COUNTY OF HUMBOLDT
PLANNING AND BUILDING DEPARTMENT
CURRENT PLANNING DIVISION

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Hearing Date: November 14, 2019

To: Humboldt County Planning Commission

From: John H. Ford, Director of Planning and Building Department

Subject: **Humboldt Wind Energy Project Conditional Use Permit and Special Permit**
Record Number: PLN-13999-CUP
Assessor Parcel Numbers (APNs): 102-132-004 et al.
Monument and Bear River Ridges, Scotia, Shively, and Bridgeville areas

The attached staff report has been prepared for your consideration of the Humboldt Wind Energy Project Conditional Use Permit and Special Permit at the public hearing on November 14, 2019. The staff report includes the following:

Please contact Steve Werner, Supervising Planner at 268-3726 if you have any questions about the scheduled public hearing item.

Humboldt Wind Energy Project Conditional Use Permit and Special Permit
Record Number: PLN-13999-CUP
Assessor's Parcel Numbers (APNs): 102-132-004 et al.

Recommended Planning Commission Action
1. Describe the application as a continued public hearing.
2. Request that staff present the project.
3. Open the public hearing and receive testimony.
4. Provide direction to staff to prepare resolutions for project approval or denial; and
5. Continue the Public Hearing to November 21, 2019 at 4:00 PM.

1. Executive Summary

The Humboldt Wind Energy Project is a continued public hearing from the November 7, 2019 Planning Commission hearing. In advance of that hearing an executive summary was submitted to the commission summarizing the project description, changes to the project since publication of the DEIR, discussing the DEIR impact conclusions and providing detailed information on significant unavoidable impacts. At that hearing staff presented the project and gave an overview of the Final Environmental Impact Report. The Commission posed questions to staff and public testimony was received. A brief summary of the testimony was provided on November 8, 2019.

This staff report contains general responses to Planning Commission questions, the testimony received, and an approach to the statement of overriding considerations. Rather than submitting resolutions for your Commission to review, staff is seeking direction and will provide resolutions prior to the next public hearing on November 21, 2019.

2. Responses to Commissioner's Comments

Additional Mitigation and Financial Analysis

Commissioner Mitchell asked if there was a list of mitigation measures that were considered but rejected related to significant and unavoidable impacts, especially those posed by commenters, environmental groups and state agencies. Commissioner Levy requested more information related to additional mitigations and financial analysis. For mitigations that may have been rejected due to financial infeasibility he asked if there had been third party analysis of the project financial information.

Attachment A of this staff report includes a list of mitigation suggested in the comment letters received during the DEIR circulation and indicates whether the mitigation was already incorporated into the project, resulted in a revised mitigation measure, or rejected and why.

The Significant and Unavoidable Impacts identified in the DER and confirmed in the FEIR include the following:

Impact Area	Alternative Mitigation
Aesthetics • Visual Character • New Source of Light	Radar detection lighting
Air Quality • Construction Vehicle generation of NO_x	Add requirements to Mitigation related to alternative fuels, idling.
Biology • Operational Impacts on Marbled Murrelets • Operational Impacts on Raptors	Curtailment Identi-flight
Historical Resources • Tribal Cultural Resource – Bear River Ridge, Condor	No Project. – No Feasible mitigation

The applicant has provided two documents related to project financials- Financial Feasibility Analysis of Proposed Humboldt Wind Energy Project and Humboldt Wind Energy Project EIR Alternatives Financial Feasibility Analysis. These have not been independently reviewed by the County but they were prepared by a third party consultant to the applicant. These financial statements are Attachment B. The applicant will be prepared to address financial feasibility questions at the Hearing.

Tribal Cultural Resources

Commissioner McCavour questioned why Bear River Ridge was not eliminated from the project during scoping/ project planning due to the cultural resource impacts. Many commenters expressed concerns regarding Wiyot Tribe ancestral territory and the significant unavoidable impacts to Bear River Ridge, the associated ethnobotanical area, and the California condor, all of which have been identified as Tribal Cultural Resources.

The applicant has provided details as to why the project site was narrowed to Bear River and Monument Ridges. This can be found in Attachment B of the FEIR (*Wind Availability*

Analysis and Location of Project, Humboldt Wind, LLC, September 5, 2019). California has a limited number of suitable sites for wind energy development. Based on a review of wind resource maps, Humboldt Wind LLC initially identified southern Humboldt County generally as an area potentially suited for development of a utility scale wind energy project. After evaluating multiple locations, including Rainbow Ridge, Long Ridge, Bear River Ridge, Monument Ridge, Shively Ridge, and north of Bridgeville, all Non-Viable Sites were eliminated due to the lack of fundamentals required for a feasible wind project. The factors that contributed to the elimination of the numerous Non-Viable Sites included: 1) the lack of robust wind resource; (2) likely greater environmental impacts including biological and cultural resource impacts; (3) lack of access for turbine delivery; and (4) proximity to points of interconnection on the transmission grid with sufficient capacity.

During pre-application meetings with US Fish and Wildlife Service, California Department of Fish and Wildlife commented that Shively Ridge has higher potential than both Monument and Bear River Ridge to be a flyway for marbled murrelets given its position between the Eel and Van Duzen rivers. Construction of turbines on Shively Ridge also would have the potential to affect special status fish species and riparian habitat. Rainbow Ridge presented many of the same concerns. Development on that ridge would require construction of a bridge over the Bear River, which could affect special status fish species or marbled murrelet. Preliminary feedback in 2018 from USFWS and CDFW also suggested that Rainbow Ridge may have higher potential to support raptors than either Monument or Bear River Ridges. Rainbow Ridge also is a prominent feature on the landscape and has heightened importance to local tribes. A desktop analysis showed a higher potential for the discovery of cultural resources on Rainbow and Long Ridges than on the Proposed Project Site on Bear River Ridge and Monument Ridge. Through this process the project site was narrowed to Monument and Bear River Ridges.

Prior to preparing the Draft EIR Humboldt County held two public scoping meetings to inform interested parties about the proposed project, and to provide agencies and the public with an opportunity to provide comments on the scope and content of the DEIR. These meetings were held August 14 and 15, 2018. Testimony and written public comments were received. Although the need to initiate formal consultation under Assembly Bill (AB) 52 was acknowledged during the scoping, and that there may be archeological resources on Bear River Ridge, there was no mention of Bear River Ridge as a Tribal Cultural Resource.

As stated in the DEIR, initial AB 52 Consultation letters were sent on July 13, 2018, to the Big Lagoon Rancheria, the Hoopa Valley Tribe, the Bear River Band of the Rohnerville Rancheria, the Wiyot Tribe, and the Cher-Ae Heights Indian Community of the Trinidad Rancheria. The Bear River Band of the Rohnerville Rancheria and the Wiyot Tribe requested consultation.

A Cultural Resource Phase I Inventory Report (Stantec, 2018, confidential report) was prepared by a qualified archaeologist. During the preparation of this report a sacred lands search was requested from the Native American Heritage Commission (NAHC) on September 6, 2018, the purpose was to ascertain whether there were additional resources or locations that may be of importance to Native Americans who have traditionally resided in project area. On September 7, 2018 the NAHC responded that a review of their files yielded negative results.

The Cultural Resource Phase I Inventory Report (Stantec, 2018, confidential report) was submitted to the County on November 20, 2018 and provided to the Tribes on December 12, 2018. On February 13, 2019, a meeting was held with the County and Tribal Historic Preservation Officers of the Wiyot Tribe and the Bear River Band of the Rohnerville Rancheria. Additional Government-to-government tribal consultation was held between the County and the Wiyot Tribal Council on March 25, 2019.

It was during this consultation process that Bear River Ridge was discussed as a high prayer spot sacred to the Wiyot People. The ethnobotanical area and importance of the California Condor were also discussed.

Because this information was not available until later in the project design and because of the premier wind resource available on Bear River Ridge, the ridge was not eliminated from the project site. This impact was found to be significant and unavoidable with no feasible mitigation identified to reduce the impact.

In response to this information the County did include Alternative 5 in the DEIR, which is the avoidance of turbines on Bear River Ridge. This became the environmentally preferred alternative. However, this alternative was determined to be infeasible because it resulted in too few turbines and rendered it impossible to operate and finance the project.

The ethnobotanical area associated with Bear River Ridge is also a Tribal Cultural Resource. Although Mitigation Measure 3.6-3c (Incorporate Plants Appropriate for the Wiyot Tribe Ethnobotanical Area into the Reclamation, Revegetation and Weed Control Plan) it does not reduce the impact to a less than significant level. Testimony received from Adam Canter, the Wiyot Tribe ethnobotanist, indicated dissatisfaction with the draft Reclamation, Revegetation and Weed Control Plan regarding the reference to the Wiyot Tribe selecting "up to 100 plants to be salvaged and place into 1-gallon containers and/or up to 200 cuttings or plants less than 3-feet in height to be salvage and remain bare rooted during transfer to a location designated by the Wiyot Tribe." Because of this concern the County proposes a revision to this language to the following:

> <u>Plant species of environmental and cultural concern (listed in Appendix A of the Reclamation, Revegetation and Weed Control Plan in Appendix B of this FEIR) will</u>

be considered for salvage during construction. The applicant will coordinate with the representatives from the Wiyot Tribe to salvage plants and place them into 1-gallon containers and/or to salvage cuttings or plants less than 3 feet in height to remain bare-rooted during transfer to a location designated by the Wiyot Tribe. After plants have been salvaged and transported, the Wiyot Tribe will take responsibility for management and planting of the salvaged material.

This language eliminates the cap and allows for more coordination with the Wiyot Tribe on the number and selection of plants.

The California condor is a vital part of the creation story of many local Tribes. Representatives from the Yurok Tribe involved in the planned condor release program gave testimony at the hearing related to the anticipated release of the condors and weather they would be declared an non-essential/experimental (10j) population and if they would all be outfitted with transmitters during the life of the project. Mitigation Measure 3.6-4 (Detect Presence of and Curtail Operations for Condors) is based on the assumption that all condors will be outfitted with transmitters allowing them to be detected with a geofence which will send an alert and allow the turbine operators to turn off the turbines until the condor has passed through the area. Although, the assumption in the DEIR is that all condors would be outfitted with transmitters and that the risk would be low, it is still considered a significant unavoidable impact.

Risk may be higher if condors are not fitted with transmitters, however, the Northern California Condor Restoration Program Environmental Assessment (Redwood National Park, April 2018) notes that, “to date, no mortalities of California condors from wind turbine facilities have been recorded.” It also states that sources of mortality would be carefully monitored, and if high mortality rates were preventing the establishment of a self sustaining population, an Interagency Planning Team would coordinate with wind energy providers to implement measures to address collision threats, as has been done at other California condor release sites.

Although this remains a significant unavoidable effect, all feasible mitigation has been required.

Ultimately the impacts to Bear River Ridge, the associated ethnobotanical area and the California condor are significant and unavoidable. CEQA requires the evaluation and disclosure of impacts. Where impacts are found, avoidance is preferred, then minimization, and ultimate compensation is required whenever feasible. When even with all feasible mitigation, impacts still remain significant and unavoidable, a statement of overriding considerations is required. The contents of a proposed statement of overriding considerations is discussed later in this summary.

FAA Lighting Impact Analysis

Commissioner McCavour requested additional information about the impact analysis addressing lighting on the turbines. Many commenters expressed concern about the visual impact of these lights on neighboring communities.

The DEIR evaluates visual impacts, including as assessment of the proposed turbines and their associated lighting, in Section 3.2 "Aesthetics" and finds the impact to be significant and unavoidable. Turbine lighting is also discussed in the DEIR in Section 2.4.2, "Public Access and Safety," and in Section 3.9, "Hazards and Hazardous Materials." These sections address Federal Aviation Administration (FAA) requirements for lighting on the proposed turbines. Through its *Notice of Proposed Construction or Alteration* (Form 7460.1), the FAA would conduct a review of the proposed project before construction begins (Title 14, Part 77 of the Code of Federal Regulations). The turbines proposed under all generation options would be more than 200 feet tall and therefore would require the appropriate obstruction lighting. However, the FAA may determine that the absence of marking and/or lighting would not threaten aviation. As a result of its review process, the FAA might recommend installing tower markings or aviation safety lighting on all or only a portion of the turbine towers.

As described in DEIR Section 3.9, "Hazards and Hazardous Materials," construction of the turbines would follow the recommendations provided in the FAA Technical Note titled *Development of Obstruction Lighting Standards for Wind Turbine Farms* (DOT/FAA/AR-TN05/50). Design considerations would include appropriate paint and lighting that would increase visibility to pilots, thereby reducing potential aircraft accidents.

The applicant will work with the FAA to develop approaches to turbine lighting that would minimize visual impacts. The general standard for turbines over 499 feet, such as those proposed at the project, is to have two flashing red lights at the top of the turbine's nacelle. All turbines within this size category should be illuminated, regardless of their location within the wind farm. The flashing would occur simultaneously.

In 2016 the FAA approved the use of Aircraft Detection Lighting Systems (ADLS) which are sensor-based systems designed to detect aircraft as they approach an obstruction or group of obstructions. These systems automatically activate the appropriate obstruction lights until they are no longer needed by the aircraft. This technology reduces the impact of nighttime lighting on nearby communities and extends the life expectancy of obstruction lights. Even with this system it is likely that some portion of the turbines would still require the traditional lighting described above. The ADLS system needs to be approved by the FAA on a case by case basis. According to the applicant the cost to implement a program like this would range from $1 million to $1.5 million and that is an estimate that applies to sites that are on flat ground. The cost to implement the system would likely be higher given the terrain at the project site. The applicant has indicated that given the slim financial margin the project is operating on the ADLS system would be cost prohibitive.

Determination of Breeding Season

Commissioner McCavour requested clarifications about the statement "no construction during the breeding season." While she did not mention which species she was referring to specifically, presumably she was referring to northern spotted owl, as discussed during the staff presentation on wildlife. Commissioner McCavour wanted to understand how the breeding season was determined, and if there would be monitoring during construction activities to make sure nesting activities would not be affected.

The U.S. Fish and Wildlife Service (USFWS) defines the breeding season for northern spotted owls as March 1 – August 31, which is the period proven to be the best time to detect and document nesting. The actual breeding/nesting season may vary with latitude and elevation, and also with annual weather patterns.

Mitigation Measures 3.5-6: (Minimize Construction Disturbance to Northern Spotted Owl) requires the project applicant to maintain buffers from northern spotted owl activity centers during construction to prevent auditory or visual disturbance to nesting northern spotted owl. The mitigation measure requires those buffers to be established as described in USFWS guidelines (USFWS 2006) to prevent nest abandonment caused by auditory and visual disturbance.

The project gen-tie alignment was refined following circulation of the DEIR to include a 1,000-foot construction buffer from all activity centers, with the exception of one (Goat Rock, see Figure C-5 in Appendix C of the FEIR) where work will be avoided during the spotted owl breeding season.

The 1000-ft buffer from construction activities will provide sufficient protection to avoid auditory or visual disturbance during construction. A biological monitor will not be present to observe potential northern spotted owl nesting activities because the presence of a human observer near the nest (within the 1000-foot buffer) could pose visual or auditory disturbance to the nesting owls and could therefore adversely affect nesting success.

As for other birds for which there is no survey protocol, March through September brackets the breeding season for most birds. For raptors and non-raptors, Mitigation Measure 3.5-9 (Avoid Impacts on Nesting Raptors), and Mitigation Measure 3.5-13 (Avoid Impacts on Nesting Birds) require pre-construction surveys to be conducted during the appropriate period and require maintenance of non-disturbance buffers during construction to avoid impacts on nesting activities. In these cases, the actual "nesting" would be determined based on the ground surveys by qualified biologists.

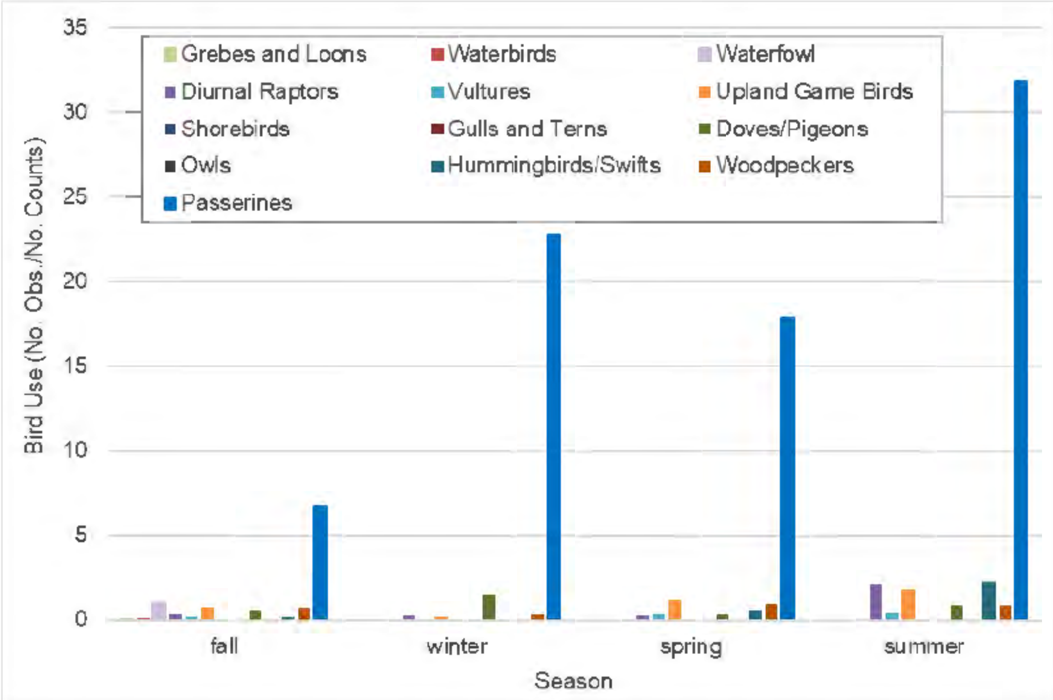
Number of Raptor Fatalities as a Percentage of Current Population

Commissioner McCavour requested context for the estimate of 114 raptor fatalities, stating that she would like to better understand what percentage of the current population those fatalities represent.

As described in the bird use report in Appendix J of the DEIR (*Humboldt Wind Energy Project Bird Use Count Report, Humboldt County, California, October 2017–October 2018*) the applicant collected quantitative avian use data in 2017 and 2018 to provide baseline data on bird species composition, frequency of occurrence, spatial and temporal use, and behaviors of all birds in the project area. The methods for the surveys were based guidelines from the California Energy Commission and California Department of Fish and Game (2007), and on USFWS Eagle Conservation Plan Guidance (USFWS 2013).

Surveys were conducted weekly for a year at 800-m plots in the project area and included both Bird Use Count targeting large birds (e.g., raptors, vultures, corvids, waterfowl) and Small Bird Use Counts focused mostly on passerine (perching) birds. The data from these surveys provided a comprehensive avian species list and information about the seasonal relative abundance of birds in the project area (see Graph 1 below from Appendix J in the DEIR), and if they were observed flying in what would become the "rotor swept zone" (i.e., 50–200 m above ground level) and therefore at risk of collision with turbine blades. These data helped inform the analysis of avian collision risk described in the DEIR. However, these data do not provide the information needed to develop a population estimate of local and regional raptors or non-raptors.

HUMBOLDT WIND ENERGY PROJECT BIRD USE COUNT AND SMALL BIRD USE COUNT SURVEY REPORT



Graph 1. Bird use by type per season documented during bird use counts at the Humboldt Wind Energy Project, Humboldt County, California, October 24, 2017–October 25, 2018.

See Table 1 below for a high-level estimate of numbers of raptors in California and in the United States for those species known to occur at the project site (from the Partners in Flight database). Please note that these data are not related to the project site.

Species	California Population Estimate	United States Population Estimate
Cooper's Hawk	64,000	790,000
Sharp-shinned Hawk	11,000	160,000
Northern Goshawk	3,000	120,000
Red-tailed Hawk	230,000	2,100,000
Red-shouldered Hawk	150,000	1,800,000
Ferruginous Hawk	220	87,000
Rough-legged Hawk	n/a	57,000
Bald Eagle	n/a	200,000
Golden Eagle	n/a	40,000
American Kestrel	200,000	2,000,000
Merlin	n/a	240,000
Prairie Falcon	6,500	95,000
Peregrine Falcon	n/a	37,000
Northern Harrier	24,000	520,000
White-tailed Kite	9,700	16,000

Table 1. Estimates of Raptor Populations in California and the United States

Any attempt to provide density estimates of local raptor populations or estimates of the percentage of the raptor population affected by project would be highly speculative because no accurate, quantitative information is available on the numbers of local and regional raptors. Furthermore, the raptor species present in the project area and their abundance varies considerably by season and location, with some species occurring as residents year-round, some as winter residents only, and yet others as migrants only; therefore, no single estimate of abundance would accurately characterize densities for the entire year.

Many sources of information are available about the relative seasonal abundance of local and regional birds, including Christmas Bird Count data, the Breeding Bird Atlas of Humboldt County, bird checklists at wildlife refuges, eBird (a popular birding app run by the Cornell Lab of Ornithology), and consultation with local bird experts. These sources provide a qualitative assessment of seasonal abundance. However, none offer the kind of quantitative information required to calculate densities or develop a useful estimate of the percentage of birds potentially killed by project operation relative to existing bird populations. Therefore, a percentage estimate is not provided as a component of the DEIR or FEIR analysis. The methods and results used in the EIR analysis as presented are consistent with industry standards and widely accepted by the regulatory agencies.

Timescale to Carbon Neutrality and Carbon Sequestration

Commissioner McCavour asked for information related as to what the timescale of the project would be to get to carbon neutrality. Many commenters also raised questions as to whether carbon sequestration from the forest was adequately accounted for. Many commenters mentioned the loss of old growth redwood forest or the ability of old growth forest to sequester carbon, however, no old growth forest will be removed as a result of this project.

We are still gathering information on this topic.

Purchase of Land Rather than Lease

Commissioner McCavour inquired as to whether land could be purchased rather than leased to compensate Tribes for the impacts. The land the project is located on is primarily the Russ Ranch and Humboldt Redwood Company. Neither of these entities have expressed any interest in selling their land. Additionally, the general plan and zoning of the site (Timber/ Agriculture Grazing and Timber Production Zone/ Agricultural Exclusive) have strict land division criteria. The Russ Ranch is also enrolled in a Williamson Act Agricultural Preserve. No subdivision under 600 acres would be allowed.

The County has requested that the applicant explore the ability to grant access on the project leased lands or if the applicant could lease additional lands on Bear River Ridge for the purpose of granting access. The applicant did explore this option however, the landowners have not been amenable to granting public access. The applicant ultimately does not have the legal authority to grant access. The project is on private land.

Consideration of Community Financial Benefits

Commissioner O'Neil requested more information about the financial benefits to the community and noted that several speakers had mentioned that the offshore wind project has pledged 5% returns to the community.

There are economic benefits to the community that would result in approving the Humboldt Wind Project. The project would develop a wind energy facility in Humboldt County that supports the local and regional economy by creating short- and long-term employment opportunities and increasing tax revenue. The project anticipates creating 15 full-time employment positions and approximately 300 construction jobs. The project will provide economic benefits to the County and its residents by increased spending in the community as a result of construction and development related work.

According to the applicant the project would result in an estimated 50 million dollars in tax revenue to the County over 30 years.

The Redwood Coast Offshore Wind Project is currently in the early stages of development and proposed by a consortium of companies that include EDPR, AkerSolutions and Principle Power in partnership with Redwood Coast Energy Authority(RCEA). The project would develop floating offshore platforms approximately 25 miles offshore from Eureka. Permitting of this project is expected to take 5 years or more. It would be the first-of-its kind in North America, it is expected to undergo close regulatory scrutiny and will almost certainly be more expensive than mature onshore wind technology. There are potential impacts to wildlife and fishing resources that have yet to be evaluated. Project development and permitting is in the early stages and will not be available in time to assist in meeting RCEA's long-term contract requirements in the initial years this includes 65% of renewable procurement under long term contracts of 10+ years by the 2021-2024 compliance period (State's SB 350 requirement) (RCEA , 2019; Studds, 2019).

While Redwood Coast Offshore Wind Project has expressed a commitment to maximizing benefit to the local community there has been no commitment to a specific percentage of the returns (Studds, 2019).

Decommissioning

Commissioner O'Neill inquired about project decommissioning and what restoration consists of. Project decommissioning is discussed in Section 2.5, "Project Decommissioning and Restoration," in Chapter 2, "Project Description," of the DEIR. As stated in Section 2.5, upon decommissioning of the facility, the turbines would be removed from the project site, and the materials would be reused, sold for scrap, or taken to an approved solid or hazardous waste facility. Any underground utility improvements would be abandoned in place. The above ground portions of the turbine pad foundations would be removed to a depth of approximately 1 foot below grade. The remaining foundation would be left in place, then covered and re-vegetated. Restoration of disturbed lands would occur in accordance with regulations and/or the landowner's contractual commitments. Through the conditions of approval for the project the County will be requiring a bond from the applicant to ensure sufficient funds are available to decommission the project and revegetate and restore disturbed areas. These responsibilities are tied to the project and would be transferred to any future owners of the project.

As stated in Section 2.5, decommissioning would require a separate discretionary permit from the County. An environmental analysis of decommissioning would be conducted during CEQA review required to issue the decommissioning permit. Restoration and reclamation of disturbed areas that would occur under decommissioning would be addressed in the CEQA document.

It should be noted that while the project lifespan is approximately 30 years the project may undergo a repower. Repowering would require discretionary review by the County and is subject to CEQA. It is not clear how changing technologies may change the structure of power generation and delivery in the next 30 years, and it would be speculative to attempt to predict the actions of the owner/operator 30 years into the future. CEQA discourages a lead agency from speculation. For either repowering or decommissioning a CEQA review would be conducted at the time the applicant seeks discretionary approvals to conduct the decommissioning or repowering.

Details of Why this Exact Location Was Selected

Commissioner Newman provided questions via email and requested more information about why this exact location was selected. The site selection is discussed in detail in Mater Response 1 Site Planning and Avoidance Measures contained in Chapter 2 of the FEIR. On the most basic level the site was selected because it offers premier wind resources and based on early coordination with agencies and site specific preliminary review appeared to have lower impacts than other nearby ridges that were eliminated from further study.

Increased Energy Independence for Humboldt County

Via email commissioner Newman asked if the project would allow Humboldt County to be less dependent on outside power. Our understanding is that it will not at this time.

Concerns from Other Tribes

Commissioner Newman asked if tribes other than the Wiyot and Yurok Tribe, who had representatives speak at the Hearing, have expressed concerns related to the project.

The County did participate in government to government consultation with the Bear River Band of the Rohnerville Rancheria. The consultation process is discussed in Chapter 3.6 (Cultural Resources, Including Tribal Cultural Resources) of the DEIR. Bear River Band of the Rohnerville Rancheria was concerned about the condor and impacts at the Bridgeville substation. At the time of publication of the DEIR it was assumed there would be no excavation at the Bridgeville substation. However, since the release of the DEIR, the applicant has determined that excavation will be required within the footprint that was identified in the DEIR. Because of this change, the site has been subjected to surface and subsurface investigations to determine whether significant cultural resources are present in the area of expansion. These studies resulted in data that indicated that while significant cultural resources are present at Bridgeville, the portion of the site that occurs in the expansion area lacks integrity and is not eligible for inclusion in the California Register of Historic Resources/National Register of Historic Places. This report has been provided to the Bear River Band of the Rohnerville Rancheria.

No other Tribes requested consultation.

3. Responses to Public Testimony

Several themes emerged with multiple commenters asking questions or giving testimony on similar or related subjects. The main themes not included in the questions from the commissioners addressed above, are discussed below.

Changes to the Beauty of Humboldt County

Many commenters expressed deep concern for the visual resource impacts and the fundamental change the project would cause to the beauty of Humboldt County. Commenters noted that the natural beauty is the reason many people call Humboldt home and also the reason people come from all over the world to see the Redwoods.

The Visual Resource Report (Stantec, 2018) prepared for the project provided visual simulations from key observation points within 20 miles of the project site. Even at over 15 miles away, turbines will be visible from Table Bluff County Park, the farthest of the key observation points. Monument and Bear River Ridges are some of the most prominent features of the natural landscape and, especially from the north, are highly visible from many communities and vantage points. There is no doubt this project represents a fundamental change to that visual landscape and will for all practical purposes, permanently alter views. This is disclosed as a significant and unavoidable impact. And whether this is acceptable is a fundamental question your Commission will need to address, weighing the impacts against the benefits of the project.

Fire Danger

Fire danger from both the gen-tie line and fire that could be generated from the turbines was a topic of concern for several commenters.

Causes of fire at wind turbines are short circuits, overheating, overloading and lightning strikes. A small fire can accelerate quickly in a nacelle because these are made from highly flammable resin fiber glass. Internal insulation, which can become contaminated by oil deposits, further adds to the fuel load. Lightning strikes pose a uniquely high risk due to both the turbines' exposed locations and their height.

A review of publicly available accident data for worldwide wind energy facilities[1] indicates that between 2000 and 2019 an average 19 turbine fires occurred worldwide on annual basis (Table 1). In comparison with other energy industries, fire accidents are much less frequent in wind turbines than other sectors, such as oil and gas, which globally has thousands of fire accidents per year.

Table 1 Summary of Fire Accidents Worldwide Year 2000 to 2019

Fire

Fire is the second most common accident cause in incidents found. Fire can arise from a number of sources - and some turbine types seem more prone to fire than others. A total of 379 fire incidents were found:

By year:

Year	Before 2000	2000-2004	05	06	07	08	09	10	11	12	13	14	15	16	17	18	*19
No.	7	63	14	12	21	17	18	16	22	23	26	19	21	28	25	27	20

** to 30 September 2019*

The biggest problem with turbine fires is that, because of the turbine height, the fire brigade can do little but watch it burn itself out. While this may be acceptable in reasonably still conditions, in a storm it means burning debris being scattered over a wide area, with obvious consequences. In dry weather there is obviously a wider-area fire risk, especially for those constructed in or close to forest areas and/or close to housing or work places. Five fire accidents have badly burned wind industry workers.

NFPA 850 is the National Fire Protection Association's recommended practice for protection of electric generating plants and high-voltage direct current converter stations. Chapter 10 of NFPA 850 identifies hazards and protections for wind-power facilities and makes recommendations to address the safety of construction and operating personnel, physical integrity of components, and the continuity of plant operations.

NFPA 850 requires the development of a Fire Protection Design Basis Document that identifies relevant hazards -- such as the presence of fuels, lubricating oils, flammable liquids, electrical equipment, and dust explosions -- along with how the project will be protected. The proposed project would meet the standards outlined in NFPA 850.

As discussed in Chapter 2.0 "Project Description" of the DEIR, the project includes a Supervisory Control and Data Collection System (SCADA) which is an integrated system to monitor, gather and process data on the operations of the wind turbines. The project is also incorporating automatic fire detection and suppression systems to help protect the nacelle (Figure 1). There are a number available, but the most common solution

[1] Caithness Windfarm Information Forum (CWIF) http://www.caithnesswindfarms.co.uk/AccidentStatistics.htm, accessed November 9, 2019.

provides component-level automatic systems that offer both fire detection and suppression in a single package. Designed to detect a small fire in or around a critical component, they improve the response time and reliability while reducing the size of the system required.

Interest in Offshore Wind or Community Solar as an Alternative to this Project

Many commenters postulated that rooftop solar and or the offshore wind project would be a preferable substitute to the Humboldt Wind Project.

The proposed project as revised in the FEIR would generate 147 MW of energy. Although roof top solar can be a valuable part of diversifying California's energy portfolio, solar alone cannot replace the megawatt generating capacity of a commercial scale wind project. "There are about 63,000 homes in Humboldt County. If every home had a sunny rooftop and if we installed 3 kW of solar panels on every one, we'd get about 230,000 MWh per year of solar electricity. Even in this mythical scenario, that's less than half the output of Terra-Gen's wind farm." (Letter, Peter Lehman, Arcata Northcoast Journal, July 11, 2019.)

The offshore wind project was discussed in part above in the response to commissioner's comments.

Potential Reduction in Property Values

Several commenters expressed concerns related to a reduction of property values.

In 2013, a nationwide study was conducted using a randomly drawn, representative national survey of 1705 existing U.S. wind projects to statistically examine factors that affect attitudes toward wind projects. The result is the first-ever nationally representative analysis of this topic. The study looked at data from more than 50,000 home sales among 27 counties in nine states. These homes were within 10 miles of 67 different wind facilities, and 1,198 sales were within 1 mile of a turbine. The data span the periods well before announcement of the wind facilities to well after their construction.

Based on statistical analysis the authors found no statistical evidence that home values near turbines were affected in the post-construction or post-announcement/pre-construction periods.[2] Previous research on potentially analogous disamenities (e.g., high-voltage transmission lines, roads) suggests that the property-value effect of wind turbines is likely to be small, on average, if it is present at all potentially helping to explain why no evidence of an effect was found in the present research.

Interest in the Project's Contribution to Combating Global Climate Change

[2] Hoen†, Wiser, Cappers. A Spatial Hedonic Analysis of the Effects of Wind Energy Facilities on Surrounding Property Values in the United States, Lawrence Berkeley National Laboratory, August 2013.

Five of the commenters expressed that due to the urgency of the climate change crisis they were in support of the project. A report published by BioScience on November 5, 2019, included signatories of more than 11,000 scientists worldwide and declared that "the Earth if facing a climate emergency".

Assuming the turbines operate at a net capacity factor of 40%, the project could remove the equivalent of:

- Greenhouse gas emissions from: 81,543 passenger vehicles driven for one year or 939,041,201 miles driven by an average passenger vehicle; ORCO2 emissions from 43,216,817 gallons of gasoline consumed or 37,727,687 gallons of diesel consumed, or 419,872,936 pounds of coal burned; or
- 2,095 railcars' worth of coal burned, or 889,198 barrels of oil consumed, or 15,700,582 propane cylinders used for home barbeques; or
- .099 power plants in one year or 48,973,382,083 smartphones charged; or
- Greenhouse gas emissions avoided by: 133,961 tons of waste recycled instead of landfilled, or 19,136 garbage trucks of waste recycled instead of landfilled, or 16,757,618 trash bags of waste recycled instead of landfilled, or 81.4 wind turbines running for a year, or 14,588,364 incandescent lamps switched to LEDs; or
- Carbon sequestered by: 6,350,643 tree seedlings grown for 10 years, or 452,018 acres of U.S. forests in one year, or 3,117 acres of US forests preserved from conversion to cropland in one year.

(See attached Greenhouse Gas Equivalencies Calculator, US EPA printout, https://www.epa.gov/sites/production/files/widgets/ghg-calc/calculator, Accessed: 12 November 2019.)

4. Other Comments

Raptor Mitigation

One of the commenters stated that the mitigation for take of each eagle, as stated in the FEIR was $600 donated to a wildlife care center for each bird taken. This statement does not accurately characterize the mitigation proposed for eagles and other raptors. For eagles, Mitigation Measure 3.5-5c: (Implement Compensatory Mitigation to Offset Operational Impacts on Eagles), requires the applicant to compensate for the loss of each golden or bald eagle injured or killed as a result of project operation by paying for the retrofitting of electrical utility poles that present a high risk of electrocution to eagles, as prescribed in the Eagle Conservation Plan Guidance, Appendix G (USFWS 2013). This is an industry standard method approved by the USFWS, the agency charged with the protection of eagles.

For raptors, Mitigation Measure 3.5-11: (Avoid, Minimize, and Compensate for Operational Impacts on Raptors) has been augmented in the FEIR (compared to what was presented in the DEIR) with two additional measures, as follows:

- Undergrounding 5 miles of existing overhead PG&E electrical distribution lines that represent existing electrocution and collision hazards for raptors;
- and donations of $600/raptor to a raptor rehabilitation facility.

Both of these measures will benefit raptors, along with the remainder of the Mitigation Measures, as previously proposed. While the $600 payment is tied to loss of individual raptors, it is part of a much more comprehensive approach to raptor mitigation, some of which will occur regardless of raptor fatalities that might occur as a result of the project.

The commenters remarks are therefore taken out of context and not accurate, as stated.

Prey Management Program

Several commenters expressed concern about the prey management program mentioned in Mitigation Measure 3.5-5a (Avoid, Minimize, and Compensate for Operational Impacts on Eagles) because of potential impacts on raptor species and mammals from rodenticide use.

The prey management program was intended to refer to reducing the potential attraction of eagle prey with a vegetation management approach and by removing construction debris from the site to eliminate cover for rodents and other prey from areas near the turbines. The applicant will be required to follow good housekeeping practices during operations, which includes the removal of potential attractants for eagles to the turbine pad areas, such as dead wildlife or wildlife parts (carcasses and offal of large mammals during hunting season, etc.).

As shown below and in Chapter 9 of the FEIR, the reference to a prey management program has been deleted to avoid confusion about the potential use of rodenticides/anti-coagulants which was not intended to begin with.

Mitigation Measure 3.5-5a: Avoid, Minimize, and Compensate for Operational Impacts on Eagles.

> The project applicant shall design and operate the project to minimize potential operational impacts on eagles by adhering to the following impact avoidance and minimization measures:
>
> - Maintain a landscape around WTGs that does not encourage raptor occurrence by maintaining rodent prey populations to relatively low levels. ~~In addition, implement a prey management program to reduce the availability of rabbits, ground squirrels, and other prey that could attract eagles and other raptors.~~

Marbled Murrelet Mitigation Strategy

One commenter suggested that the marbled murrelet mitigation strategy based on reducing predation by corvids would be ineffective because 2/3 of the predation on marbled murrelet nests is by reptiles and mammals.

Predation risk to marbled murrelet from avian predators is considerably significantly higher than from mammals or reptiles. While it is difficult to estimate the predation impacts of the complete suite of predators (birds and mammals) it is clear that corvids, especially Steller's jays and common ravens, are the most common nest predators across the range of the marbled murrelet (McShane et al. 2004, Nelson and Hamer 1995, Piatt et al. 2007).

Regarding the comment about reptiles as nest predators, the commenter did not indicate which reptile species might prey on marbled murrelet eggs or nestlings, but there are no arboreal reptiles known to occur in the project area.

The mitigation strategy for marbled murrelets included in Appendix B of the FEIR is based on the best available science and was developed by a leading expert in the field of marbled murrelet ecology, and independently peer reviewed; therefore, it was deemed adequate to mitigate impacts on marbled murrelets resulting from the proposed project.

Please note that despite the proposed mitigation, the impact conclusion of the DEIR as "significant and unavoidable" remains unchanged.

Wet Season Construction

One commenter stated that wintertime operations would violate the Humboldt Redwood Company Habitat Conservation Plan.

Regarding the relationship of the project with the HRC HCP please see Master Response 8, "*Conflict with Adopted HCP*." Mitigation Measures 3.5-22a through 3.5-24e of the DEIR require the implementation of erosion control measures for disturbed areas and other Best Management Practices (BMPs) intended to avoid sediment input to watercourses and adverse effects on water quality and fish habitat. These measures include erosion control measures outlined in the Stormwater Pollution Prevention Plan (SWPPP), storm-proofing of roads, driving restrictions during the wet months, and revegetation of disturbed areas after construction. Monitoring would be conducted to determine the effectiveness of BMPs. In addition to submitting water quality monitoring data to the Regional Water Quality Control Board, monitoring results will be also be submitted to the County. If monitoring shows exceedance of any standards in the SWPPP, the County has the ability to impose a temporary shutdown of construction. Please note that these measures apply throughout the project area, which parcels are owned by HRC and therefore subject to the HCP, and parcels owned by private entities and not subject to the HCP.

Adequacy of Bird Surveys

One of the commenters from the public expressed concerns about the adequacy of the bird surveys, stating that the eagle surveys were conducted for just one hour once/month, and that the surveys underestimated the raptor use of the project area and the impacts, based on her experience with studying raptors in the project area.

The commenter has not accurately characterized the methods used during the eagle use surveys, which were conducted over a 2-year period in accordance with methods described in the USFWS's Eagle Conservation Plan Guidance (USFWS 2013). The proposed eagle survey methodology was reviewed by the USFWS before implementing the surveys.

Eagle use surveys were conducted using 13, 800-m radius survey plots that covered approximately 53% of the project area; 36 of the 47 proposed turbine locations were located within the 800-m radius survey plots. The total survey effort was 112 hours and 129.75 hours in 2018 and 2019, respectively.

A detailed description of the methods and results of the2018 and 2019 eagle use surveys are available in Appendix H in the DEIR (H*umboldt Wind Energy Project Eagle Use Survey Report, Humboldt County, California, October 2017–October 2018* prepared by Stantec Consulting Service, Inc., dated September 3, 2019) and Appendix B in the FEIR (*Eagle Use Count Survey Results Memo November 2018 - August 2019*, prepared by Stantec Consulting Service, Inc., dated September 3, 2019).

As discussed in the response to comment #1 above, the commenter also has not correctly characterized the methods used for Bird Use Counts and Small Bird Use Counts (see Appendix J of the DEIR (*Humboldt Wind Energy Project Bird Use Count Report, Humboldt County, California, October 2017–October 2018*)). The applicant developed a comprehensive species list of all birds observed during the avian use surveys. This list includes the raptor species mentioned by the commenter.

The methods and results presented in the DEIR and FEIR are consistent with methods routinely used to support these types of analyses.

CEC/CDFW Guidelines Category 3 vs 4

Multiple commenters mentioned that this site was a "Category 4". This was referring to the California Energy Commission (CEC) and California Department of Fish and Wildlife (CDFW) California Guidelines for Reducing Impacts to Birds and Bats from Wind Energy Development CEC/CDFW Guidelines which categorize sites based on appropriateness for siting wind facilities. The FEIR contains a detailed discussion of this topic in Chapter 4 State Comment Responses (Comment S4-4).

The Guidelines were developed 12 years ago to provide a voluntary framework for project developers and permitting resource agencies, including the commenter, to use while screening potential wind development sites and to recommend protocols for gathering background data to use while analyzing impacts. The recommendations and protocols discussed in the Guidelines are intended to be suggestions for local permitting agencies to use at their discretion.

Under the Guidelines, wind development should not be considered in Category 4 sites. The Guidelines provide two criteria for determining whether a site is included in Category 4:

> (1) "land sites that are protected by local, state, or federal government such as a wilderness area, park, monument, or wildlife or nature preserve," and, potentially,
>
> (2) sites where there is an unacceptable risk of bird or bat fatalities, particularly if no feasible avoidance or mitigation measures are available to reduce impacts.

The Guidelines also describe a Category 3 site as: "Project Sites with High or Uncertain Potential for Wildlife Impact."

Although CDFW indicated in their comments that they considered the site was a Category 4, the County has considered the Guidelines in assessing the environmental impacts of the proposed project and found the site to be a Category 3.

Per the Guidelines, projects with high levels of bird and bat use or risk will need more study to help understand and formulate ways to reduce the number of fatalities". The project applicant has followed the recommendations in the Guidelines by engaging in intensive surveying, including protocol-level surveys for a variety of special-status species and baseline studies for numerous other species. The results of these surveys are presented in numerous appendices to the DEIR and Appendix C of the FEIR.

5. Discussion of Statement of Overriding Considerations

As mentioned in this summary and in the summary received for the Hearing on November 7, 2019, there are significant unavoidable impacts associated with the project. Those brought up most prominently during the hearing on November 7, 2019 included significant unavoidable impacts to Tribal Cultural Resources and Aesthetics. If approving a project where significant unavoidable impacts have been identified, a statement of overriding considerations must be adopted. CEQA requires the decision-making agency to balance the economic, legal, social, technological, or other benefits, including regionwide or statewide environmental benefits, of the project against its unavoidable environmental risks in determining whether to approve the project. If these benefits outweigh the project's unavoidable, adverse environmental impacts the identified significant unavoidable impacts may be considered acceptable.

Staff has identified the following benefits associated with the project.

There are statewide environmental benefits of the project. The Legislature passed the California Global Warming Solutions Act of 2006 (AB 32) creating a multi-year program to reduce greenhouse gas emissions in California. The California Air Resources Board (ARB) was delegated the task of developing a Scoping Plan to develop the approach to reduce GHGs to achieve the goal of reducing emissions to 1990 levels by 2020. In 2016, the Legislature passed SB 32 and adopted a GHG reduction target of 40 percent below 1990 levels by 2030. Senate Bill 350, signed into law in 2015, requires a statewide portfolio standard to ensure that renewable resources account for 50 percent of California's electrical load by 2030. The recently enacted SB 100 moves up the deadline for reaching the 50 percent milestone to 2026, stepping to 60 percent by 2030. Further, the state has a goal of reducing GHG emissions by 80 percent below 1990 levels by the year 2050. ARB established a Scoping Plan detailing the requirements for renewable energy targets. (California Air Resources Board, AB 32 Scoping Plan, available at https://ww3.arb.ca.gov/cc/scopingplan/scopingplan.htm, Accessed: 6 November 2019; California Climate Policy Dashboard, BerkeleyLaw, University of California, https://www.law.berkeley.edu/research/clee/research/climate/climate-policy-dashboard/, Accessed: 6 November 2019.)

California's Renewables Portfolio Standard (RPS) requires all electricity retailers in the state, including publicly owned utilities (POUs), investor-owned utilities, electricity service providers, and community choice aggregators, to adopt RPS goals of obtaining 50 percent of the state's electricity from eligible renewable energy resources by 2030. (RPS Eligibility Guidebook, (Ninth Edition, Revised), available at California Energy Commission, https://www.energy.ca.gov/programs-and-topics/programs/renewables-portfolio-standard (Accessed 6 November 2019).) Wind facilities that generate electricity may qualify for RPS certification. (*Id.*)

Wind energy is a renewable energy source. (*See, e.g.*, American Wind Energy Association, https://www.awea.org/wind-101/benefits-of-wind, Accessed: 6 November 2019.) The project will assist California in meeting the ambitious RPS goals of 50 percent of the state's electricity from eligible renewable energy resources by 2030.

The project would contribute to a diversified statewide energy portfolio that will reduce exposure to price volatility associated with electricity and natural gas. The project would displace emissions of approximately 384,068 metric tons per year of carbon dioxide that would otherwise be required to generate the same amount of electricity as this 147 MW project.

There are local and regional environmental benefits of the project. Approval of the project will aid the County in meeting energy needs in an efficient and environmentally sound manner, as provided in the County General Plan, which encourages utilization of renewable energy resources. Specifically, the project would allow the County to further the following Policy Goals as stated in Chapter 12, Energy Element, of the General Plan:

Policy E-G3, Supply of Energy from Local Renewable Sources, which calls for increased local energy supply from a distributed and diverse array of renewable energy sources and providers available for local purchase and export. The project would increase local energy supply for a distributed and diverse array of renewable energy sources and providers available for local purchase and export. The project will increase locally produced renewable energy for local consumption and export. The project will be privately owned and operated, and although it will feed into the PG&E grid, it will be controlled by a separate energy provider.

The Project would further Policy E-P3, Local Renewable Energy Supply, which calls for the County to support renewable energy development projects including biomass, wind, solar, "run of the river" hydroelectric, and ocean energy that increases local energy supply. This is a renewable energy wind project that increases local energy supply.

This Project would also further Policy E-P13, Incentives for Using Alternative Energy which calls for the County to encourage the use of renewable energy and environmentally preferable distributed energy generation systems in the county. The Project would provide 147 MW of renewable energy.

The Redwood Coast Energy Authority (RCEA), a local government Joint Powers Agency whose members include the County of Humboldt, the Cities of Arcata, Blue Lake, Eureka, Ferndale, Fortuna, Rio Dell, and Trinidad, and the Humboldt Bay Municipal Water District, has set a target of 100% clean and renewable electricity by 2025. (Stephenson, Nancy, 100% Clean and Renewable Electricity by 2025, Redwood Coast Energy Authority, April 8, 2019, https://redwoodenergy.org/100-clean-and-renewable-electricity-by-2025/, Accessed: 8 November 2019.) This Project would help RCEA and its members to achieve that goal.

The economic benefits of the project were discussed above in the response to commissioner's comments, and include additional jobs and tax revenue.

There are also benefits to the knowledge base. Mitigation Measure 3.5-18a calls for the formation of a Technical Advisory Committee to minimize the risk of bat mortality and to preclude the project's contribution to significant impacts on local and regional bat populations. The TAC is tasked with evaluation of postconstruction monitoring data to determine whether bat mortality attributable to the project poses a potential for significant impact on the local and regional bat population if left unabated. The formation and operation of the TAC will allow the local (and national) scientific community to study specific populations of bats known to occur in the region, including the hoary bat, and to understand population trends in general, as well as the impacts of the project on the population. This will contribute to the greater scientific knowledge base and support future environmental analyses and mitigations.

6. Next Steps

After recommends that the Planning Commission receive the staff presentation, allow the applicant time to address questions raised at the last hearing, and allow public testimony. At the conclusion, staff requests that the Planning Commission asks questions to staff and the applicant. Staff is seeking direction from the Commission to prepare resolutions for either approval or denial of the project and that the public hearing be continued to November 21, 2019.

Attachment 1: MITIGATION MEASURES SUGGESTED IN COMMENTS TO DEIR AND RESPONSES

Ref	Comment	Response	MM
S2-1	The DEIR should develop a marbled murrelet mitigation plan using a finalized take estimate that has been reviewed and accepted by CDFW and USFWS. The mitigation plan should propose feasible mitigation that fully mitigates for the anticipated take of marbled murrelet.	Please see Master Response 2. The marbled murrelet mitigation plan was reviewed and discussed with both CDFW and USFWS. The modeling for the mitigation was discussed with CDFW after the issuance of the DEIR. As discussed in Master Response 2 the project has been modified with a reduction in the number of turbine to result in 7.77 marbled murrelet fatalities. The corvid management program in contrast is projected to result in reproductive success for 48 to 97 murrelets over the life of the project, resulting in a net benefit to the species.	3.5-2c
S2-1	The DEIR should include mitigation for the total loss of NSO habitat, including habitat lost via timber removal conducted by HRC on behalf of the Project, because its removal is permanent and inconsistent with the HRC HCP activities. The DEIR should include a NSO mitigation plan with performance standards, enforceable terms, and sufficient detail to allow meaningful public review of both the impacts and proposed mitigation.	In the FEIR, Master Response 3 and the revisions to the Biology section in Chapter 9 addressing NSO identify that mitigation is required for permanent impacts and edge effect impacts. This is independent of the HCP. There is a mitigation plan with performance standards requiring set aside of replacement habitat and encourages barred owl management.	3.5-7
S2-1	The DEIR should propose habitat retention thresholds for NSO as recommended in USFWS Attachment A, and identify, based on the proposed Project footprint, whether these habitat retention thresholds can be met.	As part of the information provided for the FEIR, the applicant provided a memo titled: "*Northern Spotted Owl Activity Center Occurrences Discussion and Figures.*" This memo identifies the habitat retention goals from the HCP and concludes that the project would not prevent HRC from meeting the habitat retention goals set forth in the HCP.	
S2-1 O9-15	The DEIR should include specific information about formation of a TAC. The TAC's structure and authority must be clearly defined to establish how TAC recommendations are made, to whom, and whether these recommendations are binding and enforceable by the Lead Agency. … convene a TAC before project implementation. The mitigations identified by the TAC can then be tested in year 1 of	Mitigation Measure 3.5-18a has been refined and expanded to incorporate suggestions from commenters. This includes the provision that the TAC be formed 4 months before operation.	3.5-18a

MITIGATION MEASURES SUGGESTED IN COMMENTS TO DEIR AND RESPONSES

Ref	Comment	Response	MM
	operation and mitigation measures can be improved through monitoring data.		
S2-1	The TAC should include multiple third-party subject-matter experts. The TAC, in consultation with wildlife agencies and the Lead Agency, should provide input and concurrence on monitoring, and should evaluate impacts and propose solutions for bird and bat related mortalities. Compensatory mitigation that is roughly proportional and fully enforceable should be proposed to mitigate impacts to birds and bats to less than significant.	No TAC is proposed for Birds. Mitigation Measure 3.5-14 has been refined to address requests from commenters for clarification about proposed compensatory mitigation. Language has been added in the final bullet of the mitigation measure, “Report Take,” to clarify that the compensatory mitigation would be required only if CDFW or USFWS specified compensatory mitigation for take of a listed species, not for take of other nonraptor birds. No compensatory mitigation for nonraptor birds is necessary because operational impacts on nonraptor birds will be less than significant. Mitigation Measure 3.5-11 (Operational Impacts on Raptors) has been revised, as described in “Operational Impacts on Raptors,” in Section 3.5 in Chapter 9 of this FEIR. Mitigation Measure 3.5-11 now includes undergrounding of an overhead line that represents electrocution risk to raptors and requirement to pay $600/raptor to a raptor rehabilitation facility in addition to the compensatory mitigation of removal of existing power lines that pose electrocution hazard to raptors.	3.5-14 3.5-11
S2-1 O2-3 O7-5	Operational mitigation for bats during the fall season (September – October at minimum) should be implemented upon commencement of Project operations. This should include raising cut-in speeds to at least 5.5 meters per second, or greater if recommended by the TAC. Please identify whether the Project will implement the American Wind Energy Association’s policies to limit blade movement in low wind speeds. Please indicate whether the Applicant will agree to implement operational curtailment as a mitigation strategy to reduce bird and bat fatalities.	Two new mitigation measures, Mitigation Measure 3.5-18d (Implement Operational Minimization Measures and Mitigation), and Mitigation Measure 3.5-18e (Implement American Wind Energy Association Best Management Practices) has been added to refine the language from the DEIR.	3.5-18d 3.5-18e

MITIGATION MEASURES SUGGESTED IN COMMENTS TO DEIR AND RESPONSES

Ref	Comment	Response	MM
O9-17	Based on available science, operational curtailment is feasible as well		
S2-1	As described in the DEIR, the Project is highly likely to result in take of numerous raptor species including FP species. If take of FP species is unavoidable, the Project should develop an NCCP to authorize this take. Biological monitoring and “informed curtailment” (rapid shut down turbines when raptors are seen approaching), or other technology to detect raptors and shut down turbines accordingly, may be a feasible mitigation to avoid take of these species at this location.	See Above	3.5-11
S2-1	The DEIR should provide information about rodent control and the proposed prey management program described in mitigation measure 3.5-5a, and evaluate any potentially significant impacts that this mitigation may cause, as required by CEQA §15126.4 (a)(1)(D).	Mitigation Measure 3.5-5a (Avoid, Minimize, and Compensate for Operational Impacts on Eagles) has been revised as described in “Operational Impacts on Bald and Golden Eagles,” in Section 3.5 of Chapter 9 of this FEIR. The proposed rodent prey management plan has been removed from this measure because of concerns about feasibility and potential unintended impacts on other ecosystem components.	3.5-5a
S2-1	Scent detection dogs should be used as part of a robust bat and bird fatality monitoring plan.	The use of dogs is one method that could be employed to increase the detection probability of carcasses. To meet the detection performance standards, the applicant will implement a variety of fatality survey search methods best suited to achieving the best results. These methods include searcher efficiency and carcass persistence trials, and search method variables, such as plot size, habitat mapping, habitat maintenance, search transect spacing, search interval, and the use of scent dogs. Therefore, the use of dogs is recognized as one of several methods that may be used during the fatality surveys to maximize benefit.	
S4-6	Murrelets fly inland less frequently during the non-nesting season, and shutting off wind turbines (i.e. curtailment) during	Since circulation of the Draft EIR, the project footprint was refined to reduce the total number of turbines from 60 to 47	

MITIGATION MEASURES SUGGESTED IN COMMENTS TO DEIR AND RESPONSES

Ref	Comment	Response	MM
    O1-4 O5B-44 O16-6	all or a portion of the nesting season is a potentially feasible mitigation measure to minimize murrelet collisions with turbines. Full curtailment during the breeding season (during all hours of the day and night) should be mandatory for all sites in Marbled Murrelets territory. Wind turbine curtailment should be conducted throughout the MAMU breeding season (not just in the morning), as has been proposed by wildlife agencies as required for adequate MAMU mitigation for other wind project impacts in the similar scenarios (within and between foraging and nesting habitat).	and to eliminate turbines from the areas of the project with the highest marbled murrelet passage rates. This layout reduces the risk to marbled murrelets because it eliminates their exposure to collision with the highest risk turbines. The corvid management program, in contrast, is projected to result in reproductive success for 48 to 97 murrelets over the life of the project, resulting in a net benefit to the species. Curtailment for marbled murrelet is addressed in Master Response 2 of the FEIR and was rejected as infeasible for the reasons stated above and because it is an unknown post-operational regime that would render the project unfinanceable and infeasible.	
S4-6 O1-5 O5B-44	(Relative to Marbled Murrelets) …Additionally, habitat acquisition and preservation in perpetuity via conservation easements or other instruments may be a feasible mitigation measure that should be considered in the DEIR. There is no mitigation for acquiring additional habitat to provide greater protection for the species. Include offsite compensatory mitigation in the form of land purchase and protection.	Off-site compensatory mitigation may not be necessary to offset project-related operational impacts on marbled murrelet because the proposed predator management efforts at Van Duzen County Park are anticipated to result in a level of compensation that exceeds the extent of the predicted take over the life cycle of the proposed project, thus in essence “overcompensating” for the anticipated take. However, in the unlikely event that impacts to murrelets far exceed model predictions, or if the proposed mitigation strategy fails for unforeseen reasons, other feasible options as outlined in the DEIR will remain under consideration as an adaptive backup plan and will remain part of the Mitigation and Monitoring Program (MMRP) to be adopted at the time of project approval and EIR certification.	3.5-2c
S5-5	(Relative to Marbled Murrelets) Did the County consider real-time monitoring and/or adaptive management measure to reduce the potential for collisions? Projects in other parts of the US have included radar based monitoring or other technologies to detect in real-time the presence of sensitive bird species. Once a sensitive species is detected, wind farm	See Response to S4-6 above.	

Ref	Comment	Response	MM
	managers can use this information to selectively shutoff turbines that could be in the flight path of the bird, thus minimizing the likelihood of collision. Would a similar program be feasible and effective for the proposed project?		
O5-10	Develop stronger erosion control measures than silt fencing. Include clear metrics for revegetation of cleared areas, including timelines and publicly involved adaptive management,	The project applicant will prepare a Stormwater Pollution Prevention Plan and implement Best Management Practices to reduce potential adverse impacts to water quality and aquatic species. Implementation of the avoidance and minimization measures listed in Mitigation Measure 3.5-21a (Avoid and Minimize Impacts on Aquatic, Riparian, and Upland Habitats), Mitigation Measure 3.5-22a (Avoid and Minimize Impacts on Aquatic Resources)	3.5-21a 3.5-22a
O5-10	Prevent of the use of treated wastewater with phosphates for dust suppression	Regarding the request to avoid using treated wastewater with phosphates for dust suppression, the water used would need to meet all requirements for public safety. There is no indication that use of the treated wastewater for dust control would lead to adverse effects on aquatic resources.	
O5-10	Develop a Sacramento pikeminnow control plan prevent the invasive species from dominating the ecosystem	With respect to the request to develop a pikeminnow control plan, there are no activities associated with construction or operation of the project that would involve the introduction or spread of pikeminnow; therefore, there is no need to develop a control plan for this species.	
O5-12	The DEIR fails to adopt feasible mitigation measures, such as undergrounding of powerlines, or proposes ineffective and improperly deferred mitigation measures that do not mitigate Project impacts to a less than significant level.	Section 3.13, “Fire Protection Services and Wildfire Hazards,” of the DEIR provides information related to wildfire and Master Response 10, “Wildfire,” of this FEIR provides further discussion of the history of wildfire in the region and regulatory requirements and mitigation measures that reduce the potential for wildfires.	

MITIGATION MEASURES SUGGESTED IN COMMENTS TO DEIR AND RESPONSES

Ref	Comment	Response	MM
O5-18	Other mitigation measures that are feasible and have been required elsewhere to reduce NOx from construction equipment include: • Use alternative fueled equipment (e.g., propane), where available; • Limit engine idling to 2 minutes for delivery trucks and dump trucks; • Purchase offsets; • Employ a construction site manager to verify that engines are properly maintained and to maintain a log.	The information submitted by the commenter is noted. Section 3.4, "Air Quality," of the DEIR provides a thorough analysis of air quality impacts resulting from the proposed project and the proposed mitigation measures. The current mitigation requires use of current phase off-road construction vehicles and equipment (currently Tier 4 final.) This is established by the California Air Resources Board and set thresholds for emissions. The mitigation measure will be modified to include the feasible requirements that have been identified in this list.	3.4-1
O7-29	Please discuss whether it would be feasible to implement these measures at the Project site a. Establishing turbine no-build areas where there has been high eagle and other raptor use, movement corridors, and nesting and foraging habitats. b. An agreement to implement procedures for using explosives and conducting blasting activities within specified times and at specified distances from sensitive wildlife (including eagles). c. An agreement to curtail operation of any turbines that are located within 1 mile (1,600 meters) of unoccupied golden eagle nests during daylight hours between February 1 and April 30 while determining nest activity.	The mitigation measures suggested by the commenter are either already incorporated into the DEIR (procedures and buffers for blasting) and project layout (studies for eagle use across the project indicate no consistent high use area within the project footprint) or are not feasible (daytime curtailment).	
O12-4	These include, among other things: • proper siting of wind turbines to avoid impacts, • operational curtailments during high-risk periods, and • incorporation of deterrence technologies.	These comments are very general and it is not possible to determine which impact is being referred to. Micrositing of the turbines have been accomplished to avoid high passage areas for marbled murrelet, higher cut in speeds and some curtailment could be required for bats, and deterrence technology is being required for bats.	
O13-12	Curtailed energy production for birds and bats should be implemented once the turbines are in operation and not be	There are no Fully Protected bat species in the project area, the CEQA criteria is an impact that would result in a	

MITIGATION MEASURES SUGGESTED IN COMMENTS TO DEIR AND RESPONSES

Ref	Comment	Response	MM
	deferred while obtaining information on baseline mortality rates.	population level decline. Curtailment can be required if other mitigation (deterrents) proves unsuccessful.	
O13-13	Mitigation Measure 3.5-18b should include additional information on the mortality surveys, such as the definition of the search circumference. The search circumference should be a minimum of the rotor's circumference plus additional area searched to account for distance remains might be flung after contacting rotor tips moving 200 mph, and the distance that remains might be moved by scavenging wildlife.	As described in Mitigation Measure 3.5-18b, the bat Technical Advisory Committee will review the post-construction monitoring protocol and will provide the appropriate guidance for the most effective methods.	3.5-18b
O9-19	Compensatory Owl Mitigation Should Be Focused on High-Impact Areas. The county should work with the conservation community and owl experts to identify high-priority areas. High-priority areas for conservation are those that both are important to the survival and recovery of the northern spotted owl, inter alia designated critical habitat or occupied nesting/roosting habitat, and are at risk from development or timber production.	Mitigation Measure 3.5-7 was modified to specify that the mitigation land must be suitable habitat determined by the County in consultation with CDFW and USFWS. Land to be conserved as mitigation lands shall be of equal or higher value as the land disturbed. Mitigation lands shall contain at least one drainage, be of lower slopes compared to project area lands, and shall provide suitable foraging, nesting and roosting habitat in similar ratios to the lands being disturbed. Preference shall be given to lands suitable for nesting, roosting and foraging activities in that order.	3.5-7
O9-20	Barred Owl Management Encouraged	Mitigation Measure 3.5-7 was refined to give the applicant the option of including a barred owl management plan in addition to acquisition or conservation easements of northern spotted owl migration lands.	3.5-7
O9-24	The DEIR considers impacts to raptors to be significant and unavoidable. However, the DEIR has failed to exhaust all meaningful and feasible potential mitigation measures. At other wind projects, camera-based automatic bird detection systems (such as IdentiFlight) have been paired with operational curtailment to reduce impacts to species. The Top of the World Windpower Project utilizes 24 IdentiFlight units to	Use of this technology is still experimental • There are false negatives (8% of eagles missed) but false positives are more common (28% of "eagle" were not eagles) (McClure et al., 2018), • The units are mounted on towers 7-10 m tall, which will significantly limit their ability to visualize eagles in portions of the Humboldt project that are forested,	

MITIGATION MEASURES SUGGESTED IN COMMENTS TO DEIR AND RESPONSES

Ref	Comment	Response	MM
I43-1 I114-1	recognize when certain species enter the project area and can trigger "informed curtailment" of individual wind turbines. Can every possible mitigation effort please be considered? Here is a recent article of interest, regarding one cutting edge tool - Artificial Intelligence to shut down turbines at winged approach:	• The mountainous terrain of the project area will likely limit each units' view that much more, which may further increase the number of units needed, rocketing the cost of a full system even higher, and • Units work in the light of day and with good visibility; therefore, would not be reliable in fog conditions.	
O9-26	Mitigation by curtailment is clearly an option, but the DEIR includes no discussion or evaluation of curtailment for murrelets. In contrast to the uncertain benefit of predator management, curtailment has high certainty: the project has good data on murrelet risk periods and curtailment is effective—murrelets will not be killed by non-rotating, curtailed turbine blades. For the previously proposed Shell Wind project on Bear River Ridge, turbine curtailment was evaluated by the project proponents as a means to minimize murrelet impacts (Golightly3 and Schneider 2009); they evaluated turbine curtailment for 2 hours during the early morning flight period, for a range of about 90 to about 140 days during the breeding season. A similar evaluation is appropriate and feasible as part of the impact assessment and mitigation for this project.	Master Response 2 addresses curtailment for Marbled Murrelet.	
O9-27	The project should consider and evaluate other mitigation actions. For example, the U.S. Fish and Wildlife Service has identified 11 conservation needs for the murrelet, USFWS (2011), of which the following might be appropriate for the project: Short-term conservation actions: 1. Maintain potential and suitable habitat in large contiguous blocks; 2. maintain and enhance buffer habitat surrounding occupied habitat; and 3. decrease adult and juvenile mortality [reducing juvenile mortality is proposed].	The applicant initially considered several long-term projects that could ultimately have added new nesting habitat or added protections to existing habitat. However, these projects would require development time well beyond the project (100+ years to effect, time to grow trees, etc.) and could not be considered compensatory within the same timeframe as the project. Consequently, these kinds of projects did not garner agency support to meet the compensatory mitigation requirement.	

MITIGATION MEASURES SUGGESTED IN COMMENTS TO DEIR AND RESPONSES

Ref	Comment	Response	MM
	Long-term conservation actions: 8. Protect "recruitment" nesting habitat to buffer and enlarge existing stands, reduce fragmentation, and provide replacement habitat for current suitable nesting habitat lost to disturbance events; and 9. speed up development of new habitat.		
O9-27	Finally, the project should evaluate closure or relocation of campgrounds and/or picnic areas (focal areas for human food sources for corvids) within murrelet nesting habitat to other locations to reduce predation risk. This action has long been recognized as a conservation priority, but implementation has many political and societal challenges.	Closure or relocation of campgrounds and/or picnic areas (focal areas for human food sources for corvids) within murrelet nesting habitat to other locations to reduce predation risk, was pursued by the project applicant, however, managing agencies for the campgrounds and picnic areas did not support that approach, therefore that potential mitigation was found to be infeasible.	
I119-1)?I114-1 I170-30	This one is a sonic technique to help bats avoid the blades: http://www.anthropocenemagazine.org/2019/05/whistling-wind-turbines-warn-bats/?utm_source=Anthropocene&utm_campaign=f213a7ef23-Anthropocene+science+to+AM&utm_medium=email&utm_term=0_ececcea89a-f213a7ef23-294296189 "For example, ultraviolet visual and ultrasonic acoustic bat deterrent systems offer promising potential to reduce bat collisions with WTGs (Szewczak and Arnett 2008; Arnett et al. 2013; Hein 2018; NRG 2018). Over the life of the project, such approaches in development may be found appropriate for use with the proposed project."	Deterrence technology is part of the mitigation required for bats.	3.5-19d
I119-1	I've seen report that say the bladeless turbines work more effectively than old turbines, but you should research them yourself. Thanks for all of your hard work. Here's a link I found real quickly for you to start.	The reference report identifies that the bladeless turbines are less efficient.	

MITIGATION MEASURES SUGGESTED IN COMMENTS TO DEIR AND RESPONSES

Ref	Comment	Response	MM
	https://www.evwind.es/2019/05/31/bladeless-wind-turbines-less-efficient-in-the-conversion-ofcaptured-wind-power-into-electrical-energy/67462		
	“	See mitigation measure 3.5-18d.	

Attachment 2

To: John Ford, Director, Humboldt County Planning & Building Department

From: Economic & Planning Systems, Inc.

Subject: Financial Feasibility Analysis of Proposed Humboldt Wind Energy Project; EPS #191085

Date: November 11, 2019

Humboldt Wind LLC has proposed a 47-turbine wind energy project in Humboldt County. In a previous memorandum, Economic & Planning Systems, Inc. (EPS) evaluated the development feasibility of three Environmental Impact Report (EIR) alternatives under a range of potential pricing conditions.[1] This memorandum conducts a corresponding feasibility analysis of the proposed 47-turbine project using the same methodology and potential pricing conditions.

To assess development feasibility, EPS prepared development cashflow pro formas for the Proposed Project under three separate pricing scenarios. The rates of return were compared to the identified hurdle after-tax internal rate of return (IRR) of 7.5 percent, as well as the IRRs of the EIR alternatives evaluated in the prior analysis.

This hurdle rate of return was set by considering the weighted average cost of capital for these types of investments, a level that the expected after-tax rate of return would need to meet for a project to move forward. For California utilities, the "return on original cost" provided in recent utility rate cases provides a proxy for the cost of capital and indicated returns of between 7.34 percent and 7.69 percent.[2] In addition, using a standard Capital Asset Pricing Model (CAPM) model, Terra Gen has indicated that its weighted cost of capital is about 7.5 percent.

This memorandum is divided into two main sections. The first provides the summary of findings and the second describes the feasibility analysis, including cost and revenue assumptions and the estimated rates of return for the Proposed Project.

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[1] See "Humboldt Wind Energy Project EIR Alternatives Financial Feasibility Analysis", October 22, 2019.

[2] Based on six (6) past rate cases in 2016/ 2017 with reported "return on original cost rate" for California utilities, including Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric. Pending 2018/ 2019 rates cases suggest potential increases in the returns for these cases.

Key Findings

The feasibility of the proposed 47-turbine project is uncertain and will depend on achieving revenues at the top end of the potential range.

As shown in **Table 1**, the Proposed Project is forecast to achieve after-tax Internal Rates of Return (IRRs) ranging from 5.3 percent to 7.55 percent under the range of PPA pricing evaluated. With a hurdle rate of return of 7.5 percent, only the higher PPA pricing scenario would meet or exceed this hurdle rate. Under the lower pricing scenario, the Proposed Project would not be feasible and under the mid-level pricing, the expected IRR would still be a percentage point below the hurdle level.

The Proposed Project would result in higher returns than all the EIR alternatives evaluated.

As shown in **Table 1**, the Proposed Project generates higher after-tax IRRs than the EIR Alternatives under all pricing scenarios. These differences are driven by the relative scales of the alternatives evaluated and the higher number of wind turbines under the Proposed Project. As noted in the prior memorandum, the EIR Alternatives indicate IRRs of well below the hurdle rate under all pricing scenarios.

Table 1. Internal Rates of Return for Proposed Project and Alternatives [3]

Alternative	Number of Turbines	Megawatts Generated	After-Tax IRR (1)		
			Low PPA	Mid PPA	High PPA
Proposed Project	47	147	5.30%	6.47%	7.55%
Alternative 3	23	72	2.75%	3.88%	4.90%
Alternative 4	31	97	3.95%	5.09%	6.14%
Alternative 5	27	84	3.42%	4.56%	5.59%

(1) Low, Mid, and High PPA pricing reflects $45, $50, and $55 per megawatt hour respectively.

[3] The project applicant has informed the County that Alternative 5 needs to be revised from 37 turbines to 27 because that is the maximum number that can be physically accommodated on Monument Ridge. Please see the Master Response on Alternatives in the Final EIR for a more detailed explanation of why wake effect, interference with existing microwave beam paths, and the steepness of the terrain would preclude placement of more than 27 turbines on Monument Ridge.

Financial Feasibility Analysis

The project proponent, working with EPS, provided key financial (cost and revenue) estimates developed for the Proposed Project (47 wind turbines and 147 MW capacity) that included estimates of all cost categories and revenue categories. EPS reviewed these financial estimates, considered them reasonable, and used them to inform standard pro forma cashflow analyses for the proposed project (and the three identified alternatives).[4] Because production tax credits and the accelerated depreciation and associated tax benefits provided to wind energy projects are key components of supporting the viability of these projects, these financial characteristics are incorporated into the financial analyses, and an unlevered, after-tax internal rate of return (IRR) was calculated.

The after-tax IRR was derived for the proposed project (and the three alternatives) and these IRRs were then compared to the hurdle rate to provide a planning-level indication of development feasibility. The financial analysis of the Proposed Project, including cost and revenue assumptions and development pro forma outcomes, are described below. **Table 2** provides the underlying revenue and cost assumptions and **Tables 3** through **5** provide the detailed pro forma cash flow analyses for the proposed 47-turbine project under the Low-, Mid-, and High-Point PPA pricing scenarios. The detailed analyses for the alternatives are included in the prior October 22, 2019 memorandum.

Key Financial Assumptions

Table 2 summarizes the key financial assumptions developed by Terra-Gen and EPS for the proposed project.

Key assumptions include.

- **Energy Production.** The wind turbines are expected to have a gross generation capacity of about 3.13 MW (mega-watts) per turbine. Consistent with other wind energy projects, the net production is substantially lower at 40 percent of gross capacity, an equivalent of 1.25 MW per turbine or 10,977 MWH (mega-watt hours) per turbine annually.
- **Revenues.** Wind energy sales revenues depend on annual energy production and the energy sales price. Level Ten Energy's PPA (power purchase agreement) Price Index Report for the third quarter of 2019 indicates a current PPA pricing of $50.80 per MWH for the Northern California region. This is rounded down to $50 per MWH for the purposes of the baseline Mid-point PPA pricing scenario. Additional sensitivity analyses are conducted at PPA pricing of $45 per MWH and $55 per MWH. The pricing is assumed to be fixed under the PPA for the first 15 years of operation. Thereafter, energy will be sold on the merchant/ wholesale market where prices are expected to increase at the pace of inflation from year 16 onwards. Production tax credit revenues are also a key part of the wind energy project profile. The current IRS-approved wind energy production tax credit rate is $25 per MWH, which is expected to increase to about $27 per MWH by the time the project starts producing energy.

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[4] EPS reviewed a number of studies in considering the data provided by project proponent including: USDOE, Office of Energy Efficiency and Renewable Energy, and National Renewable Energy Laboratory (NREL) publications.

Table 2. Financial Estimates for Proposed Project (47 Turbines) and Per Turbine Multipliers

Item	Proposed Project	Notes	Per Turbine
Energy Production			
Gross Production	147	MW	3.13 MW
minus	50%	Gross Capacity Factor	
minus	10%	Additional Loss Factor	
Net Production	40%	of Gross Production	1.25 MW
Annual Net Energy Production	8,766	Average Hours per Year	10,967 MWH
Revenues			
Low PPA Energy Price per MWH (1st 15 Years)	$45.00	per MWH	
Mid PPA Energy Price per MWH (1st 15 Years)	$50.00	per MWH	
High PPA Energy Price per MWH (1st 15 Years)	$55.00	per MWH	
Merchant Energy Price per MWH (16+ Years)	Escalated by inflation after Year 16		
Tax Credit Revenue per MWH/ Credit	$27.00	per MWH	
Project Development Costs			
5 Year MACRS Fixed	$19,089,600		Fixed
5 Year MACRS Variable	$161,289,408		$3,431,690
12 Year Straight Line Fixed/Variable (1)	$94,518,600		Fixed/Variable
15 Year MACRS Fixed	$33,254,000		Fixed
Total Project Development Costs	$308,151,608		$6,556,417
Annual Operating Costs			
General & Administrative (G&A)			
Land Leases	10.5%	of Revenues	N/A
PTAX	$2,100,000	Variable	$44,681
Insurance	$760,000	Variable	$16,170
Other G&A	$530,000	Fixed	N/A
Subtotal G&A	$3,390,000		$72,128
Operating & Maintenance (O&M)			
Turbine Maintenance	$2,800,000	Variable	$59,574
Non-Turbine Maintenance	$780,000	Variable	$16,596
Subtotal O&M	$3,580,000		$76,170
Additional Assumptions			
General Rate of Inflation	2.5%		
Add'l Turbine Maintenance Inflation	1.0%		
Federal Corporate Tax Rate	21%		

(1) Costs depreciated by 12 Year Straight Line method represent 52.4% of the combined 5 Year MACRS fixed and variable costs.

Source: Terra-Gen

- **Project Development Costs.** The development of a wind energy project includes a broad range of upfront investments. Some of these investments/ costs will be fixed independent of the alternative selected, while others will vary with the number of wind turbines. As shown in **Table 2**, Terra-Gen estimated the total project development cost of the proposed project at about $308 million. These costs are distinguished by applicable depreciation schedules which vary by type of cost, with certain wind energy development costs eligible for the accelerated 5-year depreciation (MACRS) schedule that provides important tax benefits to support wind energy project feasibility.

- **Annual Operating Costs.** Annual operating costs include two main categories, general and administrative costs and operating and maintenance costs. General and administrative costs include land lease payments, property tax payments, insurance, and other general administrative costs. As shown in **Table 2**, land lease costs are tied to energy sales revenues, property taxes vary by alternative though do not inflate over time, insurance costs vary by alternative and increase annually by inflation, and other costs are fixed for all alternatives and increase by inflation annually. Operating and maintenance costs include turbine maintenance costs and non-turbine (balance of plant) maintenance costs. Both cost items are variable on a per turbine basis. The non-turbine costs are increased annually by the assumed rate of general inflation (2.5 percent), while the turbine operating costs are assumed to increase annually by 3.5 percent (this represents the base inflation level of 2.5 percent and an additional 1.0 percent to account for the mechanical nature of the turbines and the need for higher levels of maintenance expenditures to limit the loss of wind energy productivity over life of the turbines).

- **Additional Assumptions**. The additional assumptions shown in **Table 2** include the general rate of inflation used to escalate costs annually where appropriate in the time-series pro forma analyses for each alternative and an additional rate of cost increase for turbine maintenance for reasons described above. The federal corporate tax rate of 21 percent is also noted and, as described below, is applied in the pro forma analyses to help determine the tax benefits associated with the allowed depreciation schedules.

Pro Forma Cashflow Analyses and Results

Tables 3, **4**, and **5** show annual pro forma cashflow analyses for the Proposed Project under the Low-, Mid-, and High-PPA pricing scenarios. All the analyses follow the same structure, combining the specified number of turbines and associated energy production with the key assumptions described in **Table 2** to calculate each scenario's net income after tax and the associated after-tax IRR. Key components and results of the pro forma analyses are described below:

- **Duration.** The pro forma analyses are run for a 25-year operating period. This is close to the useful life of wind turbines and provides a substantial time period for analysis. For the purposes of this analysis, it is assumed that decommissioning costs balance with any end-of-period project value. Because the PPA will last 15 years, pricing for the first 15 years is fixed and then adjusted by annual inflation to approximate potential wholesale/ merchant pricing.

- **Energy Production.** Energy production is directly tied to the number of wind turbines and, for analytical simplicity, is assumed to be consistent each year. Annual energy production is assumed to remain consistent at 515,441 MWH per year under the proposed project.

- **Energy Sales Revenue.** Energy sales revenue is tied to energy production and varies by the PPA price used in the pro forma analyses. The PPA price is the only variable input within **Tables 3, 4,** and **5**, varying from $45 to $55 per MWH. PPA Pricing is used only for the first fifteen years, after which the sales revenue is determined by potential wholesale/ merchant pricing as previously mentioned.

- **Operating Costs.** Operating costs are mostly variable with the number of turbines. For the Proposed Project with 47 turbines, operating costs remain stable, though operating costs as a percent of revenues change based due to variations in PPA prices/ revenues.

- **Total Project Development Costs.** Of the $308 million in total development costs for the Proposed Project (about $6.6 million per wind turbine), about $62.3 million are assumed to be fixed costs.

- **Earnings**. The pro forma analyses calculate the earnings/ EBITDA, which represents the earnings before taxes, depreciation, and amortization. Earnings are calculated by subtracting operating costs and project development costs from revenues. As shown in **Tables 3**, **4**, and **5**, the earnings all start substantially negative due to the upfront project development costs and are then positive for the duration of the analysis. Total net earnings (nominal and undiscounted range) increase substantially along with the increases in PPA prices evaluated.

- **Additional Revenues/ Tax Benefits.** For wind energy projects, the additional revenues from production tax credits and the tax benefits associated with an accelerated depreciation schedule are key to improving overall returns and increasing the number of viable projects, including:

  \- **Production Tax Credits**. Wind energy projects receive production tax credits on a per-kilowatt-hour (KWH) basis in an amount adjusted by the IRS annually. In 2019, the rate is set at $0.025 per-KWH, which equates to $25 per MWH. Terra-Gen forecasts that this rate will increase to $27 per MWH when energy production begins. The production tax credits apply for the first ten (10) years of project operation. This rate is applied to energy production and is escalated annually by the rate of inflation.

  \- **Depreciation/ Tax Benefits**. Renewable energy projects can depreciate some of their costs at a pace faster than typically allowed, bringing forward some of the benefits of depreciation. As shown in the cash flow analyses, a substantial proportion of project development costs (some fixed and some variable) can be depreciated under the accelerated 5-year MACRS schedule, established by the IRS and provided by Terra-Gen. When the depreciation schedule is combined with earnings to determine taxable income and the current federal corporate tax rate is applied, the potential tax savings/ costs each year are established. For all scenarios, though to different degrees, the first five years result in tax savings, meaning that the project owner can use the negative taxable income to offset tax obligations from other ventures.

  \- **Net Income after Tax**. The annual cashflow of net income after tax equals the sum of the earnings, tax benefits/ costs, and production tax credits. From this after-tax net income stream, the after-tax IRR can be calculated, a barometer for project feasibility when compared to the hurdle rate of return. As shown, the after-tax IRRs for the Proposed Project range from 5.30 percent (under the Low-PPA), to 6.47 percent (under the Mid-PPA), to 7.55 percent (under the High-PPA).

Table 3
Humboldt Wind Energy Project Financial Analysis - Proposed Project (Low PPA Pricing)
Turbines: 47
MW: 147

Item		Total	0	1	2	3	4	5	6	7	8	9	10	11	12
OVERAL PROJECT ECONOMICS															
Energy Production															
Annual Net Energy Production (mWh)			0	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441
Energy Sales Revenue															
PPA revenue		$347,922,540	$0	$23,194,836	$23,194,836	$23,194,836	$23,194,836	$23,194,836	$23,194,836	$23,194,836	$23,194,836	$23,194,836	$23,194,836	$23,194,836	$23,194,836
Merchant Revenue		$266,357,118	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual Revenues		**$614,279,658**	**$0**	**$23,194,836**	**$23,194,836**	**$23,194,836**	**$23,194,836**	**$23,194,836**	**$23,194,836**	**$23,194,836**	**$23,194,836**	**$23,194,836**	**$23,194,836**	**$23,194,836**	**$23,194,836**
Annual Operating Costs															
General & Administrative (G&A)															
Land Leases		$64,499,364	$0	$2,435,458	$2,435,458	$2,435,458	$2,435,458	$2,435,458	$2,435,458	$2,435,458	$2,435,458	$2,435,458	$2,435,458	$2,435,458	$2,435,458
PTAX		$52,500,000	$0	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000
Insurance		$25,959,901	$0	$760,000	$779,000	$798,475	$818,437	$838,898	$859,870	$881,367	$903,401	$925,986	$949,136	$972,864	$997,186
Other G&A		$18,103,615	$0	$530,000	$543,250	$556,831	$570,752	$585,021	$599,646	$614,638	$630,003	$645,754	$661,897	$678,445	$695,406
Subtotal G&A		$161,062,880	$0	$5,825,458	$5,857,708	$5,890,764	$5,924,647	$5,959,376	$5,994,974	$6,031,462	$6,068,862	$6,107,198	$6,146,491	$6,186,767	$6,228,050
Operating & Maintenance (O&M)															
Turbine Maintenance		$109,059,599	$0	$2,800,000	$2,898,000	$2,999,430	$3,104,410	$3,213,064	$3,325,522	$3,441,915	$3,562,382	$3,687,065	$3,816,113	$3,949,677	$4,087,915
Non-Turbine Maintenance		$26,643,056	$0	$780,000	$799,500	$819,488	$839,975	$860,974	$882,498	$904,561	$927,175	$950,354	$974,113	$998,466	$1,023,428
Subtotal O&M		$135,702,655	$0	$3,580,000	$3,697,500	$3,818,918	$3,944,385	$4,074,038	$4,208,020	$4,346,476	$4,489,557	$4,637,420	$4,790,226	$4,948,142	$5,111,343
Total Operating Costs		**$296,765,534**	**$0**	**$9,405,458**	**$9,555,208**	**$9,709,682**	**$9,869,031**	**$10,033,415**	**$10,202,994**	**$10,377,938**	**$10,558,419**	**$10,744,617**	**$10,936,717**	**$11,134,909**	**$11,339,392**
	48.3% of annual revenues														
Project Development Costs															
5 Year MACRS Fixed		$19,089,600	$19,089,600												
5 Year MACRS Variable		$161,289,408	$161,289,408												
12 Year Straight Line Fixed/Variable		$94,518,600	$94,518,600												
15 Year MACRS Fixed		$33,254,000	$33,254,000												
Total Development Costs		**$308,151,608**	**$308,151,608**												
Total Development Cost per Turbine		$6,556,417													
Earnings (EBITDA) (1)		**$9,362,515**	**($308,151,608)**	**$13,789,378**	**$13,639,628**	**$13,485,154**	**$13,325,805**	**$13,161,421**	**$12,991,842**	**$12,816,898**	**$12,636,417**	**$12,450,219**	**$12,258,119**	**$12,059,927**	**$11,855,444**
Depreciation				**($83,328,192)**	**($54,145,068)**	**($36,535,441)**	**($29,783,182)**	**($29,523,856)**	**($9,840,165)**	**($9,840,165)**	**($9,840,165)**	**($9,840,165)**	**($9,840,165)**	**($9,840,165)**	**($9,183,786)**
5 Years MACRS (2)				40%	24%	14%	11%	11%							
12 Years SL (2)				8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
15 Year MACRS (2)				10%	9%	8%	7%	7%	6%	6%	6%	6%	6%	6%	6%
Taxable Income				**($69,538,813)**	**($40,505,440)**	**($23,050,287)**	**($16,457,377)**	**($16,362,435)**	**$3,151,676**	**$2,976,732**	**$2,796,251**	**$2,610,053**	**$2,417,954**	**$2,219,761**	**$2,671,657**
Tax Benefits/ Costs (3)	**21%**	**($2,117,738)**		**$14,603,151**	**$8,506,142**	**$4,840,560**	**$3,456,049**	**$3,436,111**	**($661,852)**	**($625,114)**	**($587,213)**	**($548,111)**	**($507,770)**	**($466,150)**	**($561,048)**
Energy Credit Revenues		**$155,916,362**		**$13,916,902**	**$14,264,824**	**$14,621,445**	**$14,986,981**	**$15,361,655**	**$15,745,697**	**$16,139,339**	**$16,542,823**	**$16,956,393**	**$17,380,303**		
Net Income After Tax (4)		**$163,161,139**	**($308,151,608)**	**$42,309,431**	**$36,410,595**	**$32,947,159**	**$31,768,835**	**$31,959,188**	**$28,075,686**	**$28,331,123**	**$28,592,027**	**$28,858,501**	**$29,130,652**	**$11,593,777**	**$11,294,396**
Unlevered After Tax IRR	**5.30%**														

Item	13	14	15	16	17	18	19	20	21	22	23	24	25
OVERAL PROJECT ECONOMICS													
Energy Production													
Annual Net Energy Production (mWh)	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441
Energy Sales Revenue													
PPA revenue	$23,194,836	$23,194,836	$23,194,836	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Merchant Revenue	$0	$0	$0	$23,774,707	$24,369,075	$24,978,301	$25,602,759	$26,242,828	$26,898,899	$27,571,371	$28,260,655	$28,967,172	$29,691,351
Annual Revenues	**$23,194,836**	**$23,194,836**	**$23,194,836**	**$23,774,707**	**$24,369,075**	**$24,978,301**	**$25,602,759**	**$26,242,828**	**$26,898,899**	**$27,571,371**	**$28,260,655**	**$28,967,172**	**$29,691,351**
Annual Operating Costs													
General & Administrative (G&A)													
Land Leases	$2,435,458	$2,435,458	$2,435,458	$2,496,344	$2,558,753	$2,622,722	$2,688,290	$2,755,497	$2,824,384	$2,894,994	$2,967,369	$3,041,553	$3,117,592
PTAX	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000
Insurance	$1,022,116	$1,047,668	$1,073,860	$1,100,707	$1,128,224	$1,156,430	$1,185,341	$1,214,974	$1,245,348	$1,276,482	$1,308,394	$1,341,104	$1,374,632
Other G&A	$712,791	$730,611	$748,876	$767,598	$786,788	$806,458	$826,619	$847,285	$868,467	$890,178	$912,433	$935,244	$958,625
Subtotal G&A	$6,270,364	$6,313,737	$6,358,194	$6,464,649	$6,573,765	$6,685,609	$6,800,249	$6,917,756	$7,038,200	$7,161,655	$7,288,196	$7,417,901	$7,550,848
Operating & Maintenance (O&M)													
Turbine Maintenance	$4,230,992	$4,379,077	$4,532,345	$4,690,977	$4,855,161	$5,025,092	$5,200,970	$5,383,004	$5,571,409	$5,766,408	$5,968,232	$6,177,121	$6,393,320
Non-Turbine Maintenance	$1,049,013	$1,075,239	$1,102,120	$1,129,673	$1,157,914	$1,186,862	$1,216,534	$1,246,947	$1,278,121	$1,310,074	$1,342,826	$1,376,396	$1,410,806
Subtotal O&M	$5,280,006	$5,454,316	$5,634,464	$5,820,649	$6,013,075	$6,211,954	$6,417,504	$6,629,951	$6,849,530	$7,076,482	$7,311,058	$7,553,517	$7,804,126
Total Operating Costs	**$11,550,370**	**$11,768,053**	**$11,992,658**	**$12,285,298**	**$12,586,840**	**$12,897,563**	**$13,217,753**	**$13,547,707**	**$13,887,729**	**$14,238,137**	**$14,599,254**	**$14,971,418**	**$15,354,974**
Earnings (EBITDA) (1)	**$11,644,466**	**$11,426,783**	**$11,202,178**	**$11,489,409**	**$11,782,234**	**$12,080,738**	**$12,385,006**	**$12,695,121**	**$13,011,169**	**$13,333,235**	**$13,661,401**	**$13,995,754**	**$14,336,377**
Depreciation	**($1,963,615)**	**($1,963,615)**	**($1,961,910)**										
15 Year MACRS (2)	6%	6%	6%										
Taxable Income	**$9,680,851**	**$9,463,168**	**$9,240,268**	**$11,489,409**	**$11,782,234**	**$12,080,738**	**$12,385,006**	**$12,695,121**	**$13,011,169**	**$13,333,235**	**$13,661,401**	**$13,995,754**	**$14,336,377**
Tax Benefits/ Costs (3)	**($2,032,979)**	**($1,987,265)**	**($1,940,456)**	**($2,412,776)**	**($2,474,269)**	**($2,536,955)**	**($2,600,851)**	**($2,665,976)**	**($2,732,346)**	**($2,799,979)**	**($2,868,894)**	**($2,939,108)**	**($3,010,639)**
Net Income After Tax (4)	**$9,611,487**	**$9,439,518**	**$9,261,721**	**$9,076,633**	**$9,307,965**	**$9,543,783**	**$9,784,155**	**$10,029,146**	**$10,278,824**	**$10,533,255**	**$10,792,507**	**$11,056,646**	**$11,325,738**

(1) EBITDA = Earnings before taxes, depreciation, and amortization. Total Revenues minus Operating Costs minus Project Development Costs.
(2) IRS-established depreciation rates.
(3) Potential tax benefits/ costs equal federal corporate tax multiplied by taxable income. When postive, the owner of the wind farm can offset other tax liabilities, thereby obtaining a positive tax benefit.
(4) Net After Tax Income = Earnings (EBITA) plus Tax Savings plus Energy Credit Revenues.

Sources: Terra-Gen; Economic & Planning Systems, Inc.

Table 4
Humboldt Wind Energy Project Financial Analysis - Proposed Project (Mid PPA Pricing)
Turbines: 47
MW: 147

Item		Total	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
OVERAL PROJECT ECONOMICS																												
Energy Production																												
Annual Net Energy Production (mWh)			0	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441
Energy Sales Revenue																												
PPA revenue		$386,580,600	$0	$25,772,040	$25,772,040	$25,772,040	$25,772,040	$25,772,040	$25,772,040	$25,772,040	$25,772,040	$25,772,040	$25,772,040	$25,772,040	$25,772,040	$25,772,040	$25,772,040	$25,772,040	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Merchant Revenue		$295,952,353	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$26,416,341	$27,076,750	$27,753,668	$28,447,510	$29,158,698	$29,887,665	$30,634,857	$31,400,728	$32,185,746	$32,990,390
Annual Revenues		**$682,532,953**	**$0**	**$25,772,040**	**$25,772,040**	**$25,772,040**	**$25,772,040**	**$25,772,040**	**$25,772,040**	**$25,772,040**	**$25,772,040**	**$25,772,040**	**$25,772,040**	**$25,772,040**	**$25,772,040**	**$25,772,040**	**$25,772,040**	**$25,772,040**	**$26,416,341**	**$27,076,750**	**$27,753,668**	**$28,447,510**	**$29,158,698**	**$29,887,665**	**$30,634,857**	**$31,400,728**	**$32,185,746**	**$32,990,390**
Annual Operating Costs																												
General & Administrative (G&A)																												
Land Leases		$71,665,960	$0	$2,706,064	$2,706,064	$2,706,064	$2,706,064	$2,706,064	$2,706,064	$2,706,064	$2,706,064	$2,706,064	$2,706,064	$2,706,064	$2,706,064	$2,706,064	$2,706,064	$2,706,064	$2,773,716	$2,843,059	$2,914,135	$2,986,989	$3,061,663	$3,138,205	$3,216,660	$3,297,076	$3,379,503	$3,463,991
PTAX		$52,500,000	$0	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000
Insurance		$25,959,901	$0	$760,000	$779,000	$798,475	$818,437	$838,898	$859,870	$881,367	$903,401	$925,986	$949,136	$972,864	$997,186	$1,022,116	$1,047,668	$1,073,860	$1,100,707	$1,128,224	$1,156,430	$1,185,341	$1,214,974	$1,245,348	$1,276,482	$1,308,394	$1,341,104	$1,374,632
Other G&A		$18,103,615	$0	$530,000	$543,250	$556,831	$570,752	$585,021	$599,646	$614,638	$630,003	$645,754	$661,897	$678,445	$695,406	$712,791	$730,611	$748,876	$767,598	$786,788	$806,458	$826,619	$847,285	$868,467	$890,178	$912,433	$935,244	$958,625
Subtotal G&A		$168,229,476	$0	$6,096,064	$6,128,314	$6,161,370	$6,195,253	$6,229,983	$6,265,581	$6,302,069	$6,339,469	$6,377,804	$6,417,097	$6,457,373	$6,498,656	$6,540,971	$6,584,343	$6,628,800	$6,742,020	$6,858,071	$6,977,023	$7,098,948	$7,223,922	$7,352,020	$7,483,321	$7,617,904	$7,755,851	$7,897,247
Operating & Maintenance (O&M)																												
Turbine Maintenance		$109,059,599	$0	$2,800,000	$2,898,000	$2,999,430	$3,104,410	$3,213,064	$3,325,522	$3,441,915	$3,562,382	$3,687,065	$3,816,113	$3,949,677	$4,087,915	$4,230,992	$4,379,077	$4,532,345	$4,690,977	$4,855,161	$5,025,092	$5,200,970	$5,383,004	$5,571,409	$5,766,408	$5,968,232	$6,177,121	$6,393,320
Non-Turbine Maintenance		$26,643,056	$0	$780,000	$799,500	$819,488	$839,975	$860,974	$882,498	$904,561	$927,175	$950,354	$974,113	$998,466	$1,023,428	$1,049,013	$1,075,239	$1,102,120	$1,129,673	$1,157,914	$1,186,862	$1,216,534	$1,246,947	$1,278,121	$1,310,074	$1,342,826	$1,376,396	$1,410,806
Subtotal O&M		$135,702,655	$0	$3,580,000	$3,697,500	$3,818,918	$3,944,385	$4,074,038	$4,208,020	$4,346,476	$4,489,557	$4,637,420	$4,790,226	$4,948,142	$5,111,343	$5,280,006	$5,454,316	$5,634,464	$5,820,649	$6,013,075	$6,211,954	$6,417,504	$6,629,951	$6,849,530	$7,076,482	$7,311,058	$7,553,517	$7,804,126
Total Operating Costs		**$303,932,130**	**$0**	**$9,676,064**	**$9,825,814**	**$9,980,288**	**$10,139,638**	**$10,304,021**	**$10,473,601**	**$10,648,544**	**$10,829,026**	**$11,015,224**	**$11,207,323**	**$11,405,516**	**$11,609,999**	**$11,820,976**	**$12,038,659**	**$12,263,265**	**$12,562,670**	**$12,871,146**	**$13,188,977**	**$13,516,452**	**$13,853,873**	**$14,201,550**	**$14,559,803**	**$14,928,962**	**$15,309,368**	**$15,701,373**
	44.5%	of annual revenues																										
Project Development Costs																												
5 Year MACRS Fixed		$19,089,600	$19,089,600																									
5 Year MACRS Variable		$161,289,408	$161,289,408																									
12 Year Straight Line Fixed/Variable		$94,518,600	$94,518,600																									
15 Year MACRS Fixed		$33,254,000	$33,254,000																									
Total Development Costs		**$308,151,608**	**$308,151,608**																									
Total Development Cost per Turbine		$6,556,417																										
Earnings (EBITDA) (1)		**$70,449,215**	**($308,151,608)**	**$16,095,976**	**$15,946,226**	**$15,791,752**	**$15,632,402**	**$15,468,019**	**$15,298,439**	**$15,123,496**	**$14,943,014**	**$14,756,816**	**$14,564,717**	**$14,366,524**	**$14,162,041**	**$13,951,064**	**$13,733,381**	**$13,508,775**	**$13,853,671**	**$14,205,603**	**$14,564,692**	**$14,931,058**	**$15,304,825**	**$15,686,115**	**$16,075,054**	**$16,471,767**	**$16,876,378**	**$17,289,017**
Depreciation				**($83,328,192)**	**($54,145,068)**	**($36,535,441)**	**($29,783,182)**	**($29,523,856)**	**($9,840,165)**	**($9,840,165)**	**($9,840,165)**	**($9,840,165)**	**($9,840,165)**	**($9,840,165)**	**($9,183,786)**	**($1,963,615)**	**($1,963,615)**	**($1,961,910)**										
5 Years MACRS (2)				40%	24%	14%	11%	11%																				
12 Years SL (2)				8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%													
15 Year MACRS (2)				10%	9%	8%	7%	7%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%										
Taxable Income				**($67,232,216)**	**($38,198,843)**	**($20,743,689)**	**($14,150,780)**	**($14,055,837)**	**$5,458,274**	**$5,283,330**	**$5,102,849**	**$4,916,651**	**$4,724,551**	**$4,526,359**	**$4,978,255**	**$11,987,448**	**$11,769,766**	**$11,546,866**	**$13,853,671**	**$14,205,603**	**$14,564,692**	**$14,931,058**	**$15,304,825**	**$15,686,115**	**$16,075,054**	**$16,471,767**	**$16,876,378**	**$17,289,017**
Tax Benefits/ Costs (3)	**21%**	**($14,945,945)**		**$14,118,765**	**$8,021,757**	**$4,356,175**	**$2,971,664**	**$2,951,726**	**($1,146,237)**	**($1,109,499)**	**($1,071,598)**	**($1,032,497)**	**($992,156)**	**($950,535)**	**($1,045,434)**	**($2,517,364)**	**($2,471,651)**	**($2,424,842)**	**($2,909,271)**	**($2,983,177)**	**($3,058,585)**	**($3,135,522)**	**($3,214,013)**	**($3,294,084)**	**($3,375,761)**	**($3,459,071)**	**($3,544,039)**	**($3,630,693)**
Energy Credit Revenues		**$155,916,362**		**$13,916,902**	**$14,264,824**	**$14,621,445**	**$14,986,981**	**$15,361,655**	**$15,745,697**	**$16,139,339**	**$16,542,823**	**$16,956,393**	**$17,380,303**															
Net Income After Tax (4)		**$211,419,632**	**($308,151,608)**	**$44,131,643**	**$38,232,807**	**$34,769,371**	**$33,591,047**	**$33,781,400**	**$29,897,898**	**$30,153,335**	**$30,414,239**	**$30,680,713**	**$30,952,864**	**$13,415,989**	**$13,116,608**	**$11,433,700**	**$11,261,730**	**$11,083,934**	**$10,944,400**	**$11,222,427**	**$11,506,106**	**$11,795,536**	**$12,090,812**	**$12,392,031**	**$12,699,293**	**$13,012,696**	**$13,332,339**	**$13,658,323**
Unlevered After Tax IRR	**6.47%**																											

(1) EBITDA = Earnings before taxes, depreciation, and amortization. Total Revenues minus Operating Costs minus Project Development Costs.
(2) IRS-established depreciation rates.
(3) Potential tax benefits/ costs equal federal corporate tax multiplied by taxable income. When postive, the owner of the wind farm can offset other tax liabilities, thereby obtaining a positive tax benefit.
(4) Net After Tax Income = Earnings (EBITA) plus Tax Savings plus Energy Credit Revenues.

Sources: Terra-Gen; Economic & Planning Systems, Inc.

Table 5
Humboldt Wind Energy Project Financial Analysis - Proposed Project (High PPA Pricing)
Turbines: 47
MW: 147

Item		Total	0	1	2	3	4	5	6	7	8	9	10	11	12
OVERAL PROJECT ECONOMICS															
Energy Production															
Annual Net Energy Production (mWh)			0	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441
Energy Sales Revenue															
PPA revenue		$425,238,660	$0	$28,349,244	$28,349,244	$28,349,244	$28,349,244	$28,349,244	$28,349,244	$28,349,244	$28,349,244	$28,349,244	$28,349,244	$28,349,244	$28,349,244
Merchant Revenue		$325,547,588	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual Revenues		**$750,786,248**	**$0**	**$28,349,244**	**$28,349,244**	**$28,349,244**	**$28,349,244**	**$28,349,244**	**$28,349,244**	**$28,349,244**	**$28,349,244**	**$28,349,244**	**$28,349,244**	**$28,349,244**	**$28,349,244**
Annual Operating Costs															
General & Administrative (G&A)															
Land Leases		$78,832,556	$0	$2,976,671	$2,976,671	$2,976,671	$2,976,671	$2,976,671	$2,976,671	$2,976,671	$2,976,671	$2,976,671	$2,976,671	$2,976,671	$2,976,671
PTAX		$52,500,000	$0	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000
Insurance		$25,959,901	$0	$760,000	$779,000	$798,475	$818,437	$838,898	$859,870	$881,367	$903,401	$925,986	$949,136	$972,864	$997,186
Other G&A		$18,103,615	$0	$530,000	$543,250	$556,831	$570,752	$585,021	$599,646	$614,638	$630,003	$645,754	$661,897	$678,445	$695,406
Subtotal G&A		$175,396,072	$0	$6,366,671	$6,398,921	$6,431,977	$6,465,860	$6,500,589	$6,536,187	$6,572,675	$6,610,075	$6,648,410	$6,687,704	$6,727,980	$6,769,262
Operating & Maintenance (O&M)															
Turbine Maintenance		$109,059,599	$0	$2,800,000	$2,898,000	$2,999,430	$3,104,410	$3,213,064	$3,325,522	$3,441,915	$3,562,382	$3,687,065	$3,816,113	$3,949,677	$4,087,915
Non-Turbine Maintenance		$26,643,056	$0	$780,000	$799,500	$819,488	$839,975	$860,974	$882,498	$904,561	$927,175	$950,354	$974,113	$998,466	$1,023,428
Subtotal O&M		$135,702,655	$0	$3,580,000	$3,697,500	$3,818,918	$3,944,385	$4,074,038	$4,208,020	$4,346,476	$4,489,557	$4,637,420	$4,790,226	$4,948,142	$5,111,343
Total Operating Costs		**$311,098,726**	**$0**	**$9,946,671**	**$10,096,421**	**$10,250,894**	**$10,410,244**	**$10,574,628**	**$10,744,207**	**$10,919,151**	**$11,099,632**	**$11,285,830**	**$11,477,930**	**$11,676,122**	**$11,880,605**
	41.4%	of annual revenues													
Project Development Costs															
5 Year MACRS Fixed		$19,089,600	$19,089,600												
5 Year MACRS Variable		$161,289,408	$161,289,408												
12 Year Straight Line Fixed/Variable		$94,518,600	$94,518,600												
15 Year MACRS Fixed		$33,254,000	$33,254,000												
Total Development Costs		**$308,151,608**	**$308,151,608**												
Total Development Cost per Turbine		$6,556,417													
Earnings (EBITDA) (1)		**$131,535,914**	**($308,151,608)**	**$18,402,573**	**$18,252,823**	**$18,098,350**	**$17,939,000**	**$17,774,616**	**$17,605,037**	**$17,430,093**	**$17,249,612**	**$17,063,414**	**$16,871,314**	**$16,673,122**	**$16,468,639**
Depreciation				**($83,328,192)**	**($54,145,068)**	**($36,535,441)**	**($29,783,182)**	**($29,523,856)**	**($9,840,165)**	**($9,840,165)**	**($9,840,165)**	**($9,840,165)**	**($9,840,165)**	**($9,840,165)**	**($9,183,786)**
5 Years MACRS (2)				40%	24%	14%	11%	11%							
12 Years SL (2)				8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
15 Year MACRS (2)				10%	9%	8%	7%	7%	6%	6%	6%	6%	6%	6%	6%
Taxable Income				**($64,925,618)**	**($35,892,245)**	**($18,437,091)**	**($11,844,182)**	**($11,749,240)**	**$7,764,871**	**$7,589,928**	**$7,409,446**	**$7,223,249**	**$7,031,149**	**$6,832,956**	**$7,284,852**
Tax Benefits/ Costs (3)	**21%**	**($27,774,151)**		**$13,634,380**	**$7,537,371**	**$3,871,789**	**$2,487,278**	**$2,467,340**	**($1,630,623)**	**($1,593,885)**	**($1,555,984)**	**($1,516,882)**	**($1,476,541)**	**($1,434,921)**	**($1,529,819)**
Energy Credit Revenues		**$155,916,362**		**$13,916,902**	**$14,264,824**	**$14,621,445**	**$14,986,981**	**$15,361,655**	**$15,745,697**	**$16,139,339**	**$16,542,823**	**$16,956,393**	**$17,380,303**		
Net Income After Tax (4)		**$259,678,124**	**($308,151,608)**	**$45,953,855**	**$40,055,019**	**$36,591,584**	**$35,413,259**	**$35,603,612**	**$31,720,111**	**$31,975,547**	**$32,236,451**	**$32,502,925**	**$32,775,076**	**$15,238,201**	**$14,938,820**
Unlevered After Tax IRR	**7.55%**														

Item	13	14	15	16	17	18	19	20	21	22	23	24	25
OVERAL PROJECT ECONOMICS													
Energy Production													
Annual Net Energy Production (mWh)	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441	515,441
Energy Sales Revenue													
PPA revenue	$28,349,244	$28,349,244	$28,349,244	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Merchant Revenue	$0	$0	$0	$29,057,975	$29,784,424	$30,529,035	$31,292,261	$32,074,567	$32,876,432	$33,698,342	$34,540,801	$35,404,321	$36,289,429
Annual Revenues	**$28,349,244**	**$28,349,244**	**$28,349,244**	**$29,057,975**	**$29,784,424**	**$30,529,035**	**$31,292,261**	**$32,074,567**	**$32,876,432**	**$33,698,342**	**$34,540,801**	**$35,404,321**	**$36,289,429**
Annual Operating Costs													
General & Administrative (G&A)													
Land Leases	$2,976,671	$2,976,671	$2,976,671	$3,051,087	$3,127,365	$3,205,549	$3,285,687	$3,367,830	$3,452,025	$3,538,326	$3,626,784	$3,717,454	$3,810,390
PTAX	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000
Insurance	$1,022,116	$1,047,668	$1,073,860	$1,100,707	$1,128,224	$1,156,430	$1,185,341	$1,214,974	$1,245,348	$1,276,482	$1,308,394	$1,341,104	$1,374,632
Other G&A	$712,791	$730,611	$748,876	$767,598	$786,788	$806,458	$826,619	$847,285	$868,467	$890,178	$912,433	$935,244	$958,625
Subtotal G&A	$6,811,577	$6,854,950	$6,899,407	$7,019,392	$7,142,377	$7,268,436	$7,397,647	$7,530,088	$7,665,841	$7,804,987	$7,947,611	$8,093,801	$8,243,647
Operating & Maintenance (O&M)													
Turbine Maintenance	$4,230,992	$4,379,077	$4,532,345	$4,690,977	$4,855,161	$5,025,092	$5,200,970	$5,383,004	$5,571,409	$5,766,408	$5,968,232	$6,177,121	$6,393,320
Non-Turbine Maintenance	$1,049,013	$1,075,239	$1,102,120	$1,129,673	$1,157,914	$1,186,862	$1,216,534	$1,246,947	$1,278,121	$1,310,074	$1,342,826	$1,376,396	$1,410,806
Subtotal O&M	$5,280,006	$5,454,316	$5,634,464	$5,820,649	$6,013,075	$6,211,954	$6,417,504	$6,629,951	$6,849,530	$7,076,482	$7,311,058	$7,553,517	$7,804,126
Total Operating Costs	**$12,091,583**	**$12,309,265**	**$12,533,871**	**$12,840,041**	**$13,155,452**	**$13,480,390**	**$13,815,151**	**$14,160,039**	**$14,515,370**	**$14,881,469**	**$15,258,669**	**$15,647,318**	**$16,047,773**
Earnings (EBITDA) (1)	**$16,257,661**	**$16,039,979**	**$15,815,373**	**$16,217,934**	**$16,628,972**	**$17,048,645**	**$17,477,110**	**$17,914,528**	**$18,361,062**	**$18,816,874**	**$19,282,132**	**$19,757,003**	**$20,241,657**
Depreciation	**($1,963,615)**	**($1,963,615)**	**($1,961,910)**										
15 Year MACRS (2)	6%	6%	6%										
Taxable Income	**$14,294,046**	**$14,076,363**	**$13,853,463**	**$16,217,934**	**$16,628,972**	**$17,048,645**	**$17,477,110**	**$17,914,528**	**$18,361,062**	**$18,816,874**	**$19,282,132**	**$19,757,003**	**$20,241,657**
Tax Benefits/ Costs (3)	**($3,001,750)**	**($2,956,036)**	**($2,909,227)**	**($3,405,766)**	**($3,492,084)**	**($3,580,215)**	**($3,670,193)**	**($3,762,051)**	**($3,855,823)**	**($3,951,544)**	**($4,049,248)**	**($4,148,971)**	**($4,250,748)**
Net Income After Tax (4)	**$13,255,912**	**$13,083,942**	**$12,906,146**	**$12,812,168**	**$13,136,888**	**$13,468,430**	**$13,806,917**	**$14,152,477**	**$14,505,239**	**$14,865,330**	**$15,232,884**	**$15,608,032**	**$15,990,909**

(1) EBITDA = Earnings before taxes, depreciation, and amortization. Total Revenues minus Operating Costs minus Project Development Costs.
(2) IRS-established depreciation rates.
(3) Potential tax benefits/ costs equal federal corporate tax multiplied by taxable income. When postive, the owner of the wind farm can offset other tax liabilities, thereby obtaining a positive tax benefit.
(4) Net After Tax Income = Earnings (EBITA) plus Tax Savings plus Energy Credit Revenues.

Sources: Terra-Gen; Economic & Planning Systems, Inc.

Attachment 3

To: John Ford, Director, Humboldt County Planning & Building Department

From: Economic & Planning Systems, Inc.

Subject: Humboldt Wind Energy Project EIR Alternatives Financial Feasibility Analysis; EPS #191085

Date: October 22, 2019

Humboldt Wind LLC has proposed a 47-turbine wind energy project in Humboldt County. As part of the Environmental Impact Report (EIR) required under the California Environmental Quality Act (CEQA), a number of alternatives have been identified. Economic & Planning Systems, Inc. (EPS) has evaluated the financial feasibility of three project alternatives: the Reduced Turbine Footprint – Monument Ridge (Alternative 3), the Reduced Turbine Count (Alternative 4), and the Reduced Turbine Footprint – Bear River Ridge (Alternative 5). The purpose of this analysis is to assess the economic viability of the different wind turbine counts and configurations under current/ expected market, pricing, and cost conditions.

To assess development feasibility, EPS prepared development cashflow pro formas for these three project alternatives. These pro formas combined cost forecasts and revenue forecasts, including tax credit and depreciation benefits, to determine unlevered, after-tax internal rates of return (IRRs) for the proposed project and the alternatives. The rates of return were compared to the identified hurdle after-tax internal rate of return of 7.5 percent

This hurdle rate of return was set by considering the weighted average cost of capital for these types of investments, a level that the expected after-tax rate of return would need to meet for a project to move forward. For California utilities, the “return on original cost” provided in recent utility rate cases provides a proxy for the cost of capital and indicated returns of between 7.34 percent and 7.69 percent.[1] In addition, using a standard Capital Asset Pricing Model (CAPM) model, Terra Gen has indicated that its weighted cost of capital is about 7.5 percent. On that basis, a wind energy project would need to offer an after-tax IRR of more than 7.5 percent to be feasible. Projects offering lower IRRs will not attract prudent investors and thus are not economically feasible.

[1] Based on six (6) past rate cases in 2016/ 2017 with reported “return on original cost rate” for California utilities, including Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric. Pending 2018/ 2019 rates cases suggest potential increases in the returns for these cases.

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This memorandum is divided into several sections. The first provides the summary of findings; the second describes the alternatives evaluated; and the third describes the feasibility analysis, including cost and revenues assumptions and the estimated rates of return for the alternatives evaluated.

Key Findings

The three Project Alternatives evaluated are not financially feasible.

The three Project Alternatives - Alternative 3: the Reduced Turbine Footprint – Monument Ridge, Alternative 4: the Reduced Turbine Count, and Alternative 5: the Reduced Turbine Footprint – Bear River Ridge - would be expected to achieve after-tax Internal Rates of Return (IRRs) of well below the 7.0 percent hurdle rate of return. As shown in **Table 1**, under the mid-PPA pricing scenario, all three alternatives produce IRRs of well-below 6.0 percent, ranging from 3.88 percent for Alternative 3 to 5.09 percent for Alternative 4. The expected energy pricing, project development costs (including substantial fixed costs), operating and maintenance costs do not generate sufficient returns even after production tax credits and accelerated depreciation are taken into account.

Table 1. Internal Rates of Return for Proposed Projects and Alternatives [2]

Alternative	Number of Turbines	Megawatts Generated	After-Tax IRR (1)		
			Low PPA	Mid PPA	High PPA
Alternative 3	23	72	2.75%	3.88%	4.90%
Alternative 4	31	97	3.95%	5.09%	6.14%
Alternative 5	27	84	3.42%	4.56%	5.59%

(1) Low, Mid, and High PPA pricing reflects $45, $50, and $55 per megawatt hour respectively.

The substantial gap between the estimated IRRs and the after-tax hurdle IRRs means the feasibility conclusions are robust under a range of sensitivity analyses (e.g. increases in energy prices, reductions in project development costs). To illustrate the robustness of the results, a lower PPA pricing scenario and a higher PPA pricing scenario were also evaluated (both reflecting pricing +/- 10 percent relative to the midpoint pricing). As shown in **Table 1**, even under the higher pricing scenario, the after tax IRRs range from 4.90 percent to 6.14 percent, well below the hurdle rate of return.

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2 The project applicant has informed the County that Alternative 5 needs to be revised from 37 turbines to 27 because that is the maximum number that can be physically accommodated on Monument Ridge. Please see the Master Response on Alternatives in the Final EIR for a more detailed explanation of why wake effect, interference with existing microwave beam paths, and the steepness of the terrain would preclude placement of more than 27 turbines on Monument Ridge.

Description of Project and Project Alternatives

The proposed project site encompasses 124 parcels in Humboldt County with a project footprint beginning west of State Highway 101, south of Rio Dell and Scotia, and terminating east of State Highway 101 in Bridgeville at the PG&E substation. The project would require an expansion of and improvements to the existing substation, an up to 23-mile General Transmission (gen-tie) line, a 19-mile fiber optic system, and up to 17 miles of new access roads. The EIR estimates the project footprint would include up to 650 acres of temporary or permanent impacts.

Section 15126.6(a) of the State CEQA Guidelines requires an evaluation of a range of reasonable alternatives to a proposed project and the comparative merits of each. This analysis focuses on the economic feasibility of three Project Alternatives. Alternative 1: the No Project Alternative and Alternative 2: the Realigned Gen-Tie and Access Road Alternative are not evaluated because the project sponsor has incorporated the realignments proposed in this Alternative into the project.

The Proposed Project consists of 47 turbines capable of generating up to 147 megawatts. The turbines would be located along Monument and Bear River Ridge. Pertinent characteristics of the the three project alternatives evaluated are briefly summarized below. More detailed descriptions of the project alternatives can be found in the EIR

Alternative 3: Reduced Turbine Footprint – Monument Ridge

This alternative reduces the footprint of the project to exclude any construction on Monument Ridge, and decreases the number of turbines from 47 to 23. This reduction in number of turbines is expected to reduce the gross energy generation capacity to about 72 megawatts.

Alternative 4: Reduced Turbine Count

This alternative disperses 31 turbines over the same study corridor as the proposed project, spreading fewer turbines across both Monument and Bear River Ridge. The 31 turbines of this alternative would have a gross energy generation capacity of about 97 megawatts.

Alternative 5: Reduced Turbine Footprint – Bear River Ridge

This alternative avoids any construction on Bear River Ridge by clustering 27 turbines on Monument Ridge. The 27 turbines contemplated in this alternative would have a gross energy generation capacity of about 84 megawatts.

Financial Feasibility Analysis

The project proponent, working with EPS, provided key financial (cost and revenue) estimates developed for the Proposed Project (47 wind turbines and 147 MW capacity) that included estimates of all cost categories and revenue categories. The nature of different cost categories – i.e. fixed vs. variable – was indicated to support the application of this financial information to the three alternatives. Variable costs were assumed to vary proportionately on a per wind turbine basis, while energy sales and production tax credit revenues were varied based on the estimated energy production levels.

EPS reviewed these financial estimates, considered them reasonable, and used them to develop appropriate inputs for standard pro forma cashflow analyses for the three alternatives.[3] Differences between the analyses were driven by the number of turbines and the associated differences in energy production. Because production tax credits and the accelerated depreciation and associated tax benefits provided to wind energy projects are key components of supporting the viability of these projects, these financial characteristics are incorporated into the financial analyses, and an unlevered, after-tax internal rate of return (IRR) was calculated for each alternative.

The after-tax IRR was derived for all alternatives and these IRRs were then compared to the hurdle rate to provide a planning-level indication of development feasibility. The financial analyses, including cost and revenue assumptions and development pro forma outcomes, are described below. **Table 2** provides the underlying revenue and cost assumptions and **Tables 3** through **5** provide the detailed pro forma cash flow analyses for the Mid-Point PPA pricing scenario by alternative.

Key Financial Assumptions

Table 2 summarizes the key financial assumptions developed by Terra-Gen and EPS for the Proposed Project as well as the related information that supports the analyses of the three alternatives (i.e. fixed vs variable costs).

Key assumptions include.

- **Energy Production.** The wind turbines are expected to have a gross generation capacity of about 3.13 MW (mega-watts) per turbine. Consistent with other wind energy projects, the net production is substantially lower at 40 percent of gross capacity, an equivalent of 1.25 MW per turbine or 10,977 MWH (mega-watt hours) per turbine annually.

- **Revenues.** Wind energy sales revenues depend on annual energy production and the energy sales price. Level Ten Energy's PPA (power purchase agreement) Price Index Report for the third quarter of 2019 indicates a current PPA pricing of $50.80 per MWH for the Northern California region. This is rounded down to $50 per MWH for the purposes of the baseline. Mid-point PPA pricing scenario. Additional sensitivities analyses are conducted at PPA pricing of $45 per MWH and $55 per MWH. The pricing is assumed to be fixed under the PPA for the first 15 years of operation. Thereafter, energy will be sold on the merchant/ wholesale market where prices are expected to increase at the pace of inflation from year 16 onwards. Production tax credit revenues are also a key part of the wind energy project profile. The current IRS-approved wind energy production tax credit rate is $25 per MWH, which is expected to increase to about $27 per MWH by the time the project starts producing energy.

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[3] EPS reviewed a number of studies in considering the data provided by project proponent including: USDOE, Office of Energy Efficiency and Renewable Energy, and National Renewable Energy Laboratory (NREL) publications.

Table 2. Financial Estimates for Proposed Project (47 Turbines) and Per Turbine Multipliers

Item	Proposed Project	Notes	Per Turbine
Energy Production			
Gross Production	147	MW	3.13 MW
minus	50%	Gross Capacity Factor	
minus	10%	Additional Loss Factor	
Net Production	40%	of Gross Production	1.25 MW
Annual Net Energy Production	8,766	Average Hours per Year	10,967 MWH
Revenues			
Low PPA Energy Price per MWH (1st 15 Years)	$45.00	per MWH	
Mid PPA Energy Price per MWH (1st 15 Years)	$50.00	per MWH	
High PPA Energy Price per MWH (1st 15 Years)	$55.00	per MWH	
Merchant Energy Price per MWH (16+ Years)	Escalated by inflation after Year 16		
Tax Credit Revenue per MWH/ Credit	$27.00	per MWH	
Project Development Costs			
5 Year MACRS Fixed	$19,089,600		Fixed
5 Year MACRS Variable	$161,289,408		$3,431,690
12 Year Straight Line Fixed/Variable (1)	$94,518,600		Fixed/Variable
15 Year MACRS Fixed	$33,254,000		Fixed
Total Project Development Costs	$308,151,608		$6,556,417
Annual Operating Costs			
General & Administrative (G&A)			
Land Leases	10.5%	of Revenues	N/A
PTAX	$2,100,000	Variable	$44,681
Insurance	$760,000	Variable	$16,170
Other G&A	$530,000	Fixed	N/A
Subtotal G&A	$3,390,000		$72,128
Operating & Maintenance (O&M)			
Turbine Maintenance	$2,800,000	Variable	$59,574
Non-Turbine Maintenance	$780,000	Variable	$16,596
Subtotal O&M	$3,580,000		$76,170
Additional Assumptions			
General Rate of Inflation	2.5%		
Add'l Turbine Maintenance Inflation	1.0%		
Federal Corporate Tax Rate	21%		

(1) Costs depreciated by 12 Year Straight Line method represent 52.4% of the combined 5 Year MACRS fixed and variable costs.

Source: Terra-Gen

- **Project Development Costs.** The development of a wind energy project includes a broad range of upfront investments. Some of these investments/ costs will be fixed independent of the alternative selected, while others will vary with the number of wind turbines. As shown in **Table 2**, Terra-Gen estimated the total project development cost of the proposed project at about $308 million. These costs are distinguished by applicable depreciation schedule which varies by type of cost, with certain wind energy development costs eligible for the accelerated 5-year depreciation (MACRS) schedule that provides important tax benefits to support wind energy project feasibility.

- **Annual Operating Costs.** Annual operating costs include two main categories, general and administrative costs and operating and maintenance costs. General and administrative costs include land lease payments, property tax payments, insurance, and other general administrative costs. As shown in Table 2, land lease costs are tied to energy sales revenues, property taxes vary by alternative though do not inflate over time, insurance costs vary by alternative and increase annually by inflation, and other costs are fixed for all alternatives and increase by inflation annually. Operating and maintenance costs include turbine maintenance costs and non-turbine (balance of plant) maintenance costs. Both cost items are variable on a per turbine basis. The non-turbine costs are increased annually by the assumed rate of general inflation (2.5 percent), while the turbine operating costs are assumed to increase annually by 3.5 percent (this represents the base inflation level of 2.5 percent and an additional 1.0 percent to account for the mechanical nature of the turbines and the need for higher levels of maintenance expenditures to limit the loss of wind energy productivity over life of the turbines).

- **Additional Assumptions**. The additional assumptions shown in **Table 2** include the general rate of inflation used to escalate costs annually where appropriate in the time-series pro forma analyses for each alternative and an additional rate of cost increase for turbine maintenance for reasons described above. The federal corporate tax rate of 21 percent is also noted and, as described below, is applied in the pro forma analyses to help determine the tax benefits associated with the allowed depreciation schedules.

Pro Forma Cashflow Analyses and Results

Tables 3, **4**, and **5** show annual pro forma cashflow analyses for the three alternatives for the mid-PPA pricing scenario. All the analyses follow the same structure, combining the specified number of turbines and associated energy production with the key assumptions described in **Table 2** to calculate each project's net income after tax and the associated after-tax IRR. Key components and results of the pro forma analyses are described below:

- **Duration.** The pro forma analyses are run for a 25-year operating period. This is close to the useful life of wind turbines and provides a substantial time period for analysis. For the purposes of this analysis, it is assumed that decommissiong costs balance with any end-of-period project value. Because the PPA will last 15 years, pricing for the first 15 years is fixed and then adjusted by annual inflation to approximate potential wholesale/ merchant pricing.

- **Energy Production.** Energy production is directly tied to the number of wind turbines and, for analytical simplicity, is assumed to be consistent each year. Annual energy production ranges from about 340,000 MWH under Alternative 4 (the 31-turbine alternative) to about 252,000 MWH under Alternative 3 (the 23-turbine alternative).

- **Energy Sales Revenue.** The consistent energy pricing across the alternatives means that the energy sale revenues scale directly with the number of turbines and the energy production. Annual energy sales revenues, under the mid-PPA pricing scenario, range from $12.6 million annually under Alternative 3 to $17.0 million annually during the PPA period under Alternative 4.

- **Operating Costs.** While operating costs are mostly variable with the number of turbines, a few smaller fixed cost components exist. As a result, operating costs as a percent of revenues are relatively consistent, though increase modestly with the smaller projects, from 45.9 percent under Alternative 4 to 47.3 percent under Alternative 3.

- **Total Project Development Costs.** Of the $308 million in total development costs for the Proposed Project (about $6.6 million per wind turbine), about $62.3 million are assumed to be fixed costs. As a result, as the number of turbines decreases, the total cost per turbine increases. Total project development costs range from $182.6 million ($7.9 million per wind turbine) under Alternative 3 to $224.5 million ($7.25 million per wind turbine) for Alternative 4.

- **Earnings**. The pro forma analyses calculate the earnings/ EBITA, which represents the earnings before taxes, depreciation, and amortization. Earnings are calculated by subtracting operating costs and project development costs from revenues. As shown in **Tables 3**, **4**, and **5**, the earnings all start substantially negative due to the upfront project development costs and are then positive for the duration of the analysis. As shown, the total net earnings (nominal and undiscounted range) decrease with the reduction in the number of turbines, from $19.0 million under Alternative 4 (about 9 percent of total project development costs) to $6.2 million under Alternative 5 (about 3.0 percent of total project development costs) to negative $6.6 million under Alternative 3.

- **Additional Revenues/ Tax Benefits.** These earnings do not generate a sufficient return to constitute a viable project. For wind energy projects, the additional revenues from production tax credits and the tax benefits associated with an accelerated depreciation schedule are key to improving overall returns and increasing the number of viable projects

  \- **Production Tax Credits**. Wind energy projects receive production tax credits on a per-kilowatt-hour (KWH) basis in an amount adjusted by the IRS annually. In 2019, the rate is set at $0.025 per-KWH, which equates to $25 per MWH. Terra-Gen forecasts that this rate will increase to $27 per MWH when energy production begins. The production tax credits apply for the first ten (10) years of project operation. This rate is applied to energy production under each alternative and is escalated annually by the rate of inflation.

  \- **Depreciation/ Tax Benefits**. Renewable energy projects can depreciate some of their costs at a pace faster than typically allowed, bringing forward some of the benefits of depreciation. As shown in the cash flow analyses, a substantial proportion of project development costs (some fixed and some variable) can be depreciated under the accelerated 5-year MACRS schedule, established by the IRS and provided by Terra-Gen. When the depreciation schedule is combined with earnings to determine taxable income and the current federal corporate tax rate is applied, the potential tax savings/ costs each year are established. For all alternatives, though to different degrees, the first five years result in tax savings, meaning that the project owner can use the negative taxable income to offset tax obligations from other ventures.

- **Net Income after Tax**. The annual cashflow of net income after tax equals the sum of the earnings, tax benefits/ costs, and production tax credits. From this after-tax net income stream, the after-tax IRR can be calculated, a barometer for project feasibility when compared to the hurdle rate of return. As shown, the after-tax IRRs for the mid-PPA princing scenario range from 3.88 percent (under Alternative 3), to 5.09 percent (under Alternative 4), to 4.56 percent (under Alternative 5). All of these returns fall far short of the hurdle rate of 7.5 percent and are not feasible.

This analysis concludes that Alternatives 3, 4, and 5 are economically infeasible because they do not produce a sufficient rate of return for a reasonably prudent investor to proceed with development.

Table 3
Humboldt Wind Energy Project Financial Analysis - ALTERNATIVE 3 (Mid PPA Pricing)
Turbines: 23
MW: 72

Item		Total	0	1	2	3	4	5	6	7	8	9	10	11	12
OVERAL PROJECT ECONOMICS															
Energy Production															
Annual Net Energy Production (mWh)			0	252,237	252,237	252,237	252,237	252,237	252,237	252,237	252,237	252,237	252,237	252,237	252,237
Energy Sales Revenue															
PPA revenue		$189,177,740	$0	$12,611,849	$12,611,849	$12,611,849	$12,611,849	$12,611,849	$12,611,849	$12,611,849	$12,611,849	$12,611,849	$12,611,849	$12,611,849	$12,611,849
Merchant Revenue		$144,827,747	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual Revenues		**$334,005,488**	**$0**	**$12,611,849**	**$12,611,849**	**$12,611,849**	**$12,611,849**	**$12,611,849**	**$12,611,849**	**$12,611,849**	**$12,611,849**	**$12,611,849**	**$12,611,849**	**$12,611,849**	**$12,611,849**
Annual Operating Costs															
General & Administrative (G&A)															
Land Leases		$35,070,576	$0	$1,324,244	$1,324,244	$1,324,244	$1,324,244	$1,324,244	$1,324,244	$1,324,244	$1,324,244	$1,324,244	$1,324,244	$1,324,244	$1,324,244
PTAX		$25,691,489	$0	$1,027,660	$1,027,660	$1,027,660	$1,027,660	$1,027,660	$1,027,660	$1,027,660	$1,027,660	$1,027,660	$1,027,660	$1,027,660	$1,027,660
Insurance		$12,703,781	$0	$371,915	$381,213	$390,743	$400,512	$410,524	$420,788	$431,307	$442,090	$453,142	$464,471	$476,083	$487,985
Other G&A		$18,103,615	$0	$530,000	$543,250	$556,831	$570,752	$585,021	$599,646	$614,638	$630,003	$645,754	$661,897	$678,445	$695,406
Subtotal G&A		$91,569,462	$0	$3,253,819	$3,276,367	$3,299,478	$3,323,167	$3,347,449	$3,372,338	$3,397,849	$3,423,997	$3,450,799	$3,478,272	$3,506,431	$3,535,294
Operating & Maintenance (O&M)															
Turbine Maintenance		$53,369,591	$0	$1,370,213	$1,418,170	$1,467,806	$1,519,179	$1,572,351	$1,627,383	$1,684,341	$1,743,293	$1,804,309	$1,867,459	$1,932,820	$2,000,469
Non-Turbine Maintenance		$13,038,091	$0	$381,702	$391,245	$401,026	$411,051	$421,328	$431,861	$442,657	$453,724	$465,067	$476,694	$488,611	$500,826
Subtotal O&M		$66,407,682	$0	$1,751,915	$1,809,415	$1,868,832	$1,930,231	$1,993,678	$2,059,244	$2,126,999	$2,197,017	$2,269,376	$2,344,153	$2,421,431	$2,501,295
Total Operating Costs		**$157,977,144**	**$0**	**$5,005,734**	**$5,085,781**	**$5,168,310**	**$5,253,398**	**$5,341,127**	**$5,431,582**	**$5,524,847**	**$5,621,014**	**$5,720,175**	**$5,822,425**	**$5,927,862**	**$6,036,590**
	47.3%	of annual revenues													
Project Development Costs															
5 Year MACRS Fixed		$19,089,600	$19,089,600												
5 Year MACRS Variable		$78,928,859	$78,928,859												
12 Year Straight Line Fixed/Variable		$51,361,673	$51,361,673												
15 Year MACRS Fixed		$33,254,000	$33,254,000												
Total Development Costs		**$182,634,132**	**$182,634,132**												
Total Development Cost per Turbine		$7,940,614													
Earnings (EBITDA) (1)		**($6,605,788)**	**($182,634,132)**	**$7,606,116**	**$7,526,068**	**$7,443,539**	**$7,358,451**	**$7,270,722**	**$7,180,268**	**$7,087,002**	**$6,990,835**	**$6,891,674**	**$6,789,424**	**$6,683,987**	**$6,575,260**
Depreciation				**($46,799,010)**	**($30,788,995)**	**($21,083,233)**	**($17,291,059)**	**($17,039,461)**	**($6,243,755)**	**($6,243,755)**	**($6,243,755)**	**($6,243,755)**	**($6,243,755)**	**($6,243,755)**	**($5,887,077)**
5 Years MACRS (2)				40%	24%	14%	11%	11%							
12 Years SL (2)				8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
15 Year MACRS (2)				10%	9%	8%	7%	7%	6%	6%	6%	6%	6%	6%	6%
Taxable Income				**($39,192,894)**	**($23,262,927)**	**($13,639,693)**	**($9,932,608)**	**($9,768,739)**	**$936,513**	**$843,247**	**$747,080**	**$647,920**	**$545,670**	**$440,232**	**$688,183**
Tax Benefits/ Costs (3)	**21%**	**$1,304,553**		**$8,230,508**	**$4,885,215**	**$2,864,336**	**$2,085,848**	**$2,051,435**	**($196,668)**	**($177,082)**	**($156,887)**	**($136,063)**	**($114,591)**	**($92,449)**	**($144,518)**
Energy Credit Revenues		**$76,299,496**		**$6,810,399**	**$6,980,659**	**$7,155,175**	**$7,334,054**	**$7,517,406**	**$7,705,341**	**$7,897,974**	**$8,095,424**	**$8,297,809**	**$8,505,255**		
Net Income After Tax (4)		**$70,998,262**	**($182,634,132)**	**$22,647,022**	**$19,391,941**	**$17,463,050**	**$16,778,353**	**$16,839,563**	**$14,688,941**	**$14,807,895**	**$14,929,372**	**$15,053,421**	**$15,180,089**	**$6,591,538**	**$6,430,741**
Unlevered After Tax IRR	**3.88%**														

Item	13	14	15	16	17	18	19	20	21	22	23	24	25
OVERAL PROJECT ECONOMICS													
Energy Production													
Annual Net Energy Production (mWh)	252,237	252,237	252,237	252,237	252,237	252,237	252,237	252,237	252,237	252,237	252,237	252,237	252,237
Energy Sales Revenue													
PPA revenue	$12,611,849	$12,611,849	$12,611,849	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Merchant Revenue	$0	$0	$0	$12,927,146	$13,250,324	$13,581,582	$13,921,122	$14,269,150	$14,625,879	$14,991,526	$15,366,314	$15,750,472	$16,144,233
Annual Revenues	**$12,611,849**	**$12,611,849**	**$12,611,849**	**$12,927,146**	**$13,250,324**	**$13,581,582**	**$13,921,122**	**$14,269,150**	**$14,625,879**	**$14,991,526**	**$15,366,314**	**$15,750,472**	**$16,144,233**
Annual Operating Costs													
General & Administrative (G&A)													
Land Leases	$1,324,244	$1,324,244	$1,324,244	$1,357,350	$1,391,284	$1,426,066	$1,461,718	$1,498,261	$1,535,717	$1,574,110	$1,613,463	$1,653,800	$1,695,145
PTAX	$1,027,660	$1,027,660	$1,027,660	$1,027,660	$1,027,660	$1,027,660	$1,027,660	$1,027,660	$1,027,660	$1,027,660	$1,027,660	$1,027,660	$1,027,660
Insurance	$500,184	$512,689	$525,506	$538,644	$552,110	$565,912	$580,060	$594,562	$609,426	$624,662	$640,278	$656,285	$672,692
Other G&A	$712,791	$730,611	$748,876	$767,598	$786,788	$806,458	$826,619	$847,285	$868,467	$890,178	$912,433	$935,244	$958,625
Subtotal G&A	$3,564,879	$3,595,203	$3,626,286	$3,691,252	$3,757,841	$3,826,096	$3,896,057	$3,967,767	$4,041,269	$4,116,610	$4,193,833	$4,272,988	$4,354,121
Operating & Maintenance (O&M)													
Turbine Maintenance	$2,070,486	$2,142,953	$2,217,956	$2,295,584	$2,375,930	$2,459,087	$2,545,155	$2,634,236	$2,726,434	$2,821,859	$2,920,624	$3,022,846	$3,128,646
Non-Turbine Maintenance	$513,347	$526,181	$539,335	$552,818	$566,639	$580,805	$595,325	$610,208	$625,463	$641,100	$657,127	$673,556	$690,395
Subtotal O&M	$2,583,832	$2,669,133	$2,757,291	$2,848,403	$2,942,569	$3,039,892	$3,140,480	$3,244,444	$3,351,897	$3,462,959	$3,577,752	$3,696,402	$3,819,040
Total Operating Costs	**$6,148,712**	**$6,264,337**	**$6,383,577**	**$6,539,654**	**$6,700,410**	**$6,865,988**	**$7,036,537**	**$7,212,211**	**$7,393,167**	**$7,579,569**	**$7,771,585**	**$7,969,390**	**$8,173,161**
Earnings (EBITDA) (1)	**$6,463,138**	**$6,347,513**	**$6,228,272**	**$6,387,491**	**$6,549,914**	**$6,715,594**	**$6,884,585**	**$7,056,939**	**$7,232,712**	**$7,411,957**	**$7,594,729**	**$7,781,082**	**$7,971,072**
Depreciation	**($1,963,615)**	**($1,963,615)**	**($1,961,910)**										
5 Years MACRS (2)													
12 Years SL (2)													
15 Year MACRS (2)	6%	6%	6%										
Taxable Income	**$4,499,522**	**$4,383,897**	**$4,266,363**	**$6,387,491**	**$6,549,914**	**$6,715,594**	**$6,884,585**	**$7,056,939**	**$7,232,712**	**$7,411,957**	**$7,594,729**	**$7,781,082**	**$7,971,072**
Tax Benefits/ Costs (3)	**($944,900)**	**($920,618)**	**($895,936)**	**($1,341,373)**	**($1,375,482)**	**($1,410,275)**	**($1,445,763)**	**($1,481,957)**	**($1,518,869)**	**($1,556,511)**	**($1,594,893)**	**($1,634,027)**	**($1,673,925)**
Energy Credit Revenues													
Net Income After Tax (4)	**$5,518,238**	**$5,426,894**	**$5,332,336**	**$5,046,118**	**$5,174,432**	**$5,305,319**	**$5,438,822**	**$5,574,982**	**$5,713,842**	**$5,855,446**	**$5,999,836**	**$6,147,055**	**$6,297,147**

(1) EBITDA = Earnings before taxes, depreciation, and amortization. Total Revenues minus Operating Costs minus Project Development Costs.
(2) IRS-established depreciation rates.
(3) Potential tax benefits/ costs equal federal corporate tax multiplied by taxable income. When postive, the owner of the wind farm can offset other tax liabilities, thereby obtaining a positive tax benefit.
(4) Net After Tax Income = Earnings (EBITA) plus Tax Savings plus Energy Credit Revenues.

Sources: Terra-Gen; Economic & Planning Systems, Inc.

Table 4
Humboldt Wind Energy Project Financial Analysis - ALTERNATIVE 4 (Mid PPA Pricing)
Turbines: 31
MW: 97

Item		Total	0	1	2	3	4	5	6	7	8	9	10	11	12
OVERAL PROJECT ECONOMICS															
Energy Production															
Annual Net Energy Production (mWh)			0	339,972	339,972	339,972	339,972	339,972	339,972	339,972	339,972	339,972	339,972	339,972	339,972
Energy Sales Revenue															
PPA revenue		$254,978,694	$0	$16,998,580	$16,998,580	$16,998,580	$16,998,580	$16,998,580	$16,998,580	$16,998,580	$16,998,580	$16,998,580	$16,998,580	$16,998,580	$16,998,580
Merchant Revenue		$195,202,616	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual Revenues		**$450,181,310**	**$0**	**$16,998,580**	**$16,998,580**	**$16,998,580**	**$16,998,580**	**$16,998,580**	**$16,998,580**	**$16,998,580**	**$16,998,580**	**$16,998,580**	**$16,998,580**	**$16,998,580**	**$16,998,580**
Annual Operating Costs															
General & Administrative (G&A)															
Land Leases		$47,269,037	$0	$1,784,851	$1,784,851	$1,784,851	$1,784,851	$1,784,851	$1,784,851	$1,784,851	$1,784,851	$1,784,851	$1,784,851	$1,784,851	$1,784,851
PTAX		$34,627,660	$0	$1,385,106	$1,385,106	$1,385,106	$1,385,106	$1,385,106	$1,385,106	$1,385,106	$1,385,106	$1,385,106	$1,385,106	$1,385,106	$1,385,106
Insurance		$17,122,488	$0	$501,277	$513,809	$526,654	$539,820	$553,316	$567,148	$581,327	$595,860	$610,757	$626,026	$641,676	$657,718
Other G&A		$18,103,615	$0	$530,000	$543,250	$556,831	$570,752	$585,021	$599,646	$614,638	$630,003	$645,754	$661,897	$678,445	$695,406
Subtotal G&A		$117,122,800	$0	$4,201,234	$4,227,016	$4,253,442	$4,280,529	$4,308,294	$4,336,752	$4,365,922	$4,395,821	$4,426,468	$4,457,880	$4,490,078	$4,523,082
Operating & Maintenance (O&M)															
Turbine Maintenance		$71,932,927	$0	$1,846,809	$1,911,447	$1,978,347	$2,047,590	$2,119,255	$2,193,429	$2,270,199	$2,349,656	$2,431,894	$2,517,010	$2,605,106	$2,696,284
Non-Turbine Maintenance		$17,573,079	$0	$514,468	$527,330	$540,513	$554,026	$567,877	$582,073	$596,625	$611,541	$626,829	$642,500	$658,563	$675,027
Subtotal O&M		$89,506,006	$0	$2,361,277	$2,438,777	$2,518,860	$2,601,615	$2,687,132	$2,775,503	$2,866,824	$2,961,197	$3,058,724	$3,159,511	$3,263,668	$3,371,311
Total Operating Costs		**$206,628,806**	**$0**	**$6,562,510**	**$6,665,792**	**$6,772,303**	**$6,882,145**	**$6,995,425**	**$7,112,255**	**$7,232,746**	**$7,357,018**	**$7,485,191**	**$7,617,391**	**$7,753,747**	**$7,894,393**
	45.9%	of annual revenues													
Project Development Costs															
5 Year MACRS Fixed		$19,089,600	$19,089,600												
5 Year MACRS Variable		$106,382,375	$106,382,375												
12 Year Straight Line Fixed/Variable		$65,747,315	$65,747,315												
15 Year MACRS Fixed		$33,254,000	$33,254,000												
Total Development Costs		**$224,473,291**	**$224,473,291**												
Total Development Cost per Turbine		$7,241,074													
Earnings (EBITDA) (1)		**$19,079,213**	**($224,473,291)**	**$10,436,069**	**$10,332,787**	**$10,226,277**	**$10,116,435**	**$10,003,154**	**$9,886,325**	**$9,765,833**	**$9,641,561**	**$9,513,388**	**$9,381,189**	**$9,244,833**	**$9,104,187**
Depreciation				**($58,975,404)**	**($38,574,353)**	**($26,233,969)**	**($21,455,100)**	**($21,200,926)**	**($7,442,558)**	**($7,442,558)**	**($7,442,558)**	**($7,442,558)**	**($7,442,558)**	**($7,442,558)**	**($6,985,980)**
5 Years MACRS (2)				40%	24%	14%	11%	11%							
12 Years SL (2)				8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
15 Year MACRS (2)				10%	9%	8%	7%	7%	6%	6%	6%	6%	6%	6%	6%
Taxable Income				**($48,539,334)**	**($28,241,565)**	**($16,007,692)**	**($11,338,665)**	**($11,197,772)**	**$2,443,767**	**$2,323,275**	**$2,199,003**	**$2,070,830**	**$1,938,630**	**$1,802,274**	**$2,118,207**
Tax Benefits/ Costs (3)	**21%**	**($4,112,279)**		**$10,193,260**	**$5,930,729**	**$3,361,615**	**$2,381,120**	**$2,351,532**	**($513,191)**	**($487,888)**	**($461,791)**	**($434,874)**	**($407,112)**	**($378,478)**	**($444,823)**
Energy Credit Revenues		**$102,838,451**		**$9,179,233**	**$9,408,714**	**$9,643,932**	**$9,885,030**	**$10,132,156**	**$10,385,460**	**$10,645,096**	**$10,911,223**	**$11,184,004**	**$11,463,604**		
Net Income After Tax (4)		**$117,805,385**	**($224,473,291)**	**$29,808,562**	**$25,672,230**	**$23,231,824**	**$22,382,584**	**$22,486,842**	**$19,758,594**	**$19,923,042**	**$20,090,994**	**$20,262,518**	**$20,437,680**	**$8,866,355**	**$8,659,363**
Unlevered After Tax IRR	**5.09%**														

Item	13	14	15	16	17	18	19	20	21	22	23	24	25
OVERAL PROJECT ECONOMICS													
Energy Production													
Annual Net Energy Production (mWh)	339,972	339,972	339,972	339,972	339,972	339,972	339,972	339,972	339,972	339,972	339,972	339,972	339,972
Energy Sales Revenue													
PPA revenue	$16,998,580	$16,998,580	$16,998,580	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Merchant Revenue	$0	$0	$0	$17,423,544	$17,859,133	$18,305,611	$18,763,251	$19,232,333	$19,713,141	$20,205,969	$20,711,119	$21,228,897	$21,759,619
Annual Revenues	**$16,998,580**	**$16,998,580**	**$16,998,580**	**$17,423,544**	**$17,859,133**	**$18,305,611**	**$18,763,251**	**$19,232,333**	**$19,713,141**	**$20,205,969**	**$20,711,119**	**$21,228,897**	**$21,759,619**
Annual Operating Costs													
General & Administrative (G&A)													
Land Leases	$1,784,851	$1,784,851	$1,784,851	$1,829,472	$1,875,209	$1,922,089	$1,970,141	$2,019,395	$2,069,880	$2,121,627	$2,174,667	$2,229,034	$2,284,760
PTAX	$1,385,106	$1,385,106	$1,385,106	$1,385,106	$1,385,106	$1,385,106	$1,385,106	$1,385,106	$1,385,106	$1,385,106	$1,385,106	$1,385,106	$1,385,106
Insurance	$674,161	$691,015	$708,291	$725,998	$744,148	$762,752	$781,820	$801,366	$821,400	$841,935	$862,983	$884,558	$906,672
Other G&A	$712,791	$730,611	$748,876	$767,598	$786,788	$806,458	$826,619	$847,285	$868,467	$890,178	$912,433	$935,244	$958,625
Subtotal G&A	$4,556,910	$4,591,583	$4,627,124	$4,708,175	$4,791,251	$4,876,405	$4,963,687	$5,053,152	$5,144,853	$5,238,847	$5,335,190	$5,433,942	$5,535,163
Operating & Maintenance (O&M)													
Turbine Maintenance	$2,790,654	$2,888,327	$2,989,419	$3,094,048	$3,202,340	$3,314,422	$3,430,427	$3,550,492	$3,674,759	$3,803,376	$3,936,494	$4,074,271	$4,216,870
Non-Turbine Maintenance	$691,902	$709,200	$726,930	$745,103	$763,731	$782,824	$802,395	$822,454	$843,016	$864,091	$885,694	$907,836	$930,532
Subtotal O&M	$3,482,557	$3,597,527	$3,716,349	$3,839,152	$3,966,071	$4,097,246	$4,232,821	$4,372,946	$4,517,775	$4,667,467	$4,822,187	$4,982,107	$5,147,402
Total Operating Costs	**$8,039,466**	**$8,189,111**	**$8,343,473**	**$8,547,326**	**$8,757,322**	**$8,973,651**	**$9,196,509**	**$9,426,098**	**$9,662,628**	**$9,906,313**	**$10,157,377**	**$10,416,049**	**$10,682,565**
Project Development Costs													
Earnings (EBITDA) (1)	**$8,959,113**	**$8,809,469**	**$8,655,107**	**$8,876,218**	**$9,101,811**	**$9,331,960**	**$9,566,742**	**$9,806,234**	**$10,050,513**	**$10,299,656**	**$10,553,741**	**$10,812,847**	**$11,077,054**
Depreciation	**($1,963,615)**	**($1,963,615)**	**($1,961,910)**										
5 Years MACRS (2)													
12 Years SL (2)													
15 Year MACRS (2)	6%	6%	6%										
Taxable Income	**$6,995,498**	**$6,845,853**	**$6,693,197**	**$8,876,218**	**$9,101,811**	**$9,331,960**	**$9,566,742**	**$9,806,234**	**$10,050,513**	**$10,299,656**	**$10,553,741**	**$10,812,847**	**$11,077,054**
Tax Benefits/ Costs (3)	**($1,469,055)**	**($1,437,629)**	**($1,405,571)**	**($1,864,006)**	**($1,911,380)**	**($1,959,712)**	**($2,009,016)**	**($2,059,309)**	**($2,110,608)**	**($2,162,928)**	**($2,216,286)**	**($2,270,698)**	**($2,326,181)**
Energy Credit Revenues													
Net Income After Tax (4)	**$7,490,059**	**$7,371,840**	**$7,249,535**	**$7,012,212**	**$7,190,430**	**$7,372,248**	**$7,557,727**	**$7,746,925**	**$7,939,905**	**$8,136,728**	**$8,337,456**	**$8,542,150**	**$8,750,872**

(1) EBITDA = Earnings before taxes, depreciation, and amortization. Total Revenues minus Operating Costs minus Project Development Costs.
(2) IRS-established depreciation rates.
(3) Potential tax benefits/ costs equal federal corporate tax multiplied by taxable income. When postive, the owner of the wind farm can offset other tax liabilities, thereby obtaining a positive tax benefit.
(4) Net After Tax Income = Earnings (EBITA) plus Tax Savings plus Energy Credit Revenues.

Sources: Terra-Gen; Economic & Planning Systems, Inc.

Table 5
Humboldt Wind Energy Project Financial Analysis - ALTERNATIVE 5 (Mid PPA Pricing)
Turbines: 27
MW: 84

Item		Total	0	1	2	3	4	5	6	7	8	9	10	11	12
OVERAL PROJECT ECONOMICS															
Energy Production															
Annual Net Energy Production (mWh)			0	296,104	296,104	296,104	296,104	296,104	296,104	296,104	296,104	296,104	296,104	296,104	296,104
Energy Sales Revenue															
PPA revenue		$222,078,217	$0	$14,805,214	$14,805,214	$14,805,214	$14,805,214	$14,805,214	$14,805,214	$14,805,214	$14,805,214	$14,805,214	$14,805,214	$14,805,214	$14,805,214
Merchant Revenue		$170,015,182	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual Revenues		**$392,093,399**	**$0**	**$14,805,214**	**$14,805,214**	**$14,805,214**	**$14,805,214**	**$14,805,214**	**$14,805,214**	**$14,805,214**	**$14,805,214**	**$14,805,214**	**$14,805,214**	**$14,805,214**	**$14,805,214**
Annual Operating Costs															
General & Administrative (G&A)															
Land Leases		$41,169,807	$0	$1,554,548	$1,554,548	$1,554,548	$1,554,548	$1,554,548	$1,554,548	$1,554,548	$1,554,548	$1,554,548	$1,554,548	$1,554,548	$1,554,548
PTAX		$30,159,574	$0	$1,206,383	$1,206,383	$1,206,383	$1,206,383	$1,206,383	$1,206,383	$1,206,383	$1,206,383	$1,206,383	$1,206,383	$1,206,383	$1,206,383
Insurance		$14,913,134	$0	$436,596	$447,511	$458,698	$470,166	$481,920	$493,968	$506,317	$518,975	$531,950	$545,248	$558,879	$572,851
Other G&A		$18,103,615	$0	$530,000	$543,250	$556,831	$570,752	$585,021	$599,646	$614,638	$630,003	$645,754	$661,897	$678,445	$695,406
Subtotal G&A		$104,346,131	$0	$3,727,526	$3,751,691	$3,776,460	$3,801,848	$3,827,871	$3,854,545	$3,881,885	$3,909,909	$3,938,634	$3,968,076	$3,998,255	$4,029,188
Operating & Maintenance (O&M)															
Turbine Maintenance		$62,651,259	$0	$1,608,511	$1,664,809	$1,723,077	$1,783,384	$1,845,803	$1,910,406	$1,977,270	$2,046,475	$2,118,101	$2,192,235	$2,268,963	$2,348,377
Non-Turbine Maintenance		$15,305,585	$0	$448,085	$459,287	$470,769	$482,539	$494,602	$506,967	$519,641	$532,632	$545,948	$559,597	$573,587	$587,926
Subtotal O&M		$77,956,844	$0	$2,056,596	$2,124,096	$2,193,846	$2,265,923	$2,340,405	$2,417,373	$2,496,912	$2,579,107	$2,664,050	$2,751,832	$2,842,550	$2,936,303
Total Operating Costs		**$182,302,975**	**$0**	**$5,784,122**	**$5,875,787**	**$5,970,306**	**$6,067,772**	**$6,168,276**	**$6,271,918**	**$6,378,797**	**$6,489,016**	**$6,602,683**	**$6,719,908**	**$6,840,805**	**$6,965,491**
		46.5% of annual revenues													
Project Development Costs															
5 Year MACRS Fixed		$19,089,600	$19,089,600												
5 Year MACRS Variable		$92,655,617	$92,655,617												
12 Year Straight Line Fixed/Variable		$58,554,494	$58,554,494												
15 Year MACRS Fixed		$33,254,000	$33,254,000												
Total Development Costs		**$203,553,711**	**$203,553,711**												
Total Development Cost per Turbine		$7,539,026													
Earnings (EBITDA) (1)		**$6,236,713**	**($203,553,711)**	**$9,021,092**	**$8,929,428**	**$8,834,908**	**$8,737,443**	**$8,636,938**	**$8,533,296**	**$8,426,418**	**$8,316,198**	**$8,202,531**	**$8,085,307**	**$7,964,410**	**$7,839,723**
Depreciation				**($52,887,207)**	**($34,681,674)**	**($23,658,601)**	**($19,373,080)**	**($19,120,194)**	**($6,843,157)**	**($6,843,157)**	**($6,843,157)**	**($6,843,157)**	**($6,843,157)**	**($6,843,157)**	**($6,436,528)**
5 Years MACRS (2)				40%	24%	14%	11%	11%							
12 Years SL (2)				8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
15 Year MACRS (2)				10%	9%	8%	7%	7%	6%	6%	6%	6%	6%	6%	6%
Taxable Income				**($43,866,114)**	**($25,752,246)**	**($14,823,693)**	**($10,635,637)**	**($10,483,255)**	**$1,690,140**	**$1,583,261**	**$1,473,042**	**$1,359,375**	**$1,242,150**	**$1,121,253**	**$1,403,195**
Tax Benefits/ Costs (3)	**21%**	**($1,403,863)**		**$9,211,884**	**$5,407,972**	**$3,112,975**	**$2,233,484**	**$2,201,484**	**($354,929)**	**($332,485)**	**($309,339)**	**($285,469)**	**($260,851)**	**($235,463)**	**($294,671)**
Energy Credit Revenues		**$89,568,974**		**$7,994,816**	**$8,194,686**	**$8,399,553**	**$8,609,542**	**$8,824,781**	**$9,045,400**	**$9,271,535**	**$9,503,324**	**$9,740,907**	**$9,984,429**		
Net Income After Tax (4)		**$94,401,823**	**($203,553,711)**	**$26,227,792**	**$22,532,085**	**$20,347,437**	**$19,580,469**	**$19,663,202**	**$17,223,767**	**$17,365,468**	**$17,510,183**	**$17,657,969**	**$17,808,884**	**$7,728,947**	**$7,545,052**
Unlevered After Tax IRR	**4.56%**														

Item	13	14	15	16	17	18	19	20	21	22	23	24	25
OVERAL PROJECT ECONOMICS													
Energy Production													
Annual Net Energy Production (mWh)	296,104	296,104	296,104	296,104	296,104	296,104	296,104	296,104	296,104	296,104	296,104	296,104	296,104
Energy Sales Revenue													
PPA revenue	$14,805,214	$14,805,214	$14,805,214	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Merchant Revenue	$0	$0	$0	$15,175,345	$15,554,728	$15,943,597	$16,342,187	$16,750,741	$17,169,510	$17,598,748	$18,038,716	$18,489,684	$18,951,926
Annual Revenues	**$14,805,214**	**$14,805,214**	**$14,805,214**	**$15,175,345**	**$15,554,728**	**$15,943,597**	**$16,342,187**	**$16,750,741**	**$17,169,510**	**$17,598,748**	**$18,038,716**	**$18,489,684**	**$18,951,926**
Annual Operating Costs													
General & Administrative (G&A)													
Land Leases	$1,554,548	$1,554,548	$1,554,548	$1,593,411	$1,633,246	$1,674,078	$1,715,930	$1,758,828	$1,802,799	$1,847,868	$1,894,065	$1,941,417	$1,989,952
PTAX	$1,206,383	$1,206,383	$1,206,383	$1,206,383	$1,206,383	$1,206,383	$1,206,383	$1,206,383	$1,206,383	$1,206,383	$1,206,383	$1,206,383	$1,206,383
Insurance	$587,173	$601,852	$616,898	$632,321	$648,129	$664,332	$680,940	$697,964	$715,413	$733,298	$751,631	$770,422	$789,682
Other G&A	$712,791	$730,611	$748,876	$767,598	$786,788	$806,458	$826,619	$847,285	$868,467	$890,178	$912,433	$935,244	$958,625
Subtotal G&A	$4,060,894	$4,093,393	$4,126,705	$4,199,713	$4,274,546	$4,351,250	$4,429,872	$4,510,459	$4,593,061	$4,677,728	$4,764,512	$4,853,465	$4,944,642
Operating & Maintenance (O&M)													
Turbine Maintenance	$2,430,570	$2,515,640	$2,603,687	$2,694,816	$2,789,135	$2,886,755	$2,987,791	$3,092,364	$3,200,597	$3,312,617	$3,428,559	$3,548,559	$3,672,758
Non-Turbine Maintenance	$602,625	$617,690	$633,133	$648,961	$665,185	$681,814	$698,860	$716,331	$734,240	$752,596	$771,411	$790,696	$810,463
Subtotal O&M	$3,033,195	$3,133,330	$3,236,820	$3,343,777	$3,454,320	$3,568,569	$3,686,651	$3,808,695	$3,934,836	$4,065,213	$4,199,970	$4,339,254	$4,483,221
Total Operating Costs	**$7,094,089**	**$7,226,724**	**$7,363,525**	**$7,543,490**	**$7,728,866**	**$7,919,820**	**$8,116,523**	**$8,319,154**	**$8,527,897**	**$8,742,941**	**$8,964,481**	**$9,192,719**	**$9,427,863**
Earnings (EBITDA) (1)	**$7,711,125**	**$7,578,491**	**$7,441,690**	**$7,631,855**	**$7,825,862**	**$8,023,777**	**$8,225,664**	**$8,431,587**	**$8,641,612**	**$8,855,806**	**$9,074,235**	**$9,296,965**	**$9,524,063**
Depreciation	**($1,963,615)**	**($1,963,615)**	**($1,961,910)**										
15 Year MACRS (2)	6%	6%	6%										
Taxable Income	**$5,747,510**	**$5,614,875**	**$5,479,780**	**$7,631,855**	**$7,825,862**	**$8,023,777**	**$8,225,664**	**$8,431,587**	**$8,641,612**	**$8,855,806**	**$9,074,235**	**$9,296,965**	**$9,524,063**
Tax Benefits/ Costs (3)	**($1,206,977)**	**($1,179,124)**	**($1,150,754)**	**($1,602,689)**	**($1,643,431)**	**($1,684,993)**	**($1,727,389)**	**($1,770,633)**	**($1,814,739)**	**($1,859,719)**	**($1,905,589)**	**($1,952,363)**	**($2,000,053)**
Net Income After Tax (4)	**$6,504,148**	**$6,399,367**	**$6,290,936**	**$6,029,165**	**$6,182,431**	**$6,338,784**	**$6,498,274**	**$6,660,954**	**$6,826,874**	**$6,996,087**	**$7,168,646**	**$7,344,602**	**$7,524,010**

(1) EBITDA = Earnings before taxes, depreciation, and amortization. Total Revenues minus Operating Costs minus Project Development Costs.
(2) IRS-established depreciation rates.
(3) Potential tax benefits/ costs equal federal corporate tax multiplied by taxable income. When postive, the owner of the wind farm can offset other tax liabilities, thereby obtaining a positive tax benefit.
(4) Net After Tax Income = Earnings (EBITA) plus Tax Savings plus Energy Credit Revenues.

Sources: Terra-Gen; Economic & Planning Systems, Inc.

Attachment 4

November 12, 2019

Greenhouse Gas Benefit Calculations

Beth,

Here are comparisons of the project with the alternatives in terms of numeric achievement of certain project objectives, specifically, CO2 displacement, households served and equivalent cars off the road.

We know that the GHG displacement calculations differ from those in the final EIR as calculated by AECOM. However, Terra Gen stands behind the GHG displacement figures in the attached Benefits Calculation based on a net capacity factor of 40%. AECOM used a 30% NCF, which is incorrect for this wind farm.

Equivalency Results

How are they calculated?

The sum of the greenhouse gas emissions you entered above is of Carbon Dioxide Equivalent. This is equivalent to:

384,068 **Metric Tons**

Greenhouse gas emissions from

81,543

Passenger vehicles driven for one year

-or-

939,041,201

Miles driven by an average passenger vehicle

CO_2 emissions from

43,216,817

gallons of gasoline consumed

-or-

37,727,687

gallons of diesel consumed

-or-

419,872,936

Pounds of coal burned

-or-

5,084

tanker trucks' worth of gasoline

-or-

45,991

homes' energy use for one year

-or-

66,976

homes' electricity use for one year

-or-

2,095

railcars' worth of coal burned

-or-

889,198

barrels of oil consumed

-or-

15,700,582

propane cylinders used for home barbeques

-or-

0.099

-or-

48,973,382,08

power plants in one year

smartphones charged

Greenhouse gas emissions avoided by

133,961

Tons of waste recycled instead of landfilled

-or-

19,136

Garbage trucks of waste recycled instead of landfilled

-or-

16,757,618

trash bags of waste recycled instead of landfilled

-or-

81.4

Wind turbines running for a year

-or-

14,588,364

Incandescent lamps switched to LEDs

Carbon sequestered by

6,350,643

tree seedlings grown for 10 years

-or-

452,018

acres of U.S. forests in one year

-or-

3,117

acres of U.S. forests preserved from conversion to cropland in one year

Energy Produced									
Calculation	Project MW	% of time WTG operate at full capacity~ Net Capacity Factor (includes all losses)	Hours / yr			MWh/yr	kWh/yr	Source	Link to Source
Multiply hours in a year by project megawatts at 40% capacity	**155**	**40.0%**	8,760			543,120	543,120,000		
Total CO2 avoided									
Calculation	lbs CO2/MWh	Metric tons/lb	MWh/kWh	Metric tons CO2/kWh	kWh/yr	Total metric tons of CO2 avoided per yr			
kWh/yr * Metric Tons CO2/kWh	1559	0.0004536	0.001	0.000707162	543,120,000	**384,074**	This calculation includes line losses	United States Environmental Protection Agency	https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references
Cars Removed									
Calculation	Metric tons of CO2 avoided by the project	Metric tons of CO2 emitted per year per car				Total cars off the road per yr			
Metric tons of CO2 avoided by the project/average car emission	384,074	4.6				**83,494**		United States Environmental Protection Agency	https://www.epa.gov/greenvehicles/greenhouse-gas-emissions-typical-passenger-vehicle
Houses Powered									
Calculation	Average CA Household electricity consumption / yr (kWh)				kWh/yr	Total homes powered per yr			
Project annual MW hours/annual MW per home	7,500				543,120,000	**72,416**		Humboldt County General Plan Update, Revised Draft EIR	https://humboldtgov.org/DocumentCenter/View/58846/Section-317-Energy-Consumption-and-Conservation-Revised-DEIR-PDF
Alternative	Project Size	MWH/Yr	Total metric tons of CO2 avoided per yr	Fewer metric tons of carbon dioxide displaced	Cars removed from the road	Fewer cars removed from the road	# of homes served with renewable energy	Fewer homes served with renewable energy	
Basecase	155	-	**384,074**		**83,494**		**72,416**		
3	72	-	178,409	205,665	38,784	44,710	33,638	38,778	
4	97	-	240,356	143,718	52,251	31,243	45,318	27,098	
5	84	-	208,143	175,931	45,249	38,245	39,245	33,171	
What differs from the FEIR				Modeled	Actual	Error			
	Page 8	Capacity Factor	30%	407340	543,120	-33.33%			

Humboldt Wind Project FEIR Errata 11/12/13

The following corrections have been made to the FEIR since publication on 11/1/19:

The Table of Contents has been amended to include the following sub-header in Chapter 5:

Table 6-1 in Chapter 6 of the FEIR has been updated to correct a misspelled name as follows:

Table 6-1. List of Written Comments Received from Tribes

Letter Number	Commenter	Tribe/Organization Represented	Date Received
T1	Rosie Clayburn, M.A., Tribal Heritage Preservation Officer	Yurok Tribe	June 6, 2019
T2	Adam M. Cant~~o~~er, Tribal Botanist, GIS, and THPO Cultural Assistant	Wiyot Tribe	June 14, 2019

Accordingly, the header for Response to Comment Letter T2 has been revised as follows:

Letter T2 Response, Adam Cant~~o~~er, Wiyot Tribe, June 14, 2019

The following additional individual letter has been added to Chapter 8.2

Letter I-243 Carol Michael

The commenter expresses concern regarding the end of the comment period and the lack of public information regarding proposed activity in Fields Landing including turning a residential neighborhood into a commercial venue and enlarging the freeway.

Information on proposed activities at Fields Landing is included in Section 2.3.1, "*Component Shipping and Staging*," in the Project Description of the FEIR, and detailed information on transport of turbine components is included in Section 2.3.2, "*Component Transport to the Project Site*". Improvement at Fields Landing would be temporary. No widening of the freeway is proposed.

The following additional form letters have been added to Chapter 8.2 8B – Form letters of the FEIR (* indicates minor variation from form letter; topic of variation is indicated in parentheses):

Letter Number	Commenter	Date Submitted
A110	A. Todd	June 7, 2019
A111	Aline Faben* (wildlife on ridge)	June 7, 2019

A112	Ana Canter	June 8, 2019
A113	Anette Larsson	June 9, 2019
A114	Ann White	June 8, 2019
A115	Annie Wei	June 8, 2019
A116	Barbara Graham	June 7, 2019
A117	Boel Stridbeck	June 7, 2019
A118	Bonita Dombrowski	June 7, 2019
A119	Bonnie MacRaith	June 7, 2019
A120	Chelsea Pulliam	June 10, 2019
A121	Christa Neuber	June 8, 2019
A122	Christine Hayes	June 9, 2019
A123	Christine Stewart	June 9, 2019
A124	Colin Smith	June 8, 2019
A124	Daniel Aubouard	June 8, 2019
A126	Daniel Tubbs	June 8, 2019
A127	David Burtis	June 7, 2019
A128	Davin Peterson	June 8, 2019
A129	Denise Lytle	June 9, 2019
A130	Deb Lincoln	June 8, 2019
A131	Denise Thomas	June 8, 2019
A132	Dennis Ledden	June 8, 2019
A133	Elizabeth Grainger	June 8, 2019
A134	Ellen Golla	June 9, 2019
A135	Gaile Carr	June 9, 2019
A136	Henry Kruger	June 11, 2019
A137	Isabel Cervera	June 11, 2019
A138	J. David Scott	June 8, 2019
A139	J.T. Smith	June 7, 2019
A140	James Lansing	June 7, 2019
A141	James Maurer	June 10, 2019
A142	James Wolcott	June 8, 2019
A143	Jan Modjeski	June 7, 2019
A144	Janet Forman	June 10, 2019
A145	Janna Caughron	June 8, 2019
A146	Jeanette Holmgren	June 8, 2019
A147	Jeannie Pollak	June 7, 2019
A148	John Livingston	June 9, 2019
A149	John Zuehlke	June 8, 2019
A150	Joseph Ashenbrucker	June 9, 2019
A151	Joyce Coe	June 7, 2019
A152	Judy Genandt	June 7, 2019
A153	Julian Battersby	June 8, 2019
A154	K R	June 7, 2019
A155	Karen DeBraal	June 7, 2019
A156	Karen Furniss	June 7, 2019
A157	Karen Olsen	June 8, 2019
A158	Karen Ratzlaff	June 8, 2019
A159	Kate Robinson	June 7, 2019
A160	Kristen Renton	June 8, 2019

A161	Krystal Weilage	June 8, 2019
A162	Lacey Levitt	June 8, 2019
A163	Larry Blakely* (earthquakes, move project elsewhere)	June 8, 2019
A164	Laszlo Kurucz	June 7, 2019
A165	Lawrence Thompson	June 8, 2019
A166	Lenore Reeves	June 7, 2019
A167	Leslene Dunn	June 9, 2019
A168	Margie Zalesak	June 7, 2019
A169	Mark Bastian	June 8, 2019
A170	Mark M Giese	June 8, 2019
A171	Marlen Hdz	June 7, 2019
A172	Martina Patterson	June 8, 2019
A173	Mary Eastman	June 7, 2019
A174	Mary F Platter-Rieger	June 9, 2019
A175	Maureen O'Neal	June 7, 2019
A176	Mauricio Carvajal	June 7, 2019
A177	Maxine Litwak	June 7, 2019
A178	Melanie Kasek	June 8, 2019
A179	Meqghan Simpson* (EMF, health concerns)	June 9, 2019
A180	Michaela Rohr	June 11, 2019
A181	Natalie Van Leekwijck	June 7, 2019
A182	Nathan Wise* (Jordan Creek fish, vegetation management, herbicides, TPZ land conversion, condor, Wiyot support)	June 8, 2019
A183	Nina Spelter	June 8, 2019
A184	Nora Davidson* (turbine sound, wildlife, marbled murrelet, hoary bats)	June 7, 2019
A185	Peter Dobbins	June 7, 2019
A186	R. Zoss	June 7, 2019
A187	Raleigh Koritz	June 8, 2019
A188	Rev. Elizabeth Zenker	June 8, 2019
A189	Rick Pelren	June 7, 2019
A190	Robin Hamlin	June 8, 2019
A191	Robin Morton	June 8, 2019
A192	Roth Woods	June 8, 2019
A193	Sandy Goncarovs* (wildlife, marbled murrelets, hoary bats)	June 9, 2019
A194	Sheila Desmond	June 8, 2019
A195	Shubra Sachdev	June 9, 2019
A196	Silvia Bertano	June 9, 2019
A197	Sue Ghilotti	June 9, 2019
A198	Tanja Rieger	June 8, 2019
A199	Thomas Moore	June 7, 2019
A200	Tina Colafranceschi	June 9, 2019

A201	Tracey Kleber	June 10, 2019
A202	Vicky Matsui	June 8 2019

All topics mentioned in these letters are included in the DEIR or in the Responses to Comments in the FEIR, including in the Master Responses. Earthquakes are discussed in DEIR Section 3.7, Geology and Soils; EMFs and health concerns are discussed in DEIR Section 3.9, Hazards and Hazardous Materials; fisheries and wildlife issues are discussed in DEIR Section 3.5 Biological Resources; condor and other tribal cultural resources are discussed in DEIR Section 3.6, Cultural Resources including Tribal Cultural Resources; TPZs are discussed in DEIR Section 3.3, Agriculture and Forestry Resources; turbine noise is discussed in DEIR Section 3.11, Noise. No further responses are necessary.

One additional organizational comment letter was received and inadvertently got left out of the FEIR. **Comment Letter O17 – California Native Plant Society,** is hereby included in the FEIR. The coded comment letter is attached and a detailed Response to Comment is provided.

Letter O17

CALIFORNIA NATIVE PLANT SOCIETY

North Coast Chapter
P.O. Box 1067
Arcata, CA 95518

June 14, 2019

To: California Humboldt Wind Project Planner
County of Humboldt
Planning and Building Department, Planning Division
3015 H Street, Eureka, CA 95501
CEQAResponses@co.humboldt.ca.us

Subject: Comments on Humboldt Wind Energy Project Draft Environmental Impact Report

The California Native Plant Society (CNPS) is a statewide, non-profit environmental organization with over 10,000 members in 35 Chapters across California and Baja California, Mexico. CNPS' mission is to protect California's native plant heritage and preserve it for future generations through application of science, research, education, and conservation. CNPS works closely with decision-makers, scientists, and local planners to advocate for well-informed policies, regulations, and land management practices. The North Coast Chapter has 370 members, mostly in Humboldt and Del Norte Counties.

We encourage projects to avoid impacts to rare, threatened, and endangered species as well as important habitats. We are greatly concerned about project impacts to birds and other animal species, but our comments focus on elements of the environment pertaining to botanical diversity, habitat types, climate change, aesthetics, and recreation. The DEIR states that the Humboldt Wind Energy Project (Project) has the potential to impact 417.63 acres of sensitive natural communities (other than riparian habitats); 1.77 acres of riparian habitats; 5.25 acres of wetlands and other waters; and 8.86 acres of special-status plants. It's very rare that a proposed project on the North Coast would have this large magnitude of impacts. While we support renewable energy, concerns remain regarding the appropriateness of the project location given its biodiversity and uniqueness. **We question whether renewable energy needs to come at this great an expense of significant impacts to the environment.** O17-1

An important part of the California Environmental Quality Act (CEQA) process is disclosure of the Project's potential impacts on the environment so that the public may comment on those impacts and the details of proposed mitigations. Unfortunately, the biological surveys presented in the DEIR are incomplete and do not provide adequate coverage of the project area. Additionally, the DEIR does not present detailed mitigation plans for rare plants, natural communities, invasive species, eelgrass, wetland, and riparian impacts in a manner sufficient for the public to evaluate feasibility and site-specific appropriateness. Mitigations that refer to a pending "Reclamation, Revegetation, and Weed Control Plan" constitute deferred mitigation and are not acceptable. Given the potential for **undisclosed impacts and the presentation of** O17-2

deferred mitigations, the DEIR should be re-circulated with the findings of a complete biological surveys, impact analyses, and detailed mitigation plans. O17-2 (Cont.)

We offer the following, more specific comments and recommendations:

1. The botanical study area for the project was partially surveyed in the year 2018, and additional surveys are planned in 2019. **Botanical surveys** should be completed for the entire project area so that the methods and findings of the surveys are disclosed to the public for review and commenting as part of a recirculated DEIR. Additionally, please clarify if project components in the Highway 101 transportation corridor will be surveyed. O17-3
2. The DEIR does not adequately address whether California Rare Plant Rank (CRPR) 3 or 4 taxa were evaluated for impact significance based on CEQA sections 15125(c) and/or 15380. Some of these species may be rare or unique to the region. Additionally, there may be species that are rare or locally unique that do not have a CRPR. The DEIR should provide a **more thorough analysis for these rare taxa** and include species-specific justification if a case is made that 15125(c) and/or 15380 does not apply. O17-4
3. The DEIR states that for impacts to Siskiyou Checkerbloom the Project applicant shall develop a mitigation strategy with a minimum 1.5 to 1 mitigation ratio. Given that (based on an incomplete botanical survey) 8.86 acres of Special-Status Plants may be impacted by the project, a **specific and feasible in-kind mitigation plan** must be included in the DEIR for public review and commenting. Additionally, the DEIR should provide examples of prior successful Siskiyou Checkerbloom mitigation and a justification for the mitigation ratio that was proposed. This comment also applies to other rare plant species, sensitive natural communities, riparian habitats, and wetlands that will be impacted. We are particularly interested in a more detailed analysis of the unique and imperiled **coastal prairie habitats**. O17-5
4. Eelgrass habitat is designated as essential fish habitat and is subject to no-net-loss wetland policies. The project may impact eelgrass, yet project-specific eelgrass surveys were not presented in the DEIR for public review. In accordance with the California Eelgrass Mitigation Policy and Implementing Guidelines, pre-project and post-project eelgrass surveys within the areas of potential effects need to occur. The Project must demonstrate feasibility to mitigate direct and indirect potential **impacts to eelgrass** at a 4.82 to 1 mitigation ratio. The impact analysis should also include a feasible mitigation plan to mitigate for the highest potential impact area. O17-6
5. We are concerned about the spread of invasive species already within the Project area and the potential for the introduction of new invasive species. The magnitude of earth-moving and road building and the abundance of traffic offer too great an opportunity for non-native, especially invasive, plant species to move in. The DEIR does not provide an **invasive species management plan**. The Project's pending Reclamation, Revegetation, and Weed Control Plan was not provided in the DEIR for review and commenting and, therefore, the DEIR and does not provide adequate detail on how invasive plant species will be managed. O17-7
6. To minimize impacts to native vegetation, the Project's pending mitigation plan should include specific measures for **conserving native topsoil** and ensuring that top soil is O17-8

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salvaged and replaced at the source location after grading activities. Additionally, the mitigation plan should consider **habitat-specific cattle grazing and management strategies** that will benefit declining native grasslands and other early succession plant communities. O17-8 (Cont.)

7. The DEIR should provide a thorough analysis of impacts to the **ethnobotanical cultural landscapes and tribal resources.** O17-9
8. The DEIR should provide a more thorough analysis of the project's **carbon footprint**. What is the net reduction in carbon emissions if construction, transport, and all maintenance costs are evaluated? How will project build-out affect the project site's ability to sequester carbon before and after project implementation? O17-10
9. We are concerned about the Project's effects on **aesthetics**. The DEIR analyzes impacts from distant view sheds, but omits analysis of aesthetic impacts to botanical enthusiasts, bird watchers, and nature lovers that pass through the actual project (e.g. Bear River Ridge's rare and unique coastal prairies) area on public roads. This aesthetic experience will be greatly diminished. O17-11
10. We are concerned about the Project's effects on **recreation**. Similar to our comment on aesthetics, how will project construction and implementation effect botanical enthusiasts, bird watchers, and nature lovers that pass through the actual project area on public roads. This recreational experience will be greatly diminished. O17-12
11. We are concerned about elements of project infrastructure that would remain on-site after the life of the project, including concrete pads at the base of wind turbines. Concrete pads, even if buried, will have an impact on the ecological processes of coastal prairie and other habitats. There needs to be a requirement to **decommission and remove all infrastructure** at the end of the project life. O17-13
12. Given that the Project may result in significant impacts to the environment, the Project should further explore **alternative sites**. The DEIR only briefly mentions that alternative sites were considered, but these alternative sites were not included in the DEIR analysis of Project Alternative. Less impactful alternatives that meet the project's objectives may exist. We'd like to see further evaluation of alternative locations and project designs. O17-14
13. Given the Project Alternatives presented, inadequacies of the DEIR, and comments we have provided, **we recommend the "No Project" alternative**.

Thank you for consideration.

Sincerely,

Carol Ralph

Carol Ralph
President

Letter O17 Response — **Carol Ralph, President**
California Native Plant Society, North Coast Chapter
June 14, 2019

O17-1 *The commenter introduces the California Native Plant Society, North Coast Chapter (NCPS)a non-profit environmental organization is to protect California's native plant heritage and preserve it for future generations through application of science, research, education, and conservation. The commenter summarizes the impacts of the project on sensitive plant communities and questions whether renewable energy needs should come at the expense of significant impacts on the environment.*

The commenter's expresses concern about the impacts of the project on sensitive species but does not raise specific questions or request information that pertains to the adequacy of the Draft EIR for addressing adverse physical impacts associated with the project, nor does it contain an argument raising significant environmental issues. No further response is required.

O17-2 *The commenter states that the biological surveys described in the DEIR are incomplete and do not provide sufficient mitigation plans for rare plants, natural communities, invasive species, eelgrass, wetland and riparian habitat. The commenter also states that mitigation is deferred to a pending Reclamation, Revegetation and Weed Control Plan and that the DEIR should be recirculated with completed surveys, impact analyses and mitigation plans.*

As discussed in Master Response 7, "*Special-status Plants and Sensitive Natural Communities*," in 2019 Stantec botanists conducted additional botanical surveys of those areas not previously surveyed, including the eastern portion of the gen-tie line, the Fields Landing area, the transportation improvement areas, and additional areas outside of the original gen-tie corridor, that were added to the project area since publication of the DEIR to aid in avoidance of known sensitive biological resources. The methods and results of the 2019 protocol-level special-status plant surveys are included in a report called "*Humboldt Wind Energy Project – 2019 Botanical Resources Survey Result Memo*" dated August 27 (See Appendix B of this FEIR). The botanical survey area for 2019 (which includes areas surveyed previously in 2018) is approximately 1,140 acres. The reduction in project area acreage is due to changes in the project footprint.

Since circulation of the DEIR, the applicant has developed the Reclamation, Revegetation and Weed Control Plan, which is included in Appendix C of the FEIR.

O17-3 *The commenter states that the project was only partially surveyed for plants in 2018 and requests disclosure of 2019 survey results. The commenter also requested clarification as to whether the Highway 101 transportation corridor was surveyed.*

Please see response to Comment O17-2 above, which describes the 2019 botanical surveys. The Highway 101 transportation corridor improvement areas were covered in these surveys.

O17-4 *The commenter states that the DEIR does not adequately address whether California Rare Plant Rank (CRPR) 3 or 4 taxa were evaluated for impact significance based on CEQA sections 15125(c) and/or 15380, noting that some of these species may be rare or unique to the region. The commenter notes that* *there may be species that are rare or locally unique that do not have a CRPR, and states that the DEIR should provide a more thorough analysis for these rare taxa and include species-specific justification if a case is made that 15125(c) and/or 15380 does not apply.*

The survey results presented in the botanical resources technical reports include documentation of California Rare Plant Rank (CRPR) List 3 and 4 species. The DEIR did not include an analysis of these species because they do not meet the definition of endangered or rare under CEQA Guidelines 15380(b) or (c). The commenter does not indicate that any of the CRPR 3 and 4 species identified in the background technical reports that would warrant specific CEQA consideration. No revisions are necessary.

O17-5 *The commenter requests a specific and feasible in-kind mitigation plan for Siskiyou checkerbloom, and justification for the 1.5:1 mitigation ratio, and states that this comment also applies to other rare plant species, sensitive natural communities, riparian habitats, and wetlands that will be impacted. The commenter is particularly interested in a more detailed analysis of the unique and imperiled coastal prairie habitats.*

Please Master Response 7, "*Special-status Plants and Sensitive Natural Communities*," and the *Reclamation, Revegetation, and Weed Control Plan* in Appendix B in this FEIR; specifically Chapter 5. Monitoring, Success Criteria and Annual Performance Standards, for a discussion of proposed mitigation and performance standards for mitigation for Siskiyou checkerbloom and other sensitive plant communities.

As discussed in Section 3.1, Master Response 1, "*Site Planning and Avoidance Measures*," the project applicant has made changes to the project to avoid and minimize impacts on sensitive resources throughout the planning and concept design process, including impacts on special-status plants and sensitive communities. Master Response 7 provides details on the acreages of reduced impacts on sensitive plant communities.

O17-6 *The commenter notes that project specific eelgrass surveys were not presented in the DEIR and states that pre-project and post-project eelgrass surveys within the areas of potential effects need to occur in compliance with California Eelgrass Mitigation Policy and Implementing Guidelines, pre-project and post-project eelgrass surveys within the areas of potential effects need to occur.*

Since circulation of the DEIR, the project applicant has retained a qualified consultant to further refine the mapping of the extent of eelgrass at Fields Landing and propose recommendations to ensure the project's avoidance of eelgrass (see *Eelgrass Avoidance Recommendations for the Humboldt Wind Energy Project* prepared by Merkel & Associates, Inc., June 2019, in Appendix B of this FEIR). As stated in the DEIR, the project will not result in impacts on eelgrass, and no project activity is proposed within areas of Humboldt Bay at Fields Landing that support eelgrass. Project activities are not expected to result in excessive wake or sediment disturbance that would result in impact on eel grass present in the vicinity of the landing site. The Final EIR has been revised to include the avoidance recommendations provided in this memo, including pre- and post-project eelgrass surveys. Please see Chapter 9 of the FEIR for a track change version of Mitigation Measure 3.5-22c. that incorporates these changes.

O17-7 *The commenter expresses concern about the spread of invasive species already within the Project area and the potential for the introduction of new invasive species, noting that the pending Reclamation, Revegetation, and Weed Control Plan was not provided in the DEIR for review.*

Please see the *Reclamation, Revegetation, and Weed Control Plan* in Appendix B in this FEIR for a discussion of how invasive weed management will be implemented during project construction.

O17-8 *The commenter states that the pending mitigation plan should include specific measures for conserving native topsoil and ensuring that top soil is salvaged and replaced at the source location after grading activities. The commenter also states that the mitigation plan should consider habitat-specific cattle grazing and management strategies that will benefit declining native grasslands and other early succession plant communities.*

Please see the Reclamation, Revegetation, and Weed Control Plan in Appendix B in this FEIR for a discussion of topsoil salvage and seedbed preparation. Regarding the commenter's suggestion that grazing be managed to benefit native grasslands, please note that the project applicant does not have control over the grazing regimes at the project site because it does not own the land but rather leases it from private landowners.

O17-9 *The commenter states that the DEIR should provide a thorough analysis of impacts to the ethnobotanical cultural landscapes and tribal resources.*

Please see DEIR Section 3.6 (Cultural Resources, Including Tribal Cultural Resources) for a thorough discussion of cultural landscapes and tribal resources.

O17-10 *The commenter states that the DEIR should provide a more thorough analysis of the project's carbon footprint, including the net reduction in carbon emissions if construction, transport, and all maintenance costs are evaluated, and how project build-out will affect the project site's ability to sequester carbon before and after project implementation.*

This topic is discussed in detail in Section 3.8, Greenhouse Gas Emissions, of the DEIR. Please also see Master Response 9, "*Adequacy of the Greenhous Gas Analysis*," for a discussion of the project's carbon footprint and a description of how project build-out will sequester carbon before and after project implementation. Appendix B of the FEIR provides details on the *Updated Criteria Air Pollutant and Greenhouse Gas Emissions Calculations* that support the analysis in the Master Response.

O17-11 *The commenter expresses concerns about the Project's effects on aesthetics, noting that the DEIR analyzes impacts from distant viewsheds, but omits analysis of aesthetic impacts to botanical enthusiasts, bird watchers, and nature lovers that pass through the actual project (e.g. Bear River Ridge's rare and unique coastal prairies) area on public roads.*

The commenter expresses concern about the effects of the project on aesthetics, and the effects on botanists, bird watchers, and nature enthusiasts, but does not raise specific questions or request information that pertains to the adequacy of the DEIR for addressing adverse physical impacts associated with the project, nor does it contain an argument raising significant environmental issues. This comment is published in this Response to Comments document for public disclosure and for decision maker consideration. No further response is required.

Please note that the majority of the project area is not currently open to recreation or general public access. Therefore, no negative impacts on recreation are expected.

O17-12 The commenter expresses concerns about the Project's effects on recreation, noting that project construction and implementation will affect botanical enthusiasts, bird watchers, and nature lovers that pass through the actual project area on public roads.

Please see response to Comment O17-11 above

O17-13 The commenter expresses concerns about elements of project infrastructure that would remain on-site after the life of the project, including concrete pads at the base of wind turbines. The commenter states that concrete pads, even if buried, will have an impact on the ecological processes of coastal prairie and other habitats, and that there needs to be a requirement to decommission and remove all infrastructure at the end of the project life.

Project decommissioning is discussed in Section 2.5, "Project Decommissioning and Restoration," in Chapter 2, "Project Description," of the DEIR. As stated in Section 2.5, upon decommissioning of the facility, the turbines would be removed from the project site, and the materials would be reused or sold for scrap. Any underground utility improvements would be abandoned in place. Restoration of disturbed lands would occur in accordance with regulations and/or the landowner's contractual commitments. The County will be requiring a bond from the applicant to ensure sufficient funds are available to decommission the project and revegetate and restore disturbed areas.

As stated in Section 2.5, decommissioning would require a separate discretionary permit from the County and would require removal of the WTGs, cables, and other infrastructure support facilities. An environmental analysis of decommissioning would be conducted during CEQA review required to issue the decommissioning permit. Restoration and reclamation of disturbed areas that would occur under decommissioning would be addressed in the CEQA document.

It should be noted that while the project lifespan is approximately 30 years the project may undergo a repower. Repowering would require discretionary review by the County and is subject to CEQA. It is not clear how changing technologies may change the structure of power generation and delivery in the next 25 year, and it would be speculative to attempt to predict the actions of the owner/operator 30 years into the future. CEQA discourages a lead agency from speculation. For either repowering or decommissioning a CEQA review would be conducted at the time the applicant seeks discretionary approvals to conduct the decommissioning or repowering.

O17-14 The commenter requests further exploration of alternative sites and states that the DEIR only briefly mentions that alternative sites were considered, but these alternative sites were not included in the DEIR analysis. The commenter would like to see further evaluation of alternative locations and project designs.

Please see Master Response 11, "*Alternatives*," for a detailed discussion of alternatives, including a discussion of off-site locations and alternative designs suggested by commenters.