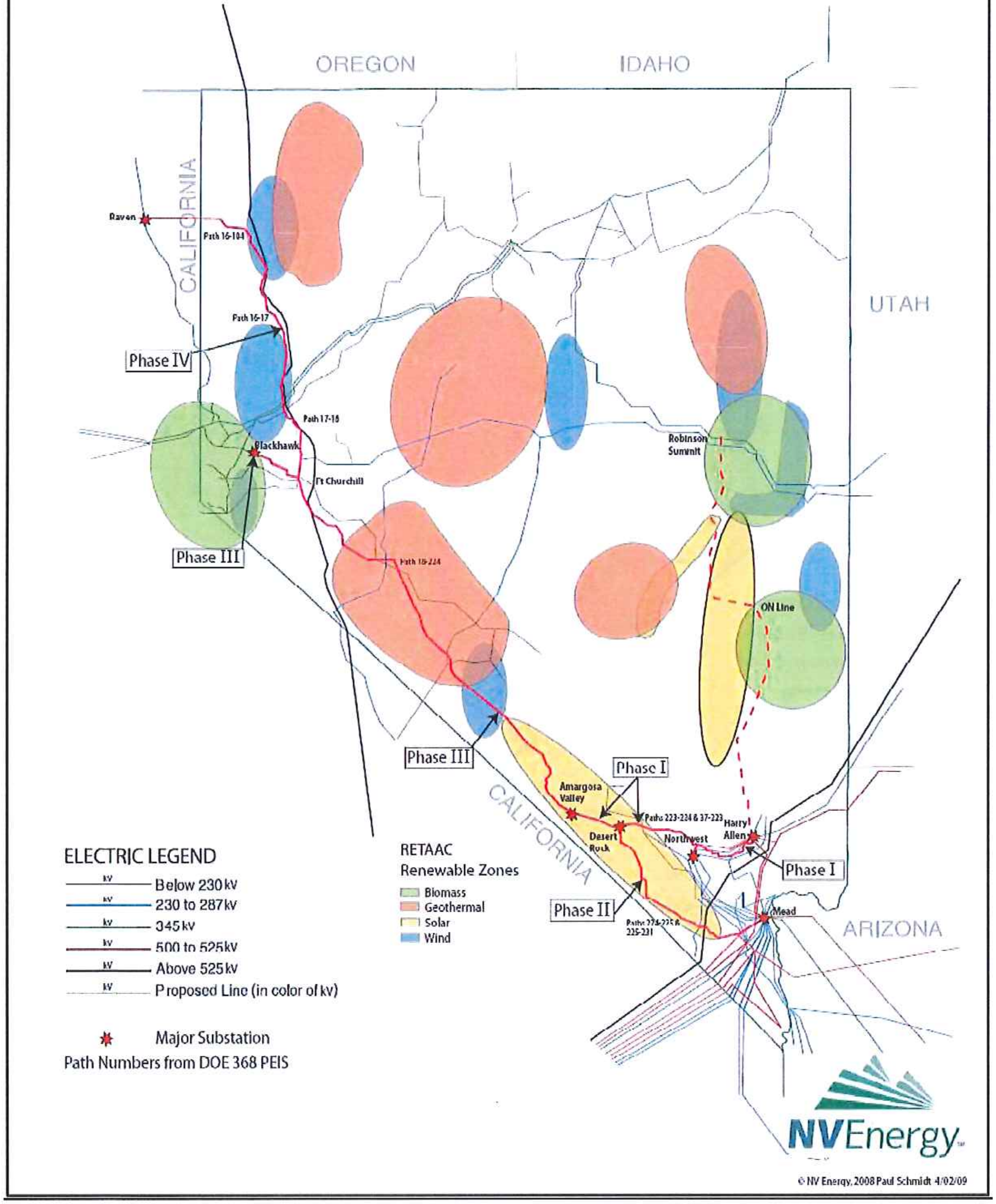


FIGURE 2

APPENDIX A-4

SUMMARY OF ASSEMBLY BILL NO. 387

ASSEMBLY BILL NO. 387 – MARCH 16, 2009

ENERGY

A.B. 387 (Chapter 246)

Assembly Bill 387 revises provisions relating to the triennial resource plans of electric utilities. It directs the Public Utilities Commission of Nevada (PUCN) to designate renewable energy zones where resources are sufficient to develop generating capacity and where transmission constrains the delivery of electricity to customers. The bill also directs the PUCN to require an electric utility to include a plan for construction of transmission facilities to serve the zones in its resource plan.

In its review of an electric utility's resource plan, A.B. 387 requires the PUCN to consider the level of financial commitment from developers of renewable energy projects in each zone. The PUCN may accept a transmission plan for a given zone if the construction of transmission facilities would assist the utility in meeting the renewable portfolio standard.

Assembly Bill 387 also revises the renewable portfolio standard (RPS). The bill:

- Requires a provider of electric service to generate, acquire, or save not less than 25 percent of electricity sold in 2025 and each year thereafter from renewable energy systems or efficiency measures;

- Requires at least 6 percent of the RPS requirement in 2016 and each year thereafter to be generated or acquired from solar renewable energy systems;

- Amends the definition of "renewable energy system" to include systems that transmit electricity via power lines connected to, but not owned, operated, or controlled by a provider; and

- Establishes a separate, parallel RPS requirement for a provider of new electric resources effective on the date on which the PUCN issues an order approving the application.

This measure is effective on July 1, 2009.

Assembly Bill No. 387–Assemblymen Conklin, Kirkpatrick, Leslie, Buckley, Oceguera; and Bobzien

CHAPTER..........

AN ACT relating to public utilities; requiring public utilities to submit certain information regarding renewable energy to the Public Utilities Commission of Nevada; authorizing the Commission to approve construction or expansion of transmission facilities based on an expectation of future renewable energy development; revising provisions requiring certain providers of electric service to comply with a portfolio standard for renewable energy; and providing other matters properly relating thereto.

Legislative Counsel's Digest:

Section 6 of this bill requires a utility to submit with its plan to increase its supply of electricity or decrease the demands made by its customers a description of specific geographic zones where renewable energy could be used to generate electricity but transmission facilities are inadequate to deliver such electricity to customers.

Section 7 of this bill requires the Public Utilities Commission of Nevada to consider the level of financial commitment from developers of renewable energy projects when evaluating a plan submitted pursuant to NRS 704.741.

Section 8 of this bill allows the Commission to accept a transmission plan if it would help the utility to meet the portfolio standard defined in NRS 704.7805.

Section 4.3 of this bill requires the Commission to report to the Director of the Legislative Counsel Bureau by February 15 of each odd-numbered year concerning any transmission plan proposed, accepted or made known to the Commission since the last report.

Section 9 of this bill revises the amount of electricity that a provider must generate, acquire or save to satisfy the portfolio standard from 2025 onward. **Section 9** also revises the amount of electricity that must be generated or acquired from solar energy renewable systems to satisfy the portfolio standard from 2015 onward. Additionally, **section 9** exempts providers of new electric resources from the portfolio standard that is applicable to other providers of electric service.

Section 4.7 of this bill provides that the portfolio standard for electricity sold by providers of new electric resources is the portfolio standard set forth in NRS 704.7821 which is effective on the date on which the Commission issues an order approving an application or request submitted by the provider of new electric resources.

Section 11 of this bill requires the plan described in **section 6** to be filed not later than January 1, 2011. **Section 12** of this bill requires the Commission to adopt regulations designating renewable energy zones not later than January 1, 2010.

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

Section 1. NRS 701B.290 is hereby amended to read as follows:

701B.290 1. After a participant installs a solar energy system included in the Solar Program, the Commission shall issue portfolio energy credits for use within the system of portfolio energy credits adopted by the Commission pursuant to NRS 704.7821 ~~[.]~~ ***and section 4.7 of this act.***

2. The Commission shall designate the portfolio energy credits issued pursuant to this section as portfolio energy credits generated, acquired or saved from solar renewable energy systems for the purposes of the portfolio standard.

3. All portfolio energy credits issued for a solar energy system installed pursuant to the Solar Program must be assigned to and become the property of the utility administering the Program.

Sec. 2. NRS 701B.640 is hereby amended to read as follows:

701B.640 1. After a participant installs a wind energy system included in the Wind Demonstration Program, the Commission shall issue portfolio energy credits for use within the system of portfolio energy credits adopted by the Commission pursuant to NRS 704.7821 ***and section 4.7 of this act*** equal to the actual or estimated kilowatt-hour production of the wind energy system.

2. All portfolio energy credits issued for a wind energy system installed pursuant to the Wind Demonstration Program must be assigned to and become the property of the utility administering the Program.

Sec. 3. NRS 701B.870 is hereby amended to read as follows:

701B.870 1. After a participant installs a waterpower energy system included in the Waterpower Demonstration Program, the Commission shall issue portfolio energy credits for use within the system of portfolio energy credits adopted by the Commission pursuant to NRS 704.7821 ***and section 4.7 of this act*** equal to the actual or estimated kilowatt-hour production of the waterpower energy system of the participant.

2. All portfolio energy credits issued for a waterpower energy system installed pursuant to the Waterpower Demonstration Program are assigned to and become the property of the utility administering the Program.

Sec. 4. Chapter 704 of NRS is hereby amended by adding thereto the provisions set forth as sections 4.3 and 4.7 of this act.

Sec. 4.3. ***On or before February 15 of each odd-numbered year, the Commission shall review, approve and submit to the***

Director of the Legislative Counsel Bureau for transmittal to the next regular session of the Legislature a written report compiling all information about any transmission plan proposed by, adopted by or made known to the Commission since the last report.

Sec. 4.7. ***1. If the Commission issues an order approving an application that is filed pursuant to NRS 704B.310 or a request that is filed pursuant to NRS 704B.325 regarding a provider of new electric resources and an eligible customer, the Commission must establish in the order a portfolio standard applicable to the electricity sold by the provider of new electric resources to the eligible customer in accordance with the order. The portfolio standard must require the provider of new electric resources to generate, acquire or save electricity from portfolio energy systems or efficiency measures in the amounts described in the portfolio standard set forth in NRS 704.7821 which is effective on the date on which the order approving the application or request is approved.***

2. Of the total amount of electricity that a provider of new electric resources is required to generate, acquire or save from portfolio energy systems or efficiency measures during each calendar year, not more than 25 percent of that amount may be based on energy efficiency measures.

3. If, for the benefit of one or more eligible customers, the eligible customer of a provider of new electric resources has paid for or directly reimbursed, in whole or in part, the costs of the acquisition or installation of a solar energy system which qualifies as a renewable energy system and which reduces the consumption of electricity, the total reduction in the consumption of electricity during each calendar year that results from the solar energy system shall be deemed to be electricity that the provider of new electric resources generated or acquired from a renewable energy system for the purposes of complying with its portfolio standard.

4. As used in this section:

(a) "Eligible customer" has the meaning ascribed to it in NRS 704B.080.

(b) "Provider of new electric resources" has the meaning ascribed to it in NRS 704B.130.

Sec. 5. NRS 704.736 is hereby amended to read as follows:

704.736 The application of NRS 704.736 to 704.751, inclusive, ***and section 4.3 of this act*** is limited to any public utility in the business of supplying electricity which has an annual operating revenue in this state of $2,500,000 or more.

Sec. 6. NRS 704.741 is hereby amended to read as follows:

704.741 1. A utility which supplies electricity in this State shall, on or before July 1 of every third year, in the manner specified by the Commission, submit a plan to increase its supply of electricity or decrease the demands made on its system by its customers to the Commission.

2. The Commission shall, by regulation ~~[, prescribe]~~ ***:***

(a) Prescribe the contents of such a plan including, but not limited to, the methods or formulas which are used by the utility to:

~~[(a)]~~ *(1)* Forecast the future demands; and

~~[(b)]~~ *(2)* Determine the best combination of sources of supply to meet the demands or the best method to reduce them ~~[.]~~ ***; and***

(b) Designate renewable energy zones and revise the designated renewable energy zones as the Commission deems necessary.

3. The Commission shall require the utility to include in its plan an energy efficiency program for residential customers which reduces the consumption of electricity or any fossil fuel. The energy efficiency program must include, without limitation, the use of new solar thermal energy sources.

4. The Commission shall require the utility to include in its plan a plan for construction or expansion of transmission facilities to serve renewable energy zones and to facilitate the utility in meeting the portfolio standard established by NRS 704.7821.

5. As used in this section, "renewable energy zones" means specific geographic zones where renewable energy resources are sufficient to develop generation capacity and where transmission constrains the delivery of electricity from those resources to customers.

Sec. 7. NRS 704.746 is hereby amended to read as follows:

704.746 1. After a utility has filed its plan pursuant to NRS 704.741, the Commission shall convene a public hearing on the adequacy of the plan.

2. At the hearing any interested person may make comments to the Commission regarding the contents and adequacy of the plan.

3. After the hearing, the Commission shall determine whether:

(a) The forecast requirements of the utility are based on substantially accurate data and an adequate method of forecasting.

(b) The plan identifies and takes into account any present and projected reductions in the demand for energy that may result from measures to improve energy efficiency in the industrial, commercial, residential and energy producing sectors of the area being served.

(c) The plan adequately demonstrates the economic, environmental and other benefits to this State and to the customers of the utility, associated with the following possible measures and sources of supply:

(1) Improvements in energy efficiency;

(2) Pooling of power;

(3) Purchases of power from neighboring states or countries;

(4) Facilities that operate on solar or geothermal energy or wind;

(5) Facilities that operate on the principle of cogeneration or hydrogeneration; ~~[and]~~

(6) Other generation facilities ~~[.]~~ ***; and***

(7) Other transmission facilities.

4. The Commission may give preference to the measures and sources of supply set forth in paragraph (c) of subsection 3 that:

(a) Provide the greatest economic and environmental benefits to the State;

(b) Are consistent with the provisions of this section; and

(c) Provide levels of service that are adequate and reliable.

5. The Commission shall:

(a) Adopt regulations which determine the level of preference to be given to those measures and sources of supply; and

(b) Consider the value to the public of using water efficiently when it is determining those preferences.

6. The Commission shall:

(a) Consider the level of financial commitment from developers of renewable energy projects in each renewable energy zone, as designated pursuant to subsection 2 of NRS 704.741; and

(b) Adopt regulations establishing a process for considering such commitments including, without limitation, contracts for the sale of energy, leases of land and mineral rights, cash deposits and letters of credit.

Sec. 8. NRS 704.751 is hereby amended to read as follows:

704.751 1. After a utility has filed the plan required pursuant to NRS 704.741, the Commission shall issue an order accepting the plan as filed or specifying any portions of the plan it deems to be inadequate:

(a) Within 135 days for any portion of the plan relating to the energy supply plan for the utility for the 3 years covered by the plan; and

(b) Within 180 days for all portions of the plan not described in paragraph (a).
2. If a utility files an amendment to a plan, the Commission shall issue an order accepting the amendment as filed or specifying any portions of the amendment it deems to be inadequate within 135 days of the filing of the amendment.
3. All prudent and reasonable expenditures made to develop the utility's plan, including environmental, engineering and other studies, must be recovered from the rates charged to the utility's customers.
4. The Commission may accept a transmission plan submitted pursuant to subsection 4 of NRS 704.741 for a renewable energy zone if the Commission determines that the construction or expansion of transmission facilities would facilitate the utility meeting the portfolio standard, as defined in NRS 704.7805.
5. The Commission shall adopt regulations establishing the criteria for determining the adequacy of a transmission plan submitted pursuant to subsection 4 of NRS 704.741.
Sec. 8.2. NRS 704.775 is hereby amended to read as follows:
704.775 1. The billing period for net metering must be a monthly period.
2. The net energy measurement must be calculated in the following manner:
(a) The utility shall measure, in kilowatt-hours, the net electricity produced or consumed during the billing period, in accordance with normal metering practices.
(b) If the electricity supplied by the utility exceeds the electricity generated by the customer-generator which is fed back to the utility during the billing period, the customer-generator must be billed for the net electricity supplied by the utility.
(c) If the electricity generated by the customer-generator which is fed back to the utility exceeds the electricity supplied by the utility during the billing period:
(1) Neither the utility nor the customer-generator is entitled to compensation for the electricity provided to the other during the billing period.
(2) The excess electricity which is fed back to the utility during the billing period is carried forward to the next billing period as an addition to the kilowatt-hours generated by the customer-generator in that billing period. If the customer-generator is billed for electricity pursuant to a time-of-use rate schedule, the excess electricity carried forward must be added to the same time-of-use period as the time-of-use period in which it was generated unless the

subsequent billing period lacks a corresponding time-of-use period. In that case, the excess electricity carried forward must be apportioned evenly among the available time-of-use periods.

(3) Excess electricity may be carried forward to subsequent billing periods indefinitely, but a customer-generator is not entitled to receive compensation for any excess electricity that remains if:

(I) The net metering system ceases to operate or is disconnected from the utility's transmission and distribution facilities;

(II) The customer-generator ceases to be a customer of the utility at the premises served by the net metering system; or

(III) The customer-generator transfers the net metering system to another person.

(4) The value of the excess electricity must not be used to reduce any other fee or charge imposed by the utility.

3. If the cost of purchasing and installing a net metering system was paid for:

(a) In whole or in part by a utility, the electricity generated by the net metering system shall be deemed to be electricity that the utility generated or acquired from a renewable energy system for the purposes of complying with its portfolio standard pursuant to NRS 704.7801 to 704.7828, inclusive ~~[.]~~ ***, and section 4.7 of this act.***

(b) Entirely by a customer-generator, the Commission shall issue to the customer-generator portfolio energy credits for use within the system of portfolio energy credits adopted by the Commission pursuant to NRS 704.7821 ***and section 4.7 of this act*** equal to the electricity generated by the net metering system.

4. A bill for electrical service is due at the time established pursuant to the terms of the contract between the utility and the customer-generator.

Sec. 8.4. NRS 704.7801 is hereby amended to read as follows:

704.7801 As used in NRS 704.7801 to 704.7828, inclusive, ***and section 4.7 of this act,*** unless the context otherwise requires, the words and terms defined in NRS 704.7802 to 704.7819, inclusive, have the meanings ascribed to them in those sections.

Sec. 8.6. NRS 704.7805 is hereby amended to read as follows:

704.7805 "Portfolio standard" means the amount of electricity that a provider must generate, acquire or save from portfolio energy systems or efficiency measures, as established by the Commission pursuant to NRS 704.7821 ~~[.]~~ ***and section 4.7 of this act.***

Sec. 8.8. NRS 704.7815 is hereby amended to read as follows:

704.7815 "Renewable energy system" means:

1. A facility or energy system that ~~[:]~~

~~[(a) Uses]~~ ***uses*** renewable energy or energy from a qualified energy recovery process to generate electricity ~~[;]~~ and ***:***

(a) Uses the electricity that it generates from renewable energy or energy from a qualified recovery process in this State; or

(b) Transmits or distributes the electricity that it generates from renewable energy or energy from a qualified energy recovery process ~~[via:~~

~~(1) A power line which is dedicated to the transmission or distribution of electricity generated from renewable energy or energy from a qualified energy recovery process and which is connected to a facility or system owned, operated or controlled by a provider of electric service; or~~

~~(2) A power line which is shared with not more than one facility or energy system generating electricity from nonrenewable energy and which is connected to a facility or system owned, operated or controlled by a provider of electric service.]~~ ***to a provider of electric service for delivery into and use in this State.***

2. A solar energy system that reduces the consumption of electricity or any fossil fuel.

3. A net metering system used by a customer-generator pursuant to NRS 704.766 to 704.775, inclusive.

Sec. 9. NRS 704.7821 is hereby amended to read as follows:

704.7821 1. For each provider of electric service, the Commission shall establish a portfolio standard. The portfolio standard must require each provider to generate, acquire or save electricity from portfolio energy systems or efficiency measures in an amount that is:

(a) For calendar years 2005 and 2006, not less than 6 percent of the total amount of electricity sold by the provider to its retail customers in this State during that calendar year.

(b) For calendar years 2007 and 2008, not less than 9 percent of the total amount of electricity sold by the provider to its retail customers in this State during that calendar year.

(c) For calendar years 2009 and 2010, not less than 12 percent of the total amount of electricity sold by the provider to its retail customers in this State during that calendar year.

(d) For calendar years 2011 and 2012, not less than 15 percent of the total amount of electricity sold by the provider to its retail customers in this State during that calendar year.

(e) For calendar years 2013 and 2014, not less than 18 percent of the total amount of electricity sold by the provider to its retail customers in this State during that calendar year.

(f) For calendar ~~[year]~~ ***years*** 2015 ~~[and for each calendar year thereafter,]~~ ***through 2019, inclusive,*** not less than 20 percent of the total amount of electricity sold by the provider to its retail customers in this State during that calendar year.

(g) For calendar years 2020 through 2024, inclusive, not less than 22 percent of the total amount of electricity sold by the provider to its retail customers in this State during that calendar year.

(h) For calendar year 2025 and for each calendar year thereafter, not less than 25 percent of the total amount of electricity sold by the provider to its retail customers in this State during that calendar year.

2. ~~[Except as otherwise provided in subsection 3, in]~~ ***In*** addition to the requirements set forth in subsection 1, the portfolio standard for each provider must require that:

(a) Of the total amount of electricity that the provider is required to generate, acquire or save from portfolio energy systems or efficiency measures during each calendar year, not less than ***:***

(1) For calendar years 2009 through 2015, inclusive, 5 percent of that amount must be generated or acquired from solar renewable energy systems.

(2) For calendar year 2016 and for each calendar year thereafter, 6 percent of that amount must be generated or acquired from solar renewable energy systems.

(b) Of the total amount of electricity that the provider is required to generate, acquire or save from portfolio energy systems or efficiency measures during each calendar year, not more than 25 percent of that amount may be based on energy efficiency measures. If the provider intends to use energy efficiency measures to comply with its portfolio standard during any calendar year, of the total amount of electricity saved from energy efficiency measures for which the provider seeks to obtain portfolio energy credits pursuant to this paragraph, at least 50 percent of that amount must be saved from energy efficiency measures installed at service locations of residential customers of the provider, unless a different percentage is approved by the Commission.

(c) If the provider acquires or saves electricity from a portfolio energy system or efficiency measure pursuant to a renewable energy contract or energy efficiency contract with another party:

(1) The term of the contract must be not less than 10 years, unless the other party agrees to a contract with a shorter term; and

(2) The terms and conditions of the contract must be just and reasonable, as determined by the Commission. If the provider is a

utility provider and the Commission approves the terms and conditions of the contract between the utility provider and the other party, the contract and its terms and conditions shall be deemed to be a prudent investment and the utility provider may recover all just and reasonable costs associated with the contract.

3. ~~[The provisions of paragraphs (b) and (c) of subsection 2 do not apply to a provider of new electric resources pursuant to chapter 704B of NRS with respect to its use of an energy efficiency measure that is financed by a customer, or which is a geothermal energy system for the provision of heated water to one or more customers and which reduces the consumption of electricity or any fossil fuel, except that, of the total amount of electricity that the provider is required to generate, acquire or save from portfolio energy systems or efficiency measures during each calendar year, not more than 25 percent of that amount may be based on energy efficiency measures.~~

~~4.]~~ If, for the benefit of one or more retail customers in this State, the provider ~~[, or the customer of a provider of new electric resources pursuant to chapter 704B of NRS,]~~ has paid for or directly reimbursed, in whole or in part, the costs of the acquisition or installation of a solar energy system which qualifies as a renewable energy system and which reduces the consumption of electricity, the total reduction in the consumption of electricity during each calendar year that results from the solar energy system shall be deemed to be electricity that the provider generated or acquired from a renewable energy system for the purposes of complying with its portfolio standard.

~~[5.]~~ ***4.*** The Commission shall adopt regulations that establish a system of portfolio energy credits that may be used by a provider to comply with its portfolio standard.

~~[6.]~~ ***5.*** Except as otherwise provided in subsection ~~[7,]~~ ***6,*** each provider shall comply with its portfolio standard during each calendar year.

~~[7.]~~ ***6.*** If, for any calendar year, a provider is unable to comply with its portfolio standard through the generation of electricity from its own renewable energy systems or, if applicable, through the use of portfolio energy credits, the provider shall take actions to acquire or save electricity pursuant to one or more renewable energy contracts or energy efficiency contracts. If the Commission determines that, for a calendar year, there is not or will not be a sufficient supply of electricity or a sufficient amount of energy savings made available to the provider pursuant to renewable energy contracts and energy efficiency contracts with just and reasonable terms and conditions, the Commission shall exempt the provider, for that calendar year, from the remaining requirements of its portfolio standard or from any appropriate portion thereof, as determined by the Commission.

~~[8.]~~ *7.* The Commission shall adopt regulations that establish:

(a) Standards for the determination of just and reasonable terms and conditions for the renewable energy contracts and energy efficiency contracts that a provider must enter into to comply with its portfolio standard.

(b) Methods to classify the financial impact of each long-term renewable energy contract and energy efficiency contract as an additional imputed debt of a utility provider. The regulations must allow the utility provider to propose an amount to be added to the cost of the contract, at the time the contract is approved by the Commission, equal to a compensating component in the capital structure of the utility provider. In evaluating any proposal made by a utility provider pursuant to this paragraph, the Commission shall consider the effect that the proposal will have on the rates paid by the retail customers of the utility provider.

8. Except as otherwise provided in section 4.7 of this act, the provisions of this section do not apply to a provider of new electric resources as defined in NRS 704B.130.

9. As used in this section:

(a) "Energy efficiency contract" means a contract to attain energy savings from one or more energy efficiency measures owned, operated or controlled by other parties.

(b) "Renewable energy contract" means a contract to acquire electricity from one or more renewable energy systems owned, operated or controlled by other parties.

(c) "Terms and conditions" includes, without limitation, the price that a provider must pay to acquire electricity pursuant to a renewable energy contract or to attain energy savings pursuant to an energy efficiency contract.

Sec. 9.3. NRS 704.7822 is hereby amended to read as follows:

704.7822 For the purpose of complying with a portfolio standard established pursuant to NRS 704.7821 ~~[,]~~ ***or section 4.7 of this act,*** a provider shall be deemed to have generated or acquired 2.4 kilowatt-hours of electricity from a renewable energy system for each 1.0 kilowatt-hour of actual electricity generated or acquired from a solar photovoltaic system, if:

1. The system is installed on the premises of a retail customer; and

2. On an annual basis, at least 50 percent of the electricity generated by the system is utilized by the retail customer on that premises.

Sec. 9.5. NRS 704.7823 is hereby amended to read as follows:

704.7823 1. Except as otherwise provided in subsection 2, any electricity generated by a provider using any system that involves drawing or creating electricity from tires must be deemed to have not come from a renewable energy system for the purpose of complying with a portfolio standard established pursuant to NRS 704.7821 ~~[.]~~ ***or section 4.7 of this act.***

2. For the purpose of complying with a portfolio standard established pursuant to NRS 704.7821 ~~[,]~~ ***or section 4.7 of this act,*** a provider shall be deemed to have generated or acquired 0.7 kilowatt-hours of electricity from a renewable energy system for each 1.0 kilowatt-hour of actual electricity generated or acquired from a system that utilizes a reverse polymerization process, if:

(a) The system is installed on the premises of a retail customer; and

(b) On an annual basis, at least 50 percent of the electricity generated by the system is utilized by the retail customer on that premises.

3. As used in this section:

(a) "Reverse polymerization process" means a process that generates electricity from a tire that:

(1) Uses microwave reduction; and

(2) Does not involve combustion of the tire.

(b) "Tire" includes any tire for any vehicle or device in, upon or by which any person or property is or may be transported or drawn upon land.

Sec. 9.7. NRS 704.7828 is hereby amended to read as follows:

704.7828 1. The Commission shall adopt regulations to carry out and enforce the provisions of NRS 704.7801 to 704.7828, inclusive ~~[.]~~ ***, and section 4.7 of this act.*** The regulations adopted by the Commission may include any enforcement mechanisms which are necessary and reasonable to ensure that each provider of electric service complies with its portfolio standard. Such enforcement mechanisms may include, without limitation, the imposition of administrative fines.

2. ***If a provider exceeds the portfolio standard for any calendar year, the Commission shall authorize the provider to carry forward to subsequent calendar years for the purpose of complying with the portfolio standard for those subsequent calendar years any excess kilowatt-hours of electricity that the***

provider generates, acquires or saves from portfolio energy systems or efficiency measures.

3. If a provider does not comply with its portfolio standard for any calendar year and the Commission has not exempted the provider from the requirements of its portfolio standard pursuant to NRS 704.7821 ~~[,]~~ ***or section 4.7 of this act,*** the Commission ~~[may]~~ ***:***

(a) Shall require the provider to carry forward to subsequent calendar years the amount of the deficiency in kilowatt-hours of electricity that the provider does not generate, acquire or save from portfolio energy systems or efficiency measures during a calendar year in violation of its portfolio standard; and

(b) May impose an administrative fine against the provider or take other administrative action against the provider, or do both.

~~[3.]~~ ***4.*** The Commission may impose an administrative fine against a provider based upon:

(a) Each kilowatt-hour of electricity that the provider does not generate, acquire or save from portfolio energy systems or efficiency measures during a calendar year in violation of its portfolio standard; or

(b) Any other reasonable formula adopted by the Commission.

~~[4.]~~ ***5.*** In the aggregate, the administrative fines imposed against a provider for all violations of its portfolio standard for a single calendar year must not exceed the amount which is necessary and reasonable to ensure that the provider complies with its portfolio standard, as determined by the Commission.

~~[5.]~~ ***6.*** If the Commission imposes an administrative fine against a utility provider:

(a) The administrative fine is not a cost of service of the utility provider;

(b) The utility provider shall not include any portion of the administrative fine in any application for a rate adjustment or rate increase; and

(c) The Commission shall not allow the utility provider to recover any portion of the administrative fine from its retail customers.

~~[6.]~~ ***7.*** All administrative fines imposed and collected pursuant to this section must be deposited in the State General Fund.

Sec. 10. NRS 704.873 is hereby amended to read as follows:

704.873 If a public utility that is subject to the provisions of NRS 704.736 to 704.751, inclusive, ***and section 4.3 of this act*** applies to the Commission for a permit for the construction of a utility facility:

1. The Commission has exclusive jurisdiction with regard to the determination of whether a need exists for the utility facility; and

2. No other permitting entity may consider, in its review of any application for a permit, license or other approval for the construction of the utility facility, whether a need exists for the utility facility.

Sec. 10.3. (Deleted by amendment.)

Sec. 10.5. NRS 704B.320 is hereby amended to read as follows:

704B.320 1. For eligible customers whose loads are in the service territory of an electric utility that primarily serves densely populated counties, the aggregate amount of energy that all such eligible customers purchase from providers of new electric resources before July 1, 2003, must not exceed 50 percent of the difference between the existing supply of energy generated in this State that is available to the electric utility and the existing demand for energy in this State that is consumed by the customers of the electric utility, as determined by the Commission.

2. An eligible customer that is a nongovernmental commercial or industrial end-use customer whose load is in the service territory of an electric utility that primarily serves densely populated counties shall not purchase energy, capacity or ancillary services from a provider of new electric resources unless, as part of the proposed transaction, the eligible customer agrees to:

(a) Contract with the provider to purchase:

(1) An additional amount of energy which is equal to 10 percent of the total amount of energy that the eligible customer is purchasing for its own use under the proposed transaction and which is purchased at the same price, terms and conditions as the energy purchased by the eligible customer for its own use; and

(2) The capacity and ancillary services associated with the additional amount of energy at the same price, terms and conditions as the capacity and ancillary services purchased by the eligible customer for its own use; and

(b) Offers to assign the rights to the contract to the electric utility for use by the remaining customers of the electric utility.

3. If an eligible customer is subject to the provisions of subsection 2, the eligible customer shall include with its application filed pursuant to NRS 704B.310 all information concerning the contract offered to the electric utility that is necessary for the Commission to determine whether it is in the best interest of the remaining customers of the electric utility for the electric utility to accept the rights to the contract. Such information must include,

without limitation, the amount of the energy and capacity to be purchased under the contract, the price of the energy, capacity and ancillary services and the duration of the contract.

4. Notwithstanding any specific statute to the contrary, information concerning the price of the energy, capacity and ancillary services and any other terms or conditions of the contract that the Commission determines are commercially sensitive:

(a) Must not be disclosed by the Commission except to the Regulatory Operations Staff of the Commission, the Consumer's Advocate and his staff and the electric utility for the purposes of carrying out the provisions of this section; and

(b) Except as otherwise provided in NRS 239.0115, shall be deemed to be confidential for all other purposes, and the Commission shall take such actions as are necessary to protect the confidentiality of such information.

5. If the Commission determines that the contract:

(a) Is not in the best interest of the remaining customers of the electric utility, the electric utility shall not accept the rights to the contract, and the eligible customer is entitled to all rights to the contract.

(b) Is in the best interest of the remaining customers of the electric utility, the electric utility shall accept the rights to the contract and the eligible customer shall assign all rights to the contract to the electric utility. A contract that is assigned to the electric utility pursuant to this paragraph shall be deemed to be an approved part of the resource plan of the electric utility and a prudent investment, and the electric utility may recover all costs for the energy, capacity and ancillary services acquired pursuant to the contract. To the extent practicable, the Commission shall take actions to ensure that the electric utility uses the energy, capacity and ancillary services acquired pursuant to each such contract only for the benefit of the remaining customers of the electric utility that are not eligible customers, with a preference for the remaining customers of the electric utility that are residential customers with small loads.

6. The provisions of this section do not exempt the electric utility, in whole or in part, from the requirements imposed on the electric utility pursuant to NRS 704.7801 to 704.7828, inclusive, ***and section 4.7 of this act,*** to comply with its portfolio standard. The Commission shall not take any actions pursuant to this section that conflict with or diminish those requirements.

Sec. 10.7. (Deleted by amendment.)

Sec. 11. Any public utility required to file a plan pursuant to NRS 704.741 that would not otherwise be required to file a new plan before January 1, 2011, shall submit an amendment to its existing plan by January 1, 2011, that complies with the provisions relating to a transmission plan in NRS 704.741, as amended by section 6 of this act.

Sec. 11.5. (Deleted by amendment.)

Sec. 12. The Public Utilities Commission of Nevada shall, not later than January 1, 2010, adopt regulations that designate renewable energy zones as defined in NRS 704.741, as amended by section 6 of this act.

Sec. 13. 1. This act becomes effective on July 1, 2009.

2. Sections 2 and 3 of this act expire by limitation on June 30, 2011.

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APPENDIX A-5

STATE OF NEVADA – EXECUTIVE ORDER 2011-18

State of Nevada

Executive Department

THE GREAT SEAL OF THE STATE OF NEVADA

ALL FOR OUR COUNTRY

Executive Order 2011-18

PROVIDING DIRECTION TO THE NEW ENERGY INDUSTRY TASK FORCE AND ESTABLISHING A TECHNICAL ADVISORY COMMITTEE THERETO

WHEREAS, renewable energy is important to the economy of the state and plays a role in the overall health, safety and welfare of the people of the State;

WHEREAS, Nevada is home to some of the most accessible renewable energy resources in the world, providing for clean, valuable electricity generation for the region;

WHEREAS, Nevada is a leader among the leaders in the nation to adopt policy that supports the development of our renewable resources;

WHEREAS, the Office of Energy plays a critical role in the development of a statewide plan for the promotion and proliferation of a sustainable and appropriate renewable energy industry;

WHEREAS, coordination of transmission planning and development is critical to the success of the renewable energy Industry in the State;

WHEREAS, the State needs to be an active participant in the regional renewable energy and transmission market and planning activities that are consistent with accepted and adopted regional plans;

WHEREAS, the State needs to insure that the public interest is served through the creation of a competitive energy market in a manner that is reasonable and not discriminatory or preferential;

WHEREAS, transmission facility developers should share similar benefits and obligations commensurate with their participation in the cost allocation of transmission development that is selected for inclusion in the State and/or regional transmission plan;

WHEREAS, fostering greater and more timely renewable energy development requires the State to establish a more cohesive and integrated statewide strategy, including greater coordination and streamlining of the siting, permitting, and improving the manner in which the transmission infrastructure is developed; and

WHEREAS, Article 5, Section 1 of the Nevada Constitution provides that, "The Supreme Executive Power of this State shall be vested in a Chief Magistrate who shall be Governor of the State of Nevada."

NOW, THEREFORE, by the authority vested in me as Governor by the Constitution and the laws of the State of Nevada, I hereby direct and order:

1. The New Energy Industry Task Force ("Task Force"), established by NRS 701.500 as amended, is hereby charged with facilitating the timely development of transmission facilities and renewable energy resources in this State, which includes without limitation facilitation of permitting, construction, and electrical interconnection of these facilities and resources.

2. The Task Force shall work with the Director to:

a) Identify and establish appropriate corridors for the transmission of electricity in this State recognizing Renewable Energy Zones adopted by the Public Utilities Commission pursuant to NRS 704.741(2)(b);

b) Promote the development and regionalization of transmission facilities and renewable energy resources in this state and in the western United States in a manner that is reasonable and not discriminatory or preferential; which considers the impacts to the citizens of the state of Nevada; and which creates an environment in this state that invites the development of these facilities;

c) Coordinate with existing electrical utilities, the Public Utilities Commission and other stakeholders on development of regional transmission planning and cost allocation strategies for interstate transmission facilities, while improving coordination for the development and construction of transmission facilities among local governments, between neighboring states and neighboring balancing authorities; and

d) Develop the business case from the perspective of Nevadans and our neighboring states necessary to develop our State's renewable resources and related industries with lowest possible risk to ratepayers.

3. The Nevada State Office of Energy and the Public Utilities Commission of Nevada will work collaboratively, and in coordination with the Task Force, with the intent to adequately plan and coordinate issues regarding transmission of renewable energy generation within the regional energy transmission market for the benefit of the State.

4. The Director of the Office of Energy shall form a Technical Advisory Committee to assist the Task Force in its work. Members of the Advisory Committee will not have a vote in the final recommendations of the Task Force and will serve at the pleasure of the Director with the express purpose of furthering the goals and mission of the Task Force. The Director shall ensure the Technical Advisory Committee includes representation from the Public Utilities Commission, Nevada Legislature, Board of Economic Development, Nevada System of Higher Education and such federal agencies or private enterprises as the Director deems necessary.

5. On or before August 1, 2012 the Task Force will present a report to the Governor demonstrating the business case for the production and transmission of renewable energy for native and regional load requirements.

6. On or before August 1, 2012 the Task Force will present a report to the Governor that recommends policy or regulatory changes that supports the goals of the Task Force.

7. On or before August 1, 2012 the Task Force will present a report to the Governor that clearly demonstrates the direction of the State as it pertains to long term regional transmission and cost allocation planning and in compliance with the Federal Electric Regulatory Commission Order 1000.

8. The Director of the Office of Energy shall coordinate efforts of the Task Force and other state, regional and federal organizations to carry out the orders as set forth in this Executive Order.

9. Meetings of the Task Force and Technical Advisory Committee shall be held in Carson City at the State Capital with members participating by video conference from the Grant Sawyer Building in Las Vegas if necessary.

10. To the extent this order conflicts with any previous executive order, this order controls.

IN WITNESS WHEREOF, I have hereunto set my hand and caused the Great Seal of the State of Nevada to be affixed at the State Capitol in Carson City, this 21st day of November, in the year two thousand eleven.

Governor of the State of Nevada

By the Governor:

Secretary of State

Deputy Secretary of State

APPENDIX A-6

INTERMOUNTAIN POWER AGENCY MEMBERS LIST

IPA
Intermountain Power Agency
Energy for Today & Tomorrow

ABOUT US | PARTICIPANTS SERVICE AREA | FINANCIAL INFORMATION | UPCOMING EVENTS | LINKS

Generation Entitlement Shares

California Purchasers

Los Angeles Department of Water and Power	44.617%
City of Anaheim	13.225%
City of Riverside	7.617%
City of Pasadena	4.409%
City of Burbank	3.371%
City of Glendale	1.704%
Total - 6 California Purchasers	74.943%

Utah Cooperative Purchasers

Moon Lake Electric Association, Inc.	2.000%
Mt. Wheeler Power, Inc.	1.786%
Dixie-Escalante Rural Electric Association, Inc.	1.534%
Garkane Power Association, Inc.	1.267%
Bridger Valley Electric Association	0.230%
Flowell Electric Association	0.200%
Total - 6 Cooperative Purchasers	7.017%

Utah Investor-Owned Purchasers

Utah Power & Light Company (PacifiCorp)	4.000%

Utah Municipal Purchasers

Murray City	4.000%
Logan City	2.469%
The City of Bountiful	1.695%
Kaysville City	0.739%
Heber Light & Power Company	0.627%
Hyrum City	0.551%
Fillmore City	0.512%
The City of Ephraim	0.503%
Lehi City	0.430%
Beaver City	0.413%

Parowan City	0.364%
Price	0.361%
Mount Pleasant	0.357%
City of Enterprise	0.199%
Morgan City	0.190%
City of Hurricane	0.147%
Monroe City	0.130%
The City of Fairview	0.120%
Spring City	0.060%
Town of Holden	0.048%
Town of Meadow	0.045%
Kanosh	0.040%
Town of Oak City	0.040%
Total - 23 Municipal Purchasers	14.040%

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