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DONOVAN E. WALKER
Lead Counsel
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July 24, 2012

VIA HAND DELIVERY

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
Boise, Idaho 83702

Re: Case No. IPC-E-12-20
Complaint and Petition of Idaho Power Company for Declaratory Order

Dear Ms. Jewell:

Enclosed for filing in the above matter are an original and three (3) copies of the Complaint and Petition of Idaho Power Company for Declaratory Order.

Pursuant to our inquiry early today, it is Idaho Power Company's understanding that you, the Commission Secretary, has authorized Idaho Power Company, pursuant to RP 61.04, to modify the number of copies and form of the filing as follows:

1. Reduce the number of copies that must be filed to an original and three (3) copies; and

2. That the filed materials be provided to the Commission in electronic format.

Thank you for your prompt attention and consideration.

Very truly yours,

Donovan E. Walker

DEW:csb
Enclosures

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Boise, ID 83707

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Attorneys for Idaho Power Company

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE COMPLAINT AND PETITION OF IDAHO POWER COMPANY FOR A DECLARATORY ORDER REGARDING THE FIRM ENERGY SALES AGREEMENTS AND GENERATOR INTERCONNECTION AGREEMENTS WITH COTTONWOOD WIND PARK, LLC; DEEP CREEK WIND PARK , LLC; ROGERSON FLATS WIND PARK, LLC; AND SALMON CREEK WIND PARK, LLC.	CASE NO. IPC-E-12-20 IDAHO POWER COMPANY'S COMPLAINT AND PETITION FOR DECLARATORY ORDER

COMES NOW the Petitioner/Complainant, Idaho Power Company ("Idaho Power"), by and through its attorneys, Donovan Walker and Jason Williams, and pursuant to this Commission's Rules of Procedure, including but not limited to RP 54 and RP 101, hereby files this Complaint and Petition for Declaratory Order.

Communications regarding this Complaint and Petition for Declaratory Order should be sent to:

Donovan Walker
Jason Williams
Idaho Power Company
1221 West Idaho Street (83702)
P.O. Box 70
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SUMMARY OF THE CASE

1. This is a dispute between Idaho Power and four special purpose entities that are intended to own and control wind generation projects to be developed by Exergy Development Group of Idaho, LLC ("Exergy"), a sophisticated developer with extensive knowledge and experience with such projects[1]. Idaho Power and the special purpose entities entered into four separate Firm Energy Sales Agreements ("FESA") pursuant to the Public Utility Regulatory Policies Act of 1978 ("PURPA"), each of which provides that the special purpose entity will design, construct, own, maintain and operate an electric wind generation facility and that Idaho Power will buy firm electric energy produced by the facility.

2. The FESAs require, among other things, that the special purpose entity meet certain construction deadlines, such as placing the project in service by the Scheduled Operation Date of June 30, 2012. Exergy selected the Scheduled Operation Date of June 30, 2012, for each FESA. In so doing, Exergy was expressly advised of

[1] See, IPUC Case Nos. IPC-E-05-06, IPC-E-05-07, IPC-E-05-09, IPC-E-05-17, IPC-E-05-18, IPC-E-05-30, IPC-E-05-31, IPC-E-05-32, IPC-E-05-33, IPC-E-09-18, IPC-E-09-19, IPC-E-09-20, all of which are large wind QF developments on Idaho Power's system by Exergy Development.

the risk in obligating itself to a Scheduled Operation Date in the FESA prior to such time that the interconnection and transmission studies had been completed so as to know the required facilities, estimated cost, and estimated timeline for the construction of the required interconnection and transmission facilities. Exergy expressly stated that it was aware of and accepted the risk that delays in the interconnection or transmission process may result in the assessment and application of delay damages. Exergy did not achieve the Scheduled Operation Date of June 30, 2012, and will likely not achieve the Operation Date by September 28, 2012. Exergy and the special purpose entities now assert that alleged "delays" by Idaho Power excuse Exergy's obligation to meet its Scheduled Operation Date. Idaho Power disagrees that any action excuses Exergy or the special purpose entities from meeting their construction deadlines, in part because Exergy elected the Scheduled Operation Date with full awareness of and appreciation for the risks associated with not completing the required interconnection and transmission processes prior to such date.

3. The FESA provides clear remedies for a party's failure to achieve construction deadlines, among them termination of the FESA and delay damages. With this Complaint and Petition, Idaho Power is requesting the Idaho Public Utilities Commission ("Commission") to issue an order declaring that Idaho Power is authorized to apply such remedies against Exergy and the special purpose entities in the event that the Projects are not completed by September 28, 2012. More specifically, Idaho Power asks the Commission to make findings and enter a declaratory order that: 1) the Commission has jurisdiction over the interpretation and enforcement of the FESAs and the GIAs; 2) the Projects have failed to meet the Scheduled Operation Date of June 30,

2012, and that Idaho Power may terminate the FESAs as of September 28, 2012, if the Projects fail to achieve their Operation Date; 3) Exergy's claim of force majeure does not exist so as to excuse the Projects' failure to meet the Scheduled Operation Date; and 4) Idaho Power is entitled to damages pursuant to the FESA.

FACTUAL ALLEGATIONS

4. Idaho Power is an Idaho public utility subject to the jurisdiction of the Commission.

5. Cottonwood Wind Park, LLC ("Cottonwood") is an Idaho limited liability company.

6. Deep Creek Wind Park, LLC ("Deep Creek") is an Idaho limited liability company.

7. Rogerson Flats Wind Park, LLC ("Rogerson Flats") is an Idaho limited liability company.

8. Salmon Creek Wind Park, LLC ("Salmon Creek") is an Idaho limited liability company.

9. Jack Ranch Wind Park, LLC ("Jack Ranch") is an Idaho limited liability company.

10. On March 12, 2010, Exergy submitted a Small Generator Interconnection Requests for four proposed 20 megawatt ("MW") wind generating projects for the Cottonwood Wind Park[2] (the "Cottonwood Project"), the Deep Creek Wind Park[3]

[2] The contracted entity known as Cottonwood Wind Park was originally identified as Jack Ranch Wind Park in the Small Generator Interconnection Request.

[3] The contracted entity known as Deep Creek Wind Park was originally identified as JR-1 in the Small Generator Interconnection Request.

(the "Deep Creek Project"), the Rogerson Flats Wind Park (the "Rogerson Flats Project"), and the Salmon Creek Wind Park (the "Salmon Creek Project")(collectively, the "special purpose entities" or the "Projects"). True and correct copies of the Small Generator Interconnection Requests for the Projects are attached hereto as Attachment 1 and incorporated herein by reference. Idaho Power assigned Generator Interconnection Queue Numbers ("GI #") to each of the Projects as follows:

(i) GI #322 to the Rogerson Flats Project; and

(ii) GI #323 to the Cottonwood Project; and

(iii) GI #324 to the Deep Creek Project; and

(iv) GI #325 to the Salmon Creek Project.

In the Generator Interconnection Request forms Exergy inserted the date "December, 2011" into the blank requesting the "Interconnection Customer's Requested In-Service Date" for each of the Projects. (Attachment 1 at p. 2.)

11. On March 12, 2010, Exergy submitted a Large Generator Interconnection Request for a proposed 200 MW wind generating project for the Jack Ranch Wind Park (the "Jack Ranch Project"). A true and correct copy of the Large Generator Interconnection Request for the Jack Ranch is attached hereto as Attachment 2 and incorporated herein by reference. Idaho Power assigned a Generation Interconnection Project Queue number of 327 to the Jack Ranch Project. Exergy inserted the date "December, 2011" into the blank requesting the "Interconnection Customer's Requested In-Service Date" for the Jack Ranch Project. (Attachment 2 at p. 2.)

12. On March 25, 2010, Idaho Power submitted a Letter of Understanding for the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects to Exergy. True and correct copies of the form Letters of Understanding for the Cottonwood, Deep

Creek, Rogerson Flats, and Salmon Creek Projects are attached hereto as Attachment 3 and incorporated herein by reference. The Letters of Understanding informed Exergy that the Projects appeared to be eligible for a purchase power agreement under the guidelines for a QF as defined by PURPA. (Attachment 3 at p. 1.) The Letters of Understanding also informed Exergy that the Projects must (i) complete the interconnection process and execute a GIA in accordance with the applicable state and federal requirements and (ii) be designated as a DNR to sell the energy from the projects to Idaho Power. (*Id.* at p. 2.)

13. On April 27, 2010, representatives of Idaho Power and Exergy conducted a scoping meeting to discuss alternative interconnection options for the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects, to exchange information including any transmission data that would reasonably be expected to impact such interconnection options, to analyze such information and to determine the potential feasible Points of Interconnection for each of the projects.

14. On April 27, 2010, representatives of Idaho Power and Exergy conducted a scoping meeting to discuss alternative interconnection options for the Jack Ranch Project, to exchange information including any transmission data that would reasonably be expected to impact such interconnection options, to analyze such information and to determine the potential feasible Points of Interconnection for the Jack Ranch Project.

15. On May 13, 2010, Idaho Power tendered to Exergy a form Large Generator Feasibility Study Agreement for the Jack Ranch Project. A true and correct copy of the letter sending the Large Generator Feasibility Study Agreement for the Jack

Ranch Project tendered by Idaho Power is attached hereto as Attachment 4 and incorporated herein by reference.

16. On May 14, 2010, Idaho Power tendered to Exergy a form Small Generator Feasibility Study Agreements for each of the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects. True and correct copies of the letter sending the form Small Generator Feasibility Study Agreements for each of the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects tendered by Idaho Power are attached hereto as Attachment 5 and incorporated herein by reference.

17. On May 19, 2010, Exergy executed and delivered the Small Generator Feasibility Study Agreements for each of the Cottonwood, the Deep Creek, the Rogerson Flats, and the Salmon Creek Projects to Idaho Power. True and correct copies of fully executed Small Generator Feasibility Study Agreements for each of the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects are attached hereto as Attachment 6 and incorporated herein by reference. The Small Generator Feasibility Study Agreements for the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects tendered by Idaho Power included an outline of the scope of the study and a non-binding good faith estimate of the cost to perform such study.

18. On May 19, 2010, Exergy executed and delivered the Large Generator Feasibility Study Agreement for the Jack Ranch Project to Idaho Power. A true and correct copy of the fully executed Large Generator Feasibility Study Agreement for the Jack Ranch Project is attached hereto as Attachment 7 and incorporated herein by reference. The Large Generator Feasibility Study Agreement for the Jack Ranch

Project tendered by Idaho Power included an outline of the scope of the study and a non-binding good faith estimate of the cost to perform such study.

19. On July 1, 2010, Idaho Power issued the Generator Interconnection Feasibility Study Final Reports for the interconnections of the Cottonwood, Deep Creek, and Rogerson Flats Projects to the Upper Salmon B to Wells 138 kV transmission line. True and correct copies of Generator Interconnection Feasibility Study Final Reports for the Cottonwood, Deep Creek, and Rogerson Flats Projects are attached hereto as Attachment 8 and incorporated herein by reference.

20. On July 8, 2010, Idaho Power issued a draft Generator Interconnection Feasibility Study Report for the Salmon Creek and Jack Ranch Projects for the interconnection of the Midpoint – Humboldt 345 kV transmission line. A true and correct copy of the draft Generator Interconnection Feasibility Study Report for the Salmon Creek and Jack Ranch Projects is attached hereto as Attachment 9 and incorporated herein by reference.

21. On July 28, 2010, Idaho Power issued the Generator Interconnection Feasibility Study Final Report for the Salmon Creek and Jack Ranch Projects. A true and correct copy of the Generator Interconnection Feasibility Study Final Report for the Salmon Creek and Jack Ranch Projects is attached hereto as Attachment 10 and incorporated herein by reference.

22. On August 10, 2010, Exergy returned executed Letters of Understanding for the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects to Idaho Power. True and correct copies of the Letters of Understanding for the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects are attached hereto as

Attachment 11 and incorporated herein by reference. Subsequent to receipt of executed Letters of Understanding for the Cottonwood, Deep Creek, Rogerson Flats, Salmon Creek, and Jack Ranch Projects, Idaho Power submitted transmission service requests ("TSR") for these projects.

23. On August 11, 2010, Idaho Power tendered to Exergy a form Large Generator System Impact Study Agreement for the Salmon Creek and Jack Ranch Projects. A true and correct copy of the form Large Generator System Impact Study Agreement for the Salmon Creek and Jack Ranch Projects tendered by Idaho Power is attached hereto as Attachment 12 and incorporated herein by reference.

24. On August 18, 2010, Idaho Power issued a form Small Generator Transmission System Impact Study Agreements for each of the Cottonwood, Deep Creek, and Rogerson Flats Projects. True and correct copy of form Small Generator Transmission System Impact Study Agreements for each of the Cottonwood, Deep Creek, and Rogerson Flats Projects are attached hereto as Attachment 13 and incorporated herein by reference.

25. On August 25, 2010, Exergy returned to Idaho Power executed Small Generator Transmission System Impact Study Agreements for the Cottonwood and Rogerson Flats Projects. True and correct copies of the fully executed Small Generator Transmission System Impact Study Agreements for the Cottonwood and Rogerson Flats Projects are attached hereto as Attachment 14 and incorporated herein by reference.

26. On September 10, 2010, Exergy returned to Idaho Power an executed Large Generator Transmission System Impact Study Agreement for the Salmon Creek

and the Jack Ranch Project. A true and correct copy of the fully executed Large Generator Transmission System Impact Study Agreement for the Salmon Creek and the Jack Ranch Projects is attached hereto as Attachment 15 and incorporated herein by reference.

28. On September 16, 2010, Exergy returned to Idaho Power an executed Small Generator Transmission System Impact Study Agreement for the Deep Creek Project. A true and correct copy of the fully executed Small Generator Transmission System Impact Study Agreement for Deep Creek Projects is attached as Attachment 14 and incorporated herein by reference.

27. On October 26, 2010, Idaho Power informed Exergy that transmission studies would need to be completed for the Cottonwood, Deep Creek, Salmon Creek, and Rogerson Flats Projects. A true and correct copy of the correspondence, dated October 26, 2010, is attached hereto as Attachment 16 and incorporated herein by reference.

28. On October 28, 2010, Exergy submitted the deposits necessary to complete the transmission studies for the Cottonwood, Deep Creek, Salmon Creek, and Rogerson Flats Projects.

29. On November 5, 2010, Idaho Power, Avista Corporation, and PacifiCorp dba Rocky Mountain Power filed a Joint Petition in Case No. GNR-E-10-04 that requested that the Commission initiate an investigation to address various avoided cost issues related to the Commission's implementation of PURPA. The Joint Petition further requested that the Commission "lower the published avoided cost rate eligibility cap from 10 aMW to 100 kW (to) be effective immediately. . . ." Joint Petition at 7.

30. On November 12, 2010, Exergy contacted Idaho Power and indicated that "[t]here is probably no reason we cannot move to contract execution . . . given that they shall be standard agreements." A true and correct copy of the correspondence dated November 12, 2010, is attached hereto as Attachment 17 and incorporated herein by reference. Idaho Power immediately responded as follows:

> As you are most likely aware, with the joint filing that was made at the commission on Nov 5, Idaho Power will not be executing these agreements with the Published avoided cost in them until we get some rulings or guidance from the commission.
>
> If the commission agrees to the request (reduce eligibility from 10 aMW to 100 KW) most likely there will be some form or grandfathering process that we will need to run your projects through to make the determination if we can ultimately sign them or not.
>
> That being said, if the project or projects is less than 80 MW (FERC PURPA threshold) nothing prevents us from working through the process of negotiating an agreement. As you have suggested, there may be some things we could both negotiate into a contract that may be beneficial for everyone.

Attachment 17 at p. 1.

31. On November 15, 2010, counsel for Exergy sent a letter to Idaho Power. A true and correct copy of the letter, dated November 15, 2010, from counsel for Exergy to Idaho Power is attached hereto as Attachment 18 and incorporated herein by reference. Such letter alleged that Idaho Power was in violation of existing Commission orders and Idaho Power's PURPA tariffs:

> This assertion that Idaho Power is now refusing to execute contracts is contrary to law and is a violation of existing Commission orders and Idaho Power's own PURPA tariffs. Failure to execute these contracts will cause my client significant monetary damages because of the delay in proceeding with an executed contract. As you, know time is of the essence with the pending expiration of the federal tax credits at the end of next month. In addition, my client's damages will be greatly enhanced should the

> Commission grant the pending joint motion and joint petition that is referenced in Mr. Allphin's e-mail communication prior to executing the requested contracts.

Attachment 18 at p. 1-2.

32. On November 17, 2010, Idaho Power responded to counsel for Exergy and expressly stated that it was not Idaho Power's position to refuse to sign contracts pursuant to PURPA. A true and correct copy of the letter, dated November 17, 2010, from Idaho Power to counsel for Exergy to Idaho Power is attached hereto as Attachment 19 and incorporated herein by reference. Such letter stated Idaho Power's understanding that Exergy wished to obtain results from the required interconnection and transmission studies prior to executing any Firm Energy Sales Agreement ("FESA"):

> It was Idaho Power's understanding that Mr. Carkulis wished to get the results of the required interconnection and transmission studies, which will identify the need for and cost of interconnection facilities and possible transmission upgrades, prior to the time at which he would sign a Firm Energy Sales Agreement ("FESA") which would obligate the projects to a Scheduled Operation Date. As you are aware, the FESA contains provisions providing for delay damages should the projects fail to meet the Scheduled Operation Date set forth in the FESA. These delay damages are secured by the requirement to post liquid delay damage security thirty (30) days subsequent to IPUC approval of the FESA.

Attachment 19 at p. 1-2.

33. On November 23, 2010, counsel for Exergy sent a letter to Idaho Power expressing Exergy's wish to enter into FESAs for the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects, notwithstanding the incomplete interconnection and transmission processes for such projects. A true and correct copy of the letter, dated November 23, 2010, from counsel for Exergy to Idaho Power is attached hereto as Attachment 20 and incorporated herein by reference. Specifically,

counsel for Exergy stated that Exergy desired to enter into standard FESAs, including a standard $45/kw delay liquidated damages clause prior to completion of the entire interconnection and transmission processes for these projects:

> I write to confirm that Exergy, as the developer of these four projects, is willing to sign contracts including the standard $45/kw delay liquidated damages clause prior to completion of the entire interconnection and transmission processes for these projects, including Idaho Power internal processes required to designate the resource as a network resource. Exergy understands that, under the current standard contract Idaho Power would agree to enter into, a delay in achieving the online date caused by the interconnection or transmission processes is a delay which will not excuse a possible trigger in the delay damages clause.

Attachment 20 at p. 1.

34. On November 24, 2010, Idaho Power sent a letter to counsel for Exergy that acknowledged receipt of the letter, dated November 23, 2010, from counsel for Exergy. A true and correct copy of the letter, dated November 24, 2010, from Idaho Power to counsel for Exergy is attached hereto as Attachment 21 and incorporated herein by reference. In this letter, Idaho Power seeks to confirm that Exergy is aware of and accepts the risk that delays in the interconnection or transmission process may result in the assessment and application of delay damages:

> In addition, your client has been advised, and accepts the risk, that delays in the interconnection or transmission process do not constitute excusable delays in achieving the Scheduled Operation Date, and if the projects fail to achieve the Scheduled Operation Date at the times specified in the FESA, delay damages will be assessed, and delay security applied.

Attachment 21 at p. 1. Additionally, Idaho Power suggested that Exergy select future Scheduled Operation Dates that would allow for completion of the transmission and interconnection processes prior to such date:

> Please allow me to suggest that special consideration be given to the Scheduled Operation Date selected by the projects for inclusion in the FESA, such that with the information available at this time a date is chosen that has a good probability of providing time for the anticipated interconnection and possible transmission upgrades to be completed.

Id.

35. On November 29, 2010, counsel for Exergy responded to the Idaho Power letter, dated November 24, 2010. A true and correct copy of the letter, dated November 29, 2010, from counsel for Exergy to Idaho Power is attached hereto as Attachment 22 and incorporated herein by reference. In this letter, counsel for Exergy confirmed that Exergy is aware of and accepts the risk that delays in the interconnection or transmission process may result in the assessment and application of delay damages:

> Exergy is fully aware of the contracts' provisions and, as you know has successfully developed many projects using the standard Idaho Power contract. Exergy is also fully aware of transmission and interconnection risks, as well as the liquid security provision.
>
> Exergy is ready to execute the agreements and we appreciate the fact that Idaho Power is processing them as quickly as possible, subject only to your standard Sarbanes-Oxley contract approval process.

Attachment 22 at p. 1. Enclosed with the letter were completed FESAs for the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects.

36. On November 29, 2010, Idaho Power issued a draft Generator Interconnection System Impact Study Report for the Cottonwood, Deep Creek, and Rogerson Flats Projects. A true and correct copy of the draft Generator Interconnection System Impact Study Report for the Cottonwood, Deep Creek, and Rogerson Flats Projects is attached hereto as Attachment 23 and incorporated herein by reference.

37. On December 10, 2010, Idaho Power issued a draft Generator Interconnection System Impact Study Report for the Salmon Creek and Jack Ranch Projects. A true and correct copy of the draft Generator Interconnection System Impact Study Report for the Salmon Creek and Jack Ranch Projects is attached hereto as Attachment 24 and incorporated herein by reference.

38. On December 10, 2010, Idaho Power and each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek entered into FESAs for a 20-year term using the then-current non-levelized published avoided cost rates as established by the Commission in Order No. 31025 for energy deliveries of less than 10 aMW. A true and correct copy of the FESAs, dated December 10, 2010, between Idaho Power and each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek is attached hereto as Attachment 25 and incorporated herein by reference. Each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek selected May 30, 2012, as the Scheduled First Energy Date, and June 30, 2012, as the Scheduled Operation Date. Attachment 25 at Appx. B.

39. On December 10, 2010, Idaho Power filed Applications with the Commission in Case Nos. IPC-E-10-47, IPC-E-10-48, IPC-E-10-49, and IPC-E-10-50 requesting acceptance or rejection of the 20-year FESA between Idaho Power and Deep Creek, Cottonwood, Rogerson Flats, and Salmon Creek, respectively.

40. On December 15, 2010, Idaho Power issued a Generator Interconnection System Impact Study Final Report for the Cottonwood, Deep Creek, and Rogerson Flats Project. A true and correct copy of the Generator Interconnection System Impact

Study Final Report for the Cottonwood, Deep Creek, and Rogerson Flats Projects is attached hereto as Attachment 26 and incorporated herein by reference.

41. On December 28, 2010, Idaho Power issued a Transmission Service Request System Impact Study Report for the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects. A true and correct copy of the Transmission Service Request System Impact Study Report for the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects is attached hereto as Attachment 27 and incorporated herein by reference.

42. On December 29, 2010, Idaho Power issued the Generator Interconnection System Impact Study Final Report for the Salmon Creek and Jack Ranch Projects. A true and correct copy of the Generator Interconnection System Impact Study Final Report for the Salmon Creek and Jack Ranch Projects is attached hereto as Attachment 28 and incorporated herein by reference.

43. On January 4, 2011, Idaho Power issued the Generator Interconnection System Impact Study Final Report for the Cottonwood, Deep Creek, and Rogerson Flats Projects. A true and correct copy of the Generator Interconnection System Impact Study Final Report for the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects is attached hereto as Attachment 29 and incorporated herein by reference.

44. On January 13, 2011, Idaho Power tendered to Exergy a form Facilities Study Agreement for the Cottonwood, Deep Creek, and Rogerson Flats Projects. A true and correct copy of the letter and form Facilities Study Agreement for the

Cottonwood, Deep Creek, Rogerson Flats Projects tendered by Idaho Power is attached hereto as Attachment 30 and incorporated herein by reference.

45. On January 11, 2011, Idaho Power tendered to Exergy a form Large Generator Facilities Study Agreement for the Salmon Creek and Jack Ranch Projects. A true and correct copy of the letter sending the form Large Generator Facilities Study Agreement for the Salmon Creek and Jack Ranch Projects tendered by Idaho Power is attached hereto as Attachment 31 and incorporated herein by reference.

46. On February 11, 2011, Exergy executed and delivered to Idaho Power the Interconnection Facilities Study Agreement for the Salmon Creek and Jack Ranch Projects. A true and correct copy of the fully executed Interconnection Facilities Study Agreement for the Salmon Creek and Jack Ranch Project is attached hereto as Attachment 32 and incorporated herein by reference. In the Interconnection Facilities Study Agreement for the Salmon Creek and Jack Ranch Project, Exergy elected to have Idaho Power use reasonable efforts to complete the study and issue a draft Interconnection Facilities Study to Exergy within 180 calendar days. Attachment 32 at p. 6.

47. On February 11, 2011, the Commission issued final orders in Case No. IPC-E-10-47, IPC-E-10-48, IPC-E-10-49, and IPC-E-10-50 that approved the FESAs between Idaho Power and Deep Creek, Cottonwood, Rogerson Flats, and Salmon Creek, respectively, without change or condition.

48. On March 1, 2011, Exergy executed and delivered the Interconnection Facilities Study Agreement for the Deep Creek, Cottonwood, and Rogerson Flats Project to Idaho Power. A true and correct copy of the fully executed Interconnection

Facilities Study Agreement for the Deep Creek, Cottonwood, and Rogerson Flats Projects is attached hereto as Attachment 33 and incorporated herein by reference.

49. On March 4, 2011, Idaho Power sent a letter to Exergy that acknowledged receipt of the executed Interconnection Facilities Study Agreement for the Salmon Creek and Jack Ranch Projects and deposit for the Interconnection Facilities Study. A true and correct copy of the letter, dated March 4, 2011, from Idaho Power is attached hereto as Attachment 34 and incorporated herein by reference.

50. On April 12, 2011, Exergy sent a letter to Idaho Power that, among other things, (i) requested that Idaho Power modify the NR/ER designation for the Jack Ranch Project to be an NR designation only; (ii) reduce the proposed size of generator interconnection for the Jack Ranch Project from 200 MW to 84 MW; and (iii) continue studies for the interconnections of the Deep Creek, Cottonwood, and Rogerson Flats Projects to the Upper Salmon B to Wells 138 kV transmission line. A true and correct copy of the letter, dated April 12, 2011, from Exergy is attached hereto as Attachment 35 and incorporated herein by reference. Such letter stated that reduction in the proposed size of the Jack Ranch Project interconnection from 200 MW to 84 MW was so that such interconnection "may be utilized for the Rogerson Flats, Deep Creek, and Cottonwood wind parks." Attachment 35 at p. 1.

51. On April 27, 2011, Idaho Power responded to the Exergy letter dated April 12, 2011. A true and correct copy of the letter, dated April 27, 2011, from Idaho Power is attached hereto as Attachment 36 and incorporated herein by reference. In its response, Idaho Power, among other things, stated that the modifications proposed in

the Exergy letter dated April 12, 2011, would require a restudy of the transmission system impacts.

52. On April 28, 2011, Exergy sent a letter to Idaho Power objecting to statements in the Idaho Power letter, dated April 27, 2011, that the modifications proposed in the Exergy letter dated April 12, 2011, would require a restudy of the transmission system impacts. A true and correct copy of the letter, dated April 28, 2011, from Exergy is attached hereto as Attachment 37 and incorporated herein by reference.

53. On May 3, 2011, Idaho Power issued a draft Generator Interconnection Facility Study Report for the Deep Creek, Cottonwood, and Rogerson Flats Projects. A true and correct copy of the draft Generator Interconnection Facility Study Report for the Deep Creek, Cottonwood, and Rogerson Flats Projects is attached hereto as Attachment 38 and incorporated herein by reference.

54. On May 20, 2011, Idaho Power sent a letter to Idaho Power explaining the need for a restudy of the transmission system impacts associated with the modifications proposed in the Exergy letter dated April 12, 2011. A true and correct copy of the letter, dated May 20, 2011, from Idaho Power is attached hereto as Attachment 39 and incorporated herein by reference.

55. On June 3, 2011, Exergy sent a letter to Idaho Power that requested that

> Idaho Power's supply department initiate the additional transmission designation steps necessary to deliver to native load the entire 84 MWs for the Deep Creek, Rogerson Flats, Cottonwood, and Salmon Creek wind parks from the point of interconnection on the 345 kV line used in Interconnection Request Nos. 325 and 327.

A true and correct copy of the letter, dated June 3, 2011, from Exergy is attached hereto as Attachment 40 and incorporated herein by reference.

56. On June 7, 2011, Idaho Power issued a Generator Interconnection Facility Study Final Report for the Deep Creek, Cottonwood, and Rogerson Flats Projects. A true and correct copy of the Generator Interconnection Facility Study Final Report for the Deep Creek, Cottonwood, and Rogerson Flats Projects Project is attached hereto as Attachment 41 and incorporated herein by reference.

57. On July 13, 2011, Idaho Power, as transmission customer, submitted to Idaho Power, as transmission provider, new transmission service requests for network resource designation for the Jack Ranch Project.

58. On July 22, 2011, Exergy sent a communication to Idaho Power verifying that "we can withdraw anything that does not have to do with the 345kV interconnect at this time. I do not believe, given the reports, we shall be connecting anything to the 138kV line." A true and correct copy of the email from Exergy, dated July 22, 2011, is attached hereto as Attachment 42 and incorporated herein by reference. Subsequent to receipt of this email, Idaho Power ceased work on the Generation Interconnection Project Queue number of 322 for the Rogerson Flats Project; the Generation Interconnection Project Queue number of 323 for the Cottonwood Project; and the Generation Interconnection Project Queue number of 324 to the Deep Creek Project because Exergy planned to use the Generation Interconnection Project Queue number of 327 for the Jack Ranch Project to interconnect such projects.

59. On August 9, 2011, Idaho Power, as transmission provider, notified Idaho Power, as transmission customer, that a new system impact study would be necessary

for the network transmission service request for the Jack Ranch Project and provided a copy of a transmission system impact study agreement for such study. A true and correct copy of the correspondence from Idaho Power, dated August 9, 2011, is attached hereto as Exhibit 43 and incorporated herein by reference.

60. On August 11, 2011, Idaho Power issued a draft Generator Interconnection Facility Study Report for the Salmon Creek and Jack Ranch Projects. A true and correct copy of the draft Generator Interconnection Facility Study Report for the Salmon Creek and Jack Ranch Projects is attached hereto as Attachment 44 and incorporated herein by reference.

63. On August 17, 2011, Idaho Power informed Exergy that transmission restudies would need to be completed for the additional 4 megawatts (MW) for the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects. A true and correct copy of the correspondence, dated August 17, 2011, is attached hereto as Attachment 45 and incorporated herein by reference.

61. On December 6, 2011, Idaho Power issued a Generator Interconnection Facility Study Final Report for the Salmon Creek and Jack Ranch Projects. A true and correct copy of the Generator Interconnection Facility Study Final Report for the Salmon Creek and Jack Ranch Projects is attached hereto as Attachment 46 and incorporated herein by reference.

62. On December 15, 2011, Idaho Power issued a form Schedule 72 Generator Interconnection Agreement for the Salmon Creek and Jack Ranch Projects. A true and correct copy of the form Schedule 72 Generator Interconnection Agreement

for the Salmon Creek and Jack Ranch Projects is attached hereto as Attachment 47 and incorporated herein by reference.

63. On February 15, 2012, Idaho Power issued a Generator Interconnection Facility Study Revised Final Report for the Salmon Creek and Jack Ranch Projects. A true and correct copy of the Generator Interconnection Facility Study Revised Final Report for the Salmon Creek and Jack Ranch Projects is attached hereto as Attachment 48 and incorporated herein by reference.

64. On April 10, 2012, Idaho Power sent a letter to Exergy that stated that it would not be possible to have the interconnection construction and the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects energized before the end of 2012 because Idaho Power had not yet received an executed Generator Interconnection Agreement or construction funding from Exergy for the projects. A true and correct copy of the letter, dated April 10, 2012, from Idaho Power is attached hereto as Attachment 49 and incorporated herein by reference. Such letter stated as follows: "Idaho Power's estimate of a minimum of 18 months from payment of funds and execution of the GIA to complete the necessary system upgrades and interconnection facilities required to energize your project on Idaho Power's system, and even given the other uncertainties involved, it could take longer than 18 months still." Attachment 49 at p. 2. The letter also included a draft Generator Interconnection Agreement for the Salmon Creek and Jack Ranch Projects. *Id.*

65. On May 9, 2012, Exergy responded to Idaho Power's letter dated April 10, 2012. A true and correct copy of the letter, dated May 9, 2012, from Exergy is attached hereto as Attachment 50 and incorporated herein by reference. Such letter stated that

Exergy sought (i) an in-service date of December 15, 2012, for the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects and (ii) the insertion of a provision in the Generator Interconnection Agreement that would allow Exergy to self-build the interconnection facilities associated with the Salmon Creek and Jack Ranch Projects.

66. On May 14, 2012, Idaho Power responded to Exergy's letter dated May 9, 2012. A true and correct copy of the letter, dated May 14, 2012, from Idaho Power is attached hereto as Attachment 51 and incorporated herein by reference. Such letter reiterated earlier statements that "**it will not be possible to have the interconnection constructed and energized for the Jack Ranch Projects before the end of 2012**." Attachment 51 at p. 1 (emphasis in original). Furthermore, the letter stated that Idaho Power would not agree to Exergy's attempt to unilaterally extend the Scheduled Operation Date for the Projects and that "[f]ailure to achieve an Operation Date within 90 days of June 30, 2012 will be deemed a material breach by you of the FESAs." *Id.* at p. 2. Finally, Idaho Power enclosed a Schedule 72 Generator Interconnection Agreement for the Projects with the letter, dated May 14, 2012, and stated that Exergy must execute and return the agreement with the required deposit by June 13, 2012. *Id.*

67. On June 1, 2012, Exergy sent a letter to Idaho Power requesting that Idaho Power amend Appendix B of the FESAs for the Projects to provide for a Scheduled Operation Date of December 1, 2012. A true and correct copy of the letter, dated June 1, 2012, from Exergy is attached hereto as Attachment 52 and incorporated herein by reference. In such letter, Exergy asserted that "[t]he parties originally agreed to June 30, 2012, as the Scheduled Operation Date because Idaho Power Company

had originally provided the Project Companies with an initial on-line date of December 31, 2011 based on the interconnection studies." Attachment 52 at p. 1.

68. On June 8, 2012, Idaho Power responded to Exergy's letter that requested that Idaho Power amend Appendix B of the FESAs for Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects to provide for a Scheduled Operation Date of December 1, 2012. A true and correct copy of the letter, dated June 8, 2012, from Idaho Power is attached hereto as Attachment 53 and incorporated herein by reference. In its response letter, Idaho Power reiterated that it would not agree to extend the Scheduled Operation Date in the FESAs for Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects. Attachment 53 at p. 1. Such letter further stated that the Scheduled Operation Date of December 2011 was a date selected by Exergy in its Small Generator Interconnection Request for Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects and not a date to which Idaho Power agreed. *Id.* at p. 1-2. Furthermore, the Idaho Power letter, dated June 8, 2012, emphasized that

> Idaho Power communicated to you on multiple occasions, both verbally and in writing, that Exergy was proceeding at is own risk in signing FESAs in December 2010 with a Scheduled Operation Date of June 30, 2012, prior to Idaho Power completing the necessary generator interconnection and transmission studies to determine how long it would take to construct and/or upgrade such facilities as well as the cost of such facilities.

Id.

69. On June 12, 2012, Exergy sent an email to Idaho Power that again requested that Idaho Power insert a provision in the Generator Interconnection Agreement that would allow Exergy to self-build the interconnection facilities associated with the Jack Ranch Project. A true and correct copy of the email, dated June 12, 2012, from Exergy is attached hereto as Attachment 54 and incorporated herein by reference.

70. On June 12, 2012, Idaho Power sent a letter in response to the Exergy email, dated June 12, 2012. A true and correct copy of the letter, dated June 12, 2012, from Idaho Power is attached hereto as Attachment 55 and incorporated herein by reference. In such letter, Idaho Power stated that Idaho Power's Tariff Schedule 72 governs the interconnection agreement between Idaho Power and qualifying facilities and that Schedule 72 expressly provides that Idaho Power "will construct, own, operate and maintain all equipment, Upgrades and Relocations on the Company's electrical side of the Interconnection Point." Attachment 55 at p. 1. Additionally, such letter stated that Idaho Power had included provisions that would allow "Idaho Power to work cooperatively with you and bring to bear the assistance of third-party contractors and other methods to reasonably expedite the required work for your interconnection and upgrades." *Id.* at p. 2.

71. On June 13, 2012, Exergy hand delivered a signed Schedule 72 Generator Interconnection Agreement for the Jack Ranch Project. A true and correct copy of the Schedule 72 Generator Interconnection Agreement for the Jack Ranch Project hand delivered by Exergy on June 13, 2012, is attached hereto as Attachment 56 and incorporated herein by reference. In such agreement, Exergy inserted, without Idaho Power's information or consent, the following provision:

> *8.3 <u>Option to Build</u>. If the dates designated by Seller are not acceptable to Idaho Power, Idaho Power shall so notify Seller within thirty (30) calendar days, and unless the Parties agree otherwise, Seller shall have the option to assume responsibility for the design, procurement and construction of Idaho Power's Interconnection Facilities and any related or necessary Upgrades, Special Facilities, and Network Upgrades.*

Id. at p. 10 (italics in original).

72. On June 13, 2012, counsel for Exergy sent a letter to Idaho Power in response to Idaho Power's letter, dated June 12, 2012. A true and correct copy of the correspondence from Exergy, dated June 13, 2012, is attached hereto as Attachment 57 and incorporated herein by reference. In the letter, counsel for Exergy asserted, among other things, the following:

> Idaho Power's position has placed Exergy in a very difficult position, and may compel Exergy to pursue all available legal and equitable remedies for what amounts to a breach of good faith and fair dealing under Idaho contract law, as well as discriminatory treatment under implementing rules of the Public Utilities Regulatory Policy Act of 1978.

Id. at p. 1.

73. On June 14, 2012, Idaho Power sent a letter to Exergy that stated that Idaho Power had removed the Jack Ranch Project from the interconnection queue as a result of Exergy's failure to execute a Schedule 72 Generator Interconnection Agreement and provide a deposit associated therewith by June 13, 2012. A true and correct copy of the Idaho Power letter, dated June 14, 2012, is attached hereto as Attachment 58 and incorporated herein by reference.

74. On June 15, 2012, counsel for Exergy sent a letter to Idaho Power in response to the Idaho Power letter dated June 14, 2012. A true and correct copy of the letter dated June 15, 2012, from counsel for Exergy is attached hereto as Attachment 59 and incorporated herein by reference. In such letter, counsel for Exergy suggested that the signed Schedule 72 Generator Interconnection Agreement for the Jack Ranch Project that Exergy hand delivered to Idaho Power on June 13, 2012, satisfied Exergy's obligations and that Exergy was willing to post the deposit after Idaho Power had countersigned the agreement:

> You must have realized by now that your statement that "Exergy did not provide Idaho Power an executed copy of the Final GIA, nor was a deposit for the Projects received" is in error. An Exergy employee delivered a signed GIA directly and personally to Mr. Donovan Walker at five minutes of five p.m. on Wednesday the 13th. That GIA was, in fact executed by Mr. Carkulis and Mr. Carkulis is prepared to post the deposit when the agreement is fully executed by Idaho Power.
>
> I therefore respectfully request that you replace these projects to their rightful place in the queue.

Attachment 59 at p. 1.

75. On June 18, 2012, Idaho Power sent a letter in response to the letter dated June 15, 2012, from counsel for Exergy. A true and correct copy of the letter dated June 18, 2012, from Idaho Power is attached hereto as Attachment 60 and incorporated herein by reference. Idaho Power's letter stated that Schedule 72 Generator Interconnection Agreement for the Jack Ranch Project that Exergy hand delivered to Idaho Power on June 13, 2012, contained self-build provisions unilaterally inserted by Exergy and to which Idaho Power could not agree. Attachment 60 at p. 1-2. Therefore, Idaho Power stated that Exergy failed to provide an executed, final Schedule 72 Generator Interconnection Agreement and a deposit by the deadline of June 13, 2012:

> [Exergy] failed to sign and return the Final GIA that was sent to Exergy on May 14, 2012, by the June 13, 2012, deadline. Additionally, [Exergy] did not pay the required deposit by the close of business on June 13, 2012.

Id. at p. 2.

76. On June 28, 2012, Exergy sent a "Notice of Force Majeure" to Idaho Power. A true and correct copy of the Notice of Force Majeure dated June 28, 2012, from Idaho Power is attached hereto as Attachment 61 and incorporated herein by

reference. In its Notice of Force Majeure, Exergy contends, among other things, that Idaho Power's estimated date for construction of interconnection facilities is a Force Majeure event under the FESAs for the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects.

77. On July 3, 2012, Idaho Power sent a letter to Exergy. A true and correct copy of the letter dated July 3,2012, from Idaho Power is attached hereto as Attachment 62 and incorporated herein by reference. In such letter, Idaho Power placed Exergy on notice that if the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects fail "to achieve the Operation Date within ninety (90) days following the Scheduled Operation Date, such failure will be a Material Breach of the FESAs and [Idaho Power] may terminate the FESAs at that time." Attachment 62 at p. 2.

78. On July 10, 2012, counsel for Exergy sent a letter to Idaho Power that asserted that the Schedule 72 Generator Interconnection Agreement for the Salmon Creek and Jack Ranch Projects is subject to the jurisdiction of, and governed by the rules of, the Federal Energy Regulatory Commission ("FERC"). A true and correct copy of the letter dated July 10, 2012, from Idaho Power is attached hereto as Attachment 63 and incorporated herein by reference. Specifically, such letter requests that Idaho Power submit the Schedule 72 Generator Interconnection Agreement for the Salmon Creek and Jack Ranch Projects to FERC for resolution of disputed issues:

> This interconnection is subject to the jurisdiction of, and governed by the rules of, the Federal Energy Regulatory Commission ("FERC"). Therefore, it was inexcusable for Idaho Power to unilaterally terminate negotiations after the parties were unable to agree on an in-service date and Exergy reasonably requested use of a standard term from the LGIA. Instead, Idaho Power should

> have submitted the Unexecuted Generator Interconnection Agreement with FERC for resolution of all disputed issues.
>
> Thus, Exergy requests that Idaho Power immediately file the Unexecuted Generator Interconnection Agreement with FERC for resolution of the disputed issues.

Attachment 63 at p. 1.

79. On July 13, 2012, Exergy sent a letter to Idaho Power that asserted that the Notice of Force Majeure dated June 28, 2012, had resulted in a suspension of all parties' performance under the FESAs for the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects, notwithstanding Idaho Power's position that no event of Force Majeure had occurred or was occurring. A true and correct copy of the letter dated July 13, 2012, from Exergy is attached hereto as Attachment 64 and incorporated herein by reference. In such letter, Exergy stated that disputes with respect to the FESAs for the Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Projects must be submitted to this Commission for resolution pursuant to section 19.1 of the FESA:

> The Notice of Force Majeure previously given and received by Idaho Power is incorporated herein by this reference thereto, in all respects as if fully set forth herein. A suspension of all parties' performance has been put into effect. Idaho Power's disagreement with respect thereto does not affect that suspension. If Idaho Power disputes this, then pursuant to Section 19.1 of the FESAs, Idaho Power is contractually obligated to submit the matter to the Commission for resolution.

Attachment 64 at p. 2.

80. On July 17, 2012, Idaho Power sent a letter to counsel for Exergy responding to Exergy's Notice of Force Majeure dated June 28, 2012, and other claims. A true and correct copy of the letter dated July 17, 2012, from Idaho Power is attached hereto as Attachment 65 and incorporated herein by reference.

81. On July 24, 2012, Idaho Power replied to Exergy's July 10, 2012, request to file the GIA with FERC stating that the GIA was not FERC jurisdictional, but rather jurisdictional to the Idaho Public Utilities Commission. This letter additionally referred Exergy to this filing. A true and correct copy of the letter dated July 24, 2012, is attached hereto as Attachment 66 and incorporated herein by reference.

JURISDICTION

A. The Commission has Jurisdiction over Interpretation and Enforcement of the FESAs and the GIA

82. The Commission has authority to issue declaratory orders pursuant to the Idaho Uniform Declaratory Judgments Act. *Utah Power & Light Co. v. Idaho Pub. Utils. Comm'n*, 112 Idaho 10, 12, 730 P.2d 930, 932 (1987). The Idaho Uniform Declaratory Judgments Act provides for the issuance of a declaratory judgment in a contract dispute "before or after there has been a breach." *Harris v. Cassia County,* 106 Idaho 513, 516–517, 681 P.2d 988, 991 (1984).

83. The Commission has jurisdiction over the interpretation of contracts where the parties have agreed to submit a dispute involving contract interpretation to the Commission. Afton Energy, Inc. v. Idaho Power Co., 111 Idaho 925, 929, 729 P.2d 400, 404 (1986) 929, 729 P.2d at 404 (citing Bunker Hill Co. v. Wash. Water Power Co., 98 Idaho 249, 252, 561 P.2d 391, 394 (1977)).

1. The Commission has Jurisdiction over Interpretation and Enforcement of the FESAs

84. Paragraph 7.7 of the FESAs between Idaho Power and each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek provides for the continuing jurisdiction of the Commission over the Agreement:

> Continuing Jurisdiction of the Commission. This Agreement is a special contract and, as such, the rates, terms and conditions contained in this Agreement will be construed in accordance with Idaho Power Company v. Idaho Public Utilities Commission and Afton Energy, Inc., 107 Idaho 781, 693 P.2d 427 (1984), Idaho Power Company v. Idaho Public Utilities Commission, 107 Idaho 1122, 695 P.2d 1 261 (1985), Afton Energy, Inc. v. Idaho Power Company, 111 Idaho 925, 729 P.2d 400 (1986), Section 210 of the Public Utility Regulatory Policies Act of 1978 and 18 CFR §292.303-308.

Attachment 25 at p. 18.

85. Idaho Power and each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek have also agreed to the Commission's jurisdiction regarding any and all disputes under the FESAs. Paragraph 19.1 of the FESAs further provides that all disputes relating to the Agreement will be submitted to the Commission:

> Disputes – All disputes related to or arising under this Agreement, including, but not limited to, the interpretation of the terms and conditions of this Agreement, will be submitted to the Commission for resolution.

Attachment 25 at p. 25.

86. Each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek has reaffirmed its position that the Commission has jurisdiction with regard to disputes under the FESA. Paragraph 2(i) of the Exergy letter dated July 13, 2012, states as follows:

> If Idaho Power disputes [the claim of Force Majeure], then pursuant to Section 22.1 of the FESA, Idaho Power is contractually obligated to submit the matter to the Commission for resolution.

Attachment 65 at p. 2. Idaho Power agrees that the Commission has jurisdiction to interpret and enforce the FESA pursuant to both the FESA itself and the Idaho Uniform Declaratory Judgments Act.

2. The Commission has Jurisdiction over Interpretation and Enforcement of the GIA

87. FERC has stated that the relevant state authority exercises exclusive jurisdiction over interconnections in which the electric utility must purchase the entire output of the qualifying facility:

> When an electric utility is obligated to interconnect under Section 292.303 of the Commission's Regulations, that is, when it must purchase the QF's total output, the relevant state authority exercises authority over the interconnection and the allocation of interconnection costs.

Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 813 (2003), order on reh 'g, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, order on reh'g, Order No. 2003-B, FERC Stats. & Regs, ¶ 31,171 (2004), order on reh'g, Order No. 2003-C, FERC Stats. & Regs. K 31,190 (2005), aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC, 475 F.3d 1277 (D.C. Cir. 2007)). Recently, FERC has reaffirmed the finding that it will have jurisdiction over an interconnection with a qualifying facility only if the host utility is given notice that third-party sales of the facility's output are occurring or are planned:

> Therefore, consistent with our conclusions in *Niagara Mohawk*, where a host utility is not given notice that third-party sales of output are occurring or are planned (e.g., through a QF's request for wheeling service or a contract providing the QF an express right to sell output to third parties), we will assume that all sales of a QF's output are being made to the host utility and therefore that Commission jurisdiction will not attach.

Florida Power & Light Co., 133 FERC ¶ 61,121 at P 22 (2010) (citing Niagara Mohawk Power Corp., 121 FERC ¶ 61,183 (2007), order denying reh'g, 123 FERC ¶ 61,061 (2008)). Here, the FESAs would obligate Idaho Power to purchase the entire output of the projects. Therefore, this Commission—and not FERC—has jurisdiction over the GIA.

B. <u>The Dispute is a Justiciable Controversy</u>

88. This is an action for declaratory order brought for the purpose of determining a question of actual controversy between the parties. The dispute is as follows: Idaho Power claims that each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek has failed to meet its Scheduled Operation Date of June 30, 2012. Idaho Power further claims that if each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek does not achieve its Operation Date by September 28, 2012, then each entity will be in material breach of its FESA. Each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek disputes Idaho Power's claim that the failure of each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek to achieve the Operation Date will result in material breach of its respective FESA. Specifically, each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek claims Force Majeure events have occurred that excuse its respective failure to meet the Scheduled Operation Date. <u>See</u> Attachment 61. Article XIV of the FESAs excuses both parties from whatever performance is affected by "any cause beyond the control of the Seller or of Idaho Power which, despite the exercise of due diligence, such party is unable to prevent or overcome." Idaho Power disagrees with each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek that any Force Majeure event has occurred. <u>See</u> Attachment 62.

89. As a general rule, a declaratory judgment can only be rendered in a case where an actual or justiciable controversy exists. *Harris,* at 516., citing (internal cites omitted). A "justiciable controversy" ripe for a declaratory judgment must be one that is

appropriate for judicial determination, must be definite and concrete, touching the legal relations of parties having adverse legal interests, and must be real and substantial admitting of specific relief through a decree of a conclusive character, as distinguished from an opinion advising what the law would be upon a hypothetical state of facts. *Harris,* at 516, citing I.C. § 10–1201; Rules Civ.Proc., Rule 57.

90. Idaho Power and each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek agree that the Commission has jurisdiction over the dispute at hand. The dispute is appropriate for the Commission's determination because it requires interpretation of several provisions of the FESAs, as well as Schedule 72 and the generator interconnection process for QF generators. The dispute is definite and concrete because Idaho Power claims current or impending violations of specific provisions of the FESAs by each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek and because Idaho Power disagrees with any application of the Force Majuere provision of the FESAs. The parties to the FESAs have adverse legal interests. The dispute is real and substantial, as distinguished from a request for an advisory opinion, because it 1) involves actions or inactions that have actually occurred, 2) calls for interpretation and enforcement of a valid and enforceable agreement, and 3) the Commission's resolution of the dispute would likely involve specific relief expressly provided for in the FESA.

Declaratory Order To Terminate Contract

91. Idaho Power realleges and hereby incorporates by reference all of the foregoing allegations as if fully stated herein.

A. Idaho Power May Terminate the FESAs Upon Failure of the Projects to Achieve Their Respective Operation Dates

92. Each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek has failed to meet the Scheduled Operation Date of June 30, 2012, as provided in Section B-3 in Appendix B of the FESA. As provided in Section 5.4 of the FESA, the entities will be in material breach of their respective FESA if they fail to achieve the Operation Date by September 28, 2012. The Idaho Uniform Declaratory Judgments Act provides for the issuance of a declaratory judgment in a contract dispute "before or after there has been a breach." *Harris* at 516–517, 991 (1984). Section 5.4 of the each respective FESA provides that upon material breach by Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek, Idaho Power may terminate the FESA at any time. Section 5.3 provides for delay damages as result of a material breach; therefore, in the event of a breach, Idaho Power is entitled to delay damages in the amount provided in Section 5.3 of the FESA. Accordingly, Idaho Power requests an Order from the Commission declaring that Idaho Power may terminate the FESA and recover delay damages upon the failure of each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek to achieve the Operation Date by September 28, 2012.

B. No Force Majuere Event has Occurred

93. Each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek claims that events have occurred that constitute Force Majuere pursuant to Section 14 of the FESA. Paragraph 14.1 states, in relevant part:

> As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the control of the Seller or of Idaho Power which, despite the exercise of due diligence, such Party is unable to prevent or overcome. Force Majeure includes, but is not limited to, acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes and other labor disturbances, earthquakes, fires,

> lightning, epidemics, sabotage, or changes in law or regulation occurring after the Effective Date, which, by the existence of reasonable foresight such party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome.

Attachment 61.

94. In their Notice of Force Majeure, Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek contend that Idaho Power's estimated date for construction of interconnection facilities is a Force Majeure event because the date makes it impossible for them to meet their respective Scheduled Operation Date of June 30, 2012. See Attachment 61.

95. Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek' attempts to excuse their non-performance fails for three reasons: 1) Idaho Power's date for construction of interconnection facilities does not meet the FESA's definition of a Force Majeure event, and 2) Exergy's own actions and/or inactions caused considerable delay that it now claims constitutes forece majeure, and 3) each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek expressly accepted all risks for delays associated with the interconnection process. As defined by this paragraph, an event of Force Majeure must be something that was reasonably unforeseen by the parties. Specifically, Force Majeure events are defined as those that a party "by the exercise of reasonable foresight . . . could not reasonably have been expected to avoid." Here, the risk of delay to the interconnection process was not only foreseeable, but each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek actually considered the risk of delay when it agreed to assume all risks associated with such. Additionally, Exergy has not, to this day, paid the required construction deposit, nor authorized Idaho

Power to move forward with the required work necessary for the interconnection and transmission upgrades required to connect the Projects to Idaho Power's system.

96. On November 17, 2010, Idaho Power wrote to Exergy and expressly advised of the risk of proceeding with obligating the Projects to a Scheduled Operation in the FESAs prior to such time as the interconnection and transmission studies were completed so as to know the anticipated required facilities, the estimated cost, and the estimated construction time required to construct such facilities.

> It was Idaho Power's understanding that Mr. Carkulis wished to get the results of the required interconnection and transmission studies, which will identify the need for and cost of interconnection facilities and possible transmission upgrades, prior to the time at which he would sign a Firm Energy Sales Agreement ("FESA") which would obligate the projects to a Scheduled Operation Date. As you are aware, the FESA contains provisions providing for delay damages should the projects fail to meet the Scheduled Operation Date set forth in the FESA. These delay damages are secured by the requirement to post liquid delay damage security thirty (30) days subsequent to IPUC approval of the FESA. As you are also aware, it is your client's responsibility to work with Idaho Power's Delivery business unit to ensure that sufficient time and resources will be available for Delivery to construct the interconnection facilities, and transmission upgrades if required, in time to allow the projects to achieve the Scheduled Operation Date set forth in the FESA. As Mr. Carkulis has previously been advised, delays in the interconnection or transmission process do not constitute excusable delays in achieving the Scheduled Operation Date, and, if the projects fail to achieve the Scheduled Operation Date at the times specified in the FESA, delay damages will be assessed. It was for this reason that Idaho Power was of the understanding that your client was not yet ready to commit to the execution of a FESA.
>
> If this is not the case, and if your client wishes to proceed forward with the execution of a FESA prior to the completion of the interconnection and transmission studies **and accept the associated risk thereto**, then Idaho Power can send you a draft PURPA Wind FESA that contains the most recent and up-to-date "standard" terms and conditions that have been approved by the IPUC.

Attachment 19 at p. 1-2 (emphasis added).

97. In response to the November 17, 2010 letter, counsel for Exergy confirmed that a delay to the interconnection process was not an excusable delay:

> As you requested, I write to confirm that Exergy, as the developer of [the Jack Ranch Projects], is willing to sign contracts including the standard $45/kw delay liquidated damages clause prior to completion of the entire interconnection and transmission processes for these projects, including Idaho Power internal processes required to designate the resource as a network resource. Exergy understands that, under the current standard contract Idaho Power would agree to enter into, a delay in achieving the online date caused by the interconnection or transmission processes is a delay which will not excuse a possible trigger in the delay damages clause.

Attachment 21. Further, each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek expressly assumed all risk associated with delay related to transmission and interconnection. On November 29, 2010, counsel for Exergy responded to Idaho Power's letter dated November 24, 2010, and emphasized that Exergy accepted the interconnection risks, stating:

> Exergy is fully aware of the contracts' provisions and, as you know has successfully developed many projects using the standard Idaho Power contract. **Exergy is also fully aware of the transmission and interconnection risks, as well as the liquid security provision.**

Attachment 22 (emphasis added). The correspondence discussing the timing of the interconnection process demonstrates that the potential for delay in the interconnection process could have been reasonably foreseen. As a result, the date for construction of the interconnection facilities cannot be an event of Force Majeure under paragraph 14.1 of the FESA. For these reasons, Idaho Power requests an Order from the Commission declaring that no Force Majeure event has occurred to excuse default.

C. Termination of the FESAs is in the Public Interest

98. Idaho Power's ability to terminate the FESAs upon material breach of each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek for failure to meet the Operations Date pursuant to Section 5 of the FESA is in the public interest. The FESA currently provides for rates that have subsequently been found to not be in the public interest. In The Matter of the Commission's Review of PURPA QF Contract Provisions, Case No. GNR-E-11-03, Order No. 32498 at 2 (March 22, 2012), this Commission stated,

> We also find, however, as stated on the record at the conclusion of the March 21, 2012, hearing, that the methodologies previously approved by this Commission, as utilized and applied by Idaho Power, do not currently produce rates that reflect Idaho Power's avoided costs and are not just and reasonable, nor in the public interest. Effective March 21, 2012, and continuing until altered or amended by Order of the Commission at the conclusion of this case, contracts for all projects over 100 kW entered into by Idaho Power and presented to this Commission for approval will be individually evaluated with regard to all terms contained therein.

(Emphasis added). The rates at issue in this Petition are provided in Article VII of the FESA. The FESA's rates have subsequently been determined, as described above, to not be in the public interest. If the Commission issues an order declaring that Idaho Power is authorized to terminate the FESA upon the failure of each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek to meet its Operation Date of September 28, 2012, rates that have been deemed not in the public interest will likewise be terminated. If Idaho Power and each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek were to execute a new FESA, the parties must obviously comply with Order 32498, thereby establishing rates that are in the public interest pursuant to the methodology approved in Order 32498.

REQUESTED RELIEF - CONCLUSION

99. Idaho Power respectfully requests that the Commission grant the following relief:

1) Entry of a declaratory order that the Commission has jurisdiction over the interpretation and enforcement of the FESAs and the GIA;

2) Entry of a declaratory order that Exergy's claim of force majeure does not exist so as to excuse Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek's failure to meet the Scheduled Operation Date;

3) Entry of a declaratory order that each of Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek has failed to place their respective projects in service by the Scheduled Operation Date of June 30, 2012, and that Idaho Power may terminate the FESA as of September 28, 2012, if the Projects fail to achieve their Operation Dates;

4) Entry of a declaratory order stating that, pursuant to the FESAs, Idaho Power is entitled to an award of liquidated damages; and

5) Any further relief to which Idaho Power is entitled.

Respectfully submitted at Boise, Idaho, this 24th day of July 2012.

DONOVAN E. WALKER
Attorney for Idaho Power Company

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that, on this 24th day of July 2012 I served a true and correct copy of IDAHO POWER COMPANY'S PETITION FOR DECLARATORY ORDER upon the following named parties by the method indicated below, and addressed to the following:

Exergy Development Group, LLC	_X_ Hand Delivered
Peter J. Richardson	___ U.S. Mail
RICHARDSON & O'LEARY, PLLC	___ Overnight Mail
515 North 27th Street (83702)	___ FAX
P.O. Box 7218	___ Email peter@richardsonandoleary.com
Boise, Idaho 83707	

Danielle Clark

Danielle Clark, Paralegal

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 1

Rogerson Flats

61322

SMALL GENERATOR INTERCONNECTION REQUEST

(Application Form)

Transmission Provider: IDAHO POWER COMPANY

Designated Contact Person:	Rowena Bishop
Address:	1221 W. Idaho Street, Boise ID 83702
Telephone Number:	208-388-2658
Fax:	208-388-5504
E-Mail Address:	rbishop@idahopower.com

An Interconnection Request is considered complete when it provides all applicable and correct information required below.

Preamble and Instructions

An Interconnection Customers who request interconnection must submit this Interconnection Request by hand delivery, mail, e-mail, or fax to the Transmission Provider.

Processing Fee or Deposit:

If the Interconnection Request passes ALL screens of SGIP Section 2.2.1, the application may be submitted under the Fast Track Process, and the non-refundable processing fee is $500. Please contact Idaho Power if you have any questions.

All Interconnection Requsts submitted under the Study Process, whether a new submission or an Interconnection Request that did not pass the Fast Track Process, shall submit to the Transmission Provider a deposit not to exceed $1,000 towards the cost of the feasibility study.

Interconnection Customer Information

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name: Exergy Development Group of Idaho, LLC

Contact Person: Collin Rudeen

Mailing Address: 802 W Bannock, ste 1200

City: Boise State: ID Zip: 83702

Facility Location (if different from above): N42.2272°, W114.6538°

Telephone (Day): (208) 336-9793 Telephone (Evening): (208) 336-9793

Fax: (208) 336-9431 E-Mail Address: crudeen@exergydevelopment.com

Alternative Contact Information (if different from the Interconnection Customer)

Contact Name: ______________________________

Title: ______________________________

Address: ______________________________

____

Telephone (Day): ______________ Telephone (Evening): ______________

Fax: ______________ E-Mail Address: ______________

Application is for: X New Small Generating Facility
_____ Capacity addition to Existing Small Generating Facility

If capacity addition to existing facility, please describe: ______________________________

Will the Small Generating Facility be used for any of the following?

To Supply Power to the Interconnection Customer? Yes ___ No X
To Supply Power to Others? Yes X No ___

For installations at locations with existing electric service to which the proposed Small Generating Facility will interconnect, provide:

______________________________ ______________________________
(Local Electric Service Provider*) (Existing Account Number*)
[*To be provided by the Interconnection Customer if the local electric service provider is different from the Transmission Provider]

Contact Name: ______________________________

Title: ______________________________

Address: ______________________________

____

Telephone (Day): ______________ Telephone (Evening): ______________

Fax: ______________ E-Mail Address: ______________

Requested Point of Interconnection: N 42.1771°, W 114.6029° (WGS84)

Interconnection Customer's Requested In-Service Date: December, 2011

Small Generating Facility Information
Data apply only to the Small Generating Facility, not the Interconnection Facilities.

Energy Source: ___ Solar X Wind ___ Hydro ___ Hydro Type (e.g. Run-of-River): ___
___ Diesel ___ Natural Gas ___ Fuel Oil ___ Other (state type) ___

Prime Mover: ___ Fuel Cell ___ Recip Engine ___ Gas Turb ___ Steam Turb
___ Microturbine ___ PV ___ Other

Type of Generator: ___ Synchronous X Induction ___ Inverter

Generator Nameplate Rating: 2,050 kW (Typical) Generator Nameplate kVAR: ___

Interconnection Customer or Customer-Site Load: ___ kW (if none, so state)

Typical Reactive Load (if known): ___

Maximum Physical Export Capability Requested: 20,000 kW

List components of the Small Generating Facility equipment package that are currently certified:

Equipment Type	Certifying Entity
1. ___	___
2. ___	___
3. ___	___
4. ___	___
5. ___	___

Is the prime mover compatible with the certified protective relay package? ___ Yes ___ No

Generator (or solar collector)
Manufacturer, Model Name & Number: ___
Version Number: ___

Nameplate Output Power Rating in kW: (Summer) 20,000 (Winter) 20,000
Nameplate Output Power Rating in kVA: (Summer) ___ (Winter) ___

Individual Generator Power Factor
Rated Power Factor: Leading: ___ Lagging: ___

Total Number of Generators in wind farm to be interconnected pursuant to this Interconnection Request: 10 Elevation: 4,960 ft. ___ Single phase X Three phase

Inverter Manufacturer, Model Name & Number (if used): ___

List of adjustable set points for the protective equipment or software: ___

Note: A completed Power Systems Load Flow data sheet must be supplied with the Interconnection Request.

Small Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current: __________ Instantaneous ____ or RMS? ____

Harmonics Characteristics: ____________________

Start-up requirements: ____________________

Small Generating Facility Characteristic Data (for rotating machines)

RPM Frequency: __________
(*) Neutral Grounding Resistor (If Applicable): __________

Synchronous Generators:

Direct Axis Synchronous Reactance, Xd: _______ P.U.
Direct Axis Transient Reactance, X'_d: __________ P.U.
Direct Axis Subtransient Reactance, X''_d: __________ P.U.
Negative Sequence Reactance, X_2: ________ P.U.
Zero Sequence Reactance, X_0: __________ P.U.
KVA Base: ____________________
Field Volts: __________
Field Amperes: __________

Induction Generators:

Motoring Power (kW): __________
I_2^2t or K (Heating Time Constant): __________
Rotor Resistance, Rr: __________
Stator Resistance, Rs: __________
Stator Reactance, Xs: __________
Rotor Reactance, Xr: __________
Magnetizing Reactance, Xm: __________
Short Circuit Reactance, Xd": __________
Exciting Current: __________
Temperature Rise: __________
Frame Size: __________
Design Letter: __________
Reactive Power Required In Vars (No Load): __________
Reactive Power Required In Vars (Full Load): __________
Total Rotating Inertia, H: __________ Per Unit on kVA Base

Note: Please contact the Transmission Provider prior to submitting the Interconnection Request to determine if the specified information above is required.

Excitation and Governor System Data for Synchronous Generators Only

Provide appropriate IEEE model block diagram of excitation system, governor system and power system stabilizer (PSS) in accordance with the regional reliability council criteria. A PSS may be determined to be required by applicable studies. A copy of the manufacturer's block diagram may not be substituted.

Interconnection Facilities Information

Will a transformer be used between the generator and the point of common coupling? X Yes ___No

Will the transformer be provided by the Interconnection Customer? X Yes ___No

Transformer Data (If Applicable, for Interconnection Customer-Owned Transformer):

Is the transformer: ____single phase _____three phase? Size: ___________kVA
Transformer Impedance: _______% on __________kVA Base

If Three Phase:
Transformer Primary: _____ Volts _____ Delta _____Wye _____ Wye Grounded
Transformer Secondary: _____ Volts _____ Delta _____Wye _____ Wye Grounded
Transformer Tertiary: _____ Volts _____ Delta _____Wye _____ Wye Grounded

Transformer Fuse Data (If Applicable, for Interconnection Customer-Owned Fuse):

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: __________________ Type: _______________ Size: ________Speed: ______________

Interconnecting Circuit Breaker (if applicable):

Manufacturer: ____________________________ Type: __________
Load Rating (Amps): _______ Interrupting Rating (Amps): ________ Trip Speed (Cycles): __________

Interconnection Protective Relays (If Applicable):

If Microprocessor-Controlled:

List of Functions and Adjustable Setpoints for the protective equipment or software:

Setpoint Function	Minimum	Maximum
1. ______________________	__________	__________
2. ______________________	__________	__________
3. ______________________	__________	__________
4. ______________________	__________	__________
5. ______________________	__________	__________
6. ______________________	__________	__________

If Discrete Components:

(Enclose Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer: __________ Type: ______ Style/Catalog No.: __________ Proposed Setting: ___________
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Current Transformer Data (If Applicable):

(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer: ____
Type: _______________ Accuracy Class: __ Proposed Ratio Connection: ____

Manufacturer: ____
Type: _______________ Accuracy Class: __ Proposed Ratio Connection: ____

Potential Transformer Data (If Applicable):

Manufacturer: ____
Type: _______________ Accuracy Class: __ Proposed Ratio Connection: ____

Manufacturer: ____
Type: _______________ Accuracy Class: __ Proposed Ratio Connection: ____

General Information

Enclose copy of site electrical one-line diagram showing the configuration of all Small Generating Facility equipment, current and potential circuits, and protection and control schemes. This one-line diagram must be signed and stamped by a licensed Professional Engineer if the Small Generating Facility is larger than 50 kW. Is One-Line Diagram Enclosed? ___Yes X No

Enclose copy of any site documentation that indicates the precise physical location of the proposed Small Generating Facility (e.g., USGS topographic map or other diagram or documentation).

Proposed location of protective interface equipment on property (include address if different from the Interconnection Customer's address) ____________________

Enclose copy of any site documentation that describes and details the operation of the protection and control schemes. Is Available Documentation Enclosed? ___Yes ___No

Enclose copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).
Are Schematic Drawings Enclosed? ___Yes ___No

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request is true and correct.

For Interconnection Customer:

Signed

______________________ Date: 3/12/10

Printed

Collin Rudeen

Jack Ranch

G1 323

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(Application Form)

Transmission Provider: IDAHO POWER COMPANY

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Interconnection Customer Information

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name: Exergy Development Group of Idaho, LLC

Contact Person: Collin Rudeen

Mailing Address: 802 W Bannock, ste 1200

City: Boise State: ID Zip: 83702

Facility Location (if different from above): N 42.2090°, W 114.7053°

Telephone (Day): (208) 336-9793 Telephone (Evening): (208) 336-9793

Fax: (208) 336-9431 E-Mail Address: crudeen@exergydevelopment.com

Alternative Contact Information (if different from the Interconnection Customer)

Contact Name: ______________________________

Title: ______________________________

Address: ______________________________

____

Telephone (Day): ______________ Telephone (Evening): ______________

Fax: ______________ E-Mail Address: ______________

Application is for: X New Small Generating Facility
_____ Capacity addition to Existing Small Generating Facility

If capacity addition to existing facility, please describe: ______________________________

Will the Small Generating Facility be used for any of the following?

To Supply Power to the Interconnection Customer? Yes ___ No X
To Supply Power to Others? Yes X No ___

For installations at locations with existing electric service to which the proposed Small Generating Facility will interconnect, provide:

______________________________ ______________________________
(Local Electric Service Provider*) (Existing Account Number*)
[*To be provided by the Interconnection Customer if the local electric service provider is different from the Transmission Provider]

Contact Name: ______________________________

Title: ______________________________

Address: ______________________________

____

Telephone (Day): ______________ Telephone (Evening): ______________

Fax: ______________ E-Mail Address: ______________

Requested Point of Interconnection: N 42.1771°, W 114.6029° (WGS84)

Interconnection Customer's Requested In-Service Date: December, 2011

Small Generating Facility Information

Data apply only to the Small Generating Facility, not the Interconnection Facilities.

Energy Source: ___ Solar X Wind ___ Hydro ___ Hydro Type (e.g. Run-of-River): ___
___ Diesel ___ Natural Gas ___ Fuel Oil ___ Other (state type) ___

Prime Mover: ___ Fuel Cell ___ Recip Engine ___ Gas Turb ___ Steam Turb
___ Microturbine ___ PV ___ Other

Type of Generator: ___ Synchronous X Induction ___ Inverter

Generator Nameplate Rating: 2,050 kW (Typical) Generator Nameplate kVAR: ___

Interconnection Customer or Customer-Site Load: ___ kW (if none, so state)

Typical Reactive Load (if known): ___

Maximum Physical Export Capability Requested: 20,000 kW

List components of the Small Generating Facility equipment package that are currently certified:

Equipment Type	Certifying Entity
1. ___	___
2. ___	___
3. ___	___
4. ___	___
5. ___	___

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Generator (or solar collector)
Manufacturer, Model Name & Number: ___
Version Number: ___

Nameplate Output Power Rating in kW: (Summer) 20,000 (Winter) 20,000
Nameplate Output Power Rating in kVA: (Summer) ___ (Winter) ___

Individual Generator Power Factor
Rated Power Factor: Leading: ___ Lagging: ___

Total Number of Generators in wind farm to be interconnected pursuant to this Interconnection Request: 10 Elevation: 4,960 ft. ___Single phase X Three phase

Inverter Manufacturer, Model Name & Number (if used): ___

List of adjustable set points for the protective equipment or software: ___

Note: A completed Power Systems Load Flow data sheet must be supplied with the Interconnection Request.

Small Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current: ________ Instantaneous ___ or RMS? ___

Harmonics Characteristics: ________________________________

Start-up requirements: ________________________________

Small Generating Facility Characteristic Data (for rotating machines)

RPM Frequency: ____________
(*) Neutral Grounding Resistor (If Applicable): ___________

Synchronous Generators:

Direct Axis Synchronous Reactance, Xd: _______ P.U.
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KVA Base: ______________________
Field Volts: ____________
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Motoring Power (kW): ____________
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Manufacturer: __________________ Type: _______________ Size: _______Speed: _______________

Interconnecting Circuit Breaker (if applicable):

Manufacturer: ____________________________ Type: __________
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1. ______________________	__________	__________
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If Discrete Components:

(Enclose Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer: __________ Type: ______ Style/Catalog No.: _________ Proposed Setting: ___________
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Manufacturer: ____
Type: ________________ Accuracy Class: __ Proposed Ratio Connection: ____

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Printed

Collin Rudeen

GI 324

JR-1

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List of adjustable set points for the protective equipment or software: ___

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KVA Base: ____________________
Field Volts: ___________
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Induction Generators:

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Potential Transformer Data (If Applicable):

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Type: _______________ Accuracy Class: __ Proposed Ratio Connection: ____

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I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request is true and correct.

For Interconnection Customer:

Signed ______________________ Date: 3/12/10

Printed

Collin Rudeen

· Salmon Creek

GI 325

SMALL GENERATOR INTERCONNECTION REQUEST

(Application Form)

Transmission Provider: IDAHO POWER COMPANY

Designated Contact Person:	Rowena Bishop
Address:	1221 W. Idaho Street, Boise ID 83702
Telephone Number:	208-388-2658
Fax:	208-388-5504
E-Mail Address:	rbishop@idahopower.com

An Interconnection Request is considered complete when it provides all applicable and correct information required below.

Preamble and Instructions

An Interconnection Customers who request interconnection must submit this Interconnection Request by hand delivery, mail, e-mail, or fax to the Transmission Provider.

Processing Fee or Deposit:

If the Interconnection Request passes ALL screens of SGIP Section 2.2.1, the application may be submitted under the Fast Track Process, and the non-refundable processing fee is $500. Please contact Idaho Power if you have any questions.

All Interconnection Requsts submitted under the Study Process, whether a new submission or an Interconnection Request that did not pass the Fast Track Process, shall submit to the Transmission Provider a deposit not to exceed $1,000 towards the cost of the feasibility study.

Interconnection Customer Information

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name: Exergy Development Group of Idaho, LLC

Contact Person: Collin Rudeen

Mailing Address: 802 W. Bannock, ste 1200

City: Boise State: ID Zip: 83702

Facility Location (if different from above): N 42.1967°, W114.6426°

Telephone (Day): (208) 336-9793 Telephone (Evening): (208) 336-9793

Fax: (208) 336-9431 E-Mail Address: crudeen@exergydevelopment.com

Alternative Contact Information (If different from the Interconnection Customer)

Contact Name: ____________________

Title: ____________________

Address: ____________________

____

Telephone (Day): __________ Telephone (Evening): __________

Fax: __________ E-Mail Address: __________

Application is for: X New Small Generating Facility
____ Capacity addition to Existing Small Generating Facility

If capacity addition to existing facility, please describe: ____________________

Will the Small Generating Facility be used for any of the following?

To Supply Power to the Interconnection Customer? Yes ___ No X
To Supply Power to Others? Yes X No ___

For installations at locations with existing electric service to which the proposed Small Generating Facility will interconnect, provide:

____________________ ____________________
(Local Electric Service Provider*) (Existing Account Number*)

[*To be provided by the Interconnection Customer if the local electric service provider is different from the Transmission Provider]

Contact Name: ____________________

Title: ____________________

Address: ____________________

____

Telephone (Day): __________ Telephone (Evening): __________

Fax: __________ E-Mail Address: __________

Requested Point of Interconnection: N 42.1771°, W 114.6029° (WGS84)

Interconnection Customer's Requested In-Service Date: December, 2011

Small Generating Facility Information

Data apply only to the Small Generating Facility, not the Interconnection Facilities.

Energy Source: ___ Solar _X_ Wind ___ Hydro ___ Hydro Type (e.g. Run-of-River): ___
___ Diesel ___ Natural Gas ___ Fuel Oil ___ Other (state type) ___

Prime Mover: ___ Fuel Cell ___ Recip Engine ___ Gas Turb ___ Steam Turb
___ Microturbine ___ PV ___ Other

Type of Generator: ___ Synchronous _X_ Induction ___ Inverter

Generator Nameplate Rating: 2,050 kW (Typical) Generator Nameplate kVAR: ___

Interconnection Customer or Customer-Site Load: ___ kW (if none, so state)

Typical Reactive Load (if known): ___

Maximum Physical Export Capability Requested: 20,000 kW

List components of the Small Generating Facility equipment package that are currently certified:

Equipment Type	Certifying Entity
1. ___	___
2. ___	___
3. ___	___
4. ___	___
5. ___	___

Is the prime mover compatible with the certified protective relay package? ___ Yes ___ No

Generator (or solar collector)
Manufacturer, Model Name & Number: ___
Version Number: ___

Nameplate Output Power Rating in kW: (Summer) 20,000 (Winter) 20,000
Nameplate Output Power Rating in kVA: (Summer) ___ (Winter) ___

Individual Generator Power Factor
Rated Power Factor: Leading: ___ Lagging: ___

Total Number of Generators in wind farm to be interconnected pursuant to this Interconnection Request: 10 Elevation: 4,960 ft. ___ Single phase _X_ Three phase

Inverter Manufacturer, Model Name & Number (if used): ___

List of adjustable set points for the protective equipment or software: ___

Note: A completed Power Systems Load Flow data sheet must be supplied with the Interconnection Request.

Small Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current:__________ Instantaneous ___ or RMS? ___

Harmonics Characteristics:____

Start-up requirements:____

Small Generating Facility Characteristic Data (for rotating machines)

RPM Frequency: ____________
(*) Neutral Grounding Resistor (If Applicable):____________

Synchronous Generators:

Direct Axis Synchronous Reactance, Xd: _______ P.U.
Direct Axis Transient Reactance, X'_d:__________P.U.
Direct Axis Subtransient Reactance, X''_d: ____________P.U.
Negative Sequence Reactance, X_2: ________ P.U.
Zero Sequence Reactance, X_0: __________ P.U.
KVA Base: ______________________
Field Volts: ______________
Field Amperes: ______________

Induction Generators:

Motoring Power (kW): ____________
I_2^2t or K (Heating Time Constant): ____________
Rotor Resistance, Rr: ____________
Stator Resistance, Rs: ____________
Stator Reactance, Xs: ____________
Rotor Reactance, Xr: ____________
Magnetizing Reactance, Xm: ____________
Short Circuit Reactance, Xd": ____________
Exciting Current: ____________
Temperature Rise: ____________
Frame Size: ____________
Design Letter: ____________
Reactive Power Required In Vars (No Load): ____________
Reactive Power Required In Vars (Full Load): ____________
Total Rotating Inertia, H: ____________ Per Unit on kVA Base

Note: Please contact the Transmission Provider prior to submitting the Interconnection Request to determine if the specified information above is required.

Excitation and Governor System Data for Synchronous Generators Only

Provide appropriate IEEE model block diagram of excitation system, governor system and power system stabilizer (PSS) in accordance with the regional reliability council criteria. A PSS may be determined to be required by applicable studies. A copy of the manufacturer's block diagram may not be substituted.

Interconnection Facilities Information

Will a transformer be used between the generator and the point of common coupling? X Yes ___ No

Will the transformer be provided by the Interconnection Customer? X Yes ___ No

Transformer Data (If Applicable, for Interconnection Customer-Owned Transformer):

Is the transformer: ____single phase _____three phase? Size: ___________kVA
Transformer Impedance: _______% on _________kVA Base

If Three Phase:
Transformer Primary: _____ Volts _____ Delta _____Wye _____ Wye Grounded
Transformer Secondary: _____ Volts _____ Delta _____Wye _____ Wye Grounded
Transformer Tertiary: _____ Volts _____ Delta _____Wye _____ Wye Grounded

Transformer Fuse Data (If Applicable, for Interconnection Customer-Owned Fuse):

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: ________________ Type: ______________ Size: _______Speed: ______________

Interconnecting Circuit Breaker (if applicable):

Manufacturer: ___________________________ Type: __________
Load Rating (Amps): _______ Interrupting Rating (Amps): ________ Trip Speed (Cycles): _________

Interconnection Protective Relays (If Applicable):

If Microprocessor-Controlled:

List of Functions and Adjustable Setpoints for the protective equipment or software:

Setpoint Function	Minimum	Maximum
1. ______________	________	________
2. ______________	________	________
3. ______________	________	________
4. ______________	________	________
5. ______________	________	________
6. ______________	________	________

If Discrete Components:

(Enclose Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer: __________ Type: ______ Style/Catalog No.: _________ Proposed Setting: __________
Manufacturer: __________ Type: ______ Style/Catalog No.: _________ Proposed Setting: __________
Manufacturer: __________ Type: ______ Style/Catalog No.: _________ Proposed Setting: __________
Manufacturer: __________ Type: ______ Style/Catalog No.: _________ Proposed Setting: __________
Manufacturer: __________ Type: ______ Style/Catalog No.: _________ Proposed Setting: __________

Current Transformer Data (If Applicable):

(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer: ____
Type: _______________ Accuracy Class: __ Proposed Ratio Connection: ____

Manufacturer: ____
Type: _______________ Accuracy Class: __ Proposed Ratio Connection: ____

Potential Transformer Data (If Applicable):

Manufacturer: ____
Type: _______________ Accuracy Class: __ Proposed Ratio Connection: ____

Manufacturer: ____
Type: _______________ Accuracy Class: __ Proposed Ratio Connection: ____

General Information

Enclose copy of site electrical one-line diagram showing the configuration of all Small Generating Facility equipment, current and potential circuits, and protection and control schemes. This one-line diagram must be signed and stamped by a licensed Professional Engineer if the Small Generating Facility is larger than 50 kW. Is One-Line Diagram Enclosed? ___Yes X No

Enclose copy of any site documentation that indicates the precise physical location of the proposed Small Generating Facility (e.g., USGS topographic map or other diagram or documentation).

Proposed location of protective interface equipment on property (include address if different from the Interconnection Customer's address) ______________________________

Enclose copy of any site documentation that describes and details the operation of the protection and control schemes. Is Available Documentation Enclosed? ___Yes ___No

Enclose copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).
Are Schematic Drawings Enclosed? ___Yes ___No

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request is true and correct.

For Interconnection Customer:

Signed ______________________ Date: 3/12/10

Printed
Collin Rudeen

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 2

RECEIVED 3/15/10 RB

APPENDIX 1 to LGIP
INTERCONNECTION REQUEST FOR A LARGE GENERATING FACILITY

1. The undersigned Interconnection Customer submits this request to interconnect its Large Generating Facility with Transmission Provider's Transmission System pursuant to a Tariff.

2. This Interconnection Request is for (check one):
__X__ A proposed new Large Generating Facility.
_____ An increase in the generating capacity or a Material Modification of an existing Generating Facility.

3. The type of interconnection service requested (check one): 6/3/11 RB - NR designation only
__X__ ~~Energy Resource Interconnection Service~~
__X__ Network Resource Interconnection Service

4. __X__ ~~Check here only if Interconnection Customer requesting Network Resource Interconnection Service also seeks to have its Generating Facility studied for Energy Resource Interconnection Service~~

5. Interconnection Customer provides the following information:

a. Address or location of the proposed new Large Generating Facility site (to the extent known) or, in the case of an existing Generating Facility, the name and specific location of the existing Generating Facility;

Rogerson, ID – see attached map

b. Maximum summer at 34.5 degrees C and winter at -20 degrees C megawatt electrical output of the proposed new Large Generating Facility or the amount of megawatt increase in the generating capacity of an existing Generating Facility;

~~200~~ MW 84 MW 6/3/11 RB

c. General description of the equipment configuration;

Repower 2.0 MW, MM92 wind turbine

d. Commercial Operation Date (Day, Month, and Year);

December, 2011

e. Name, address, telephone number, and e-mail address of Interconnection Customer's contact person;

Collin Rudeen
802 W Bannock, ste 1200
Boise, ID 83702
(208) 336-9793
crudeen@exergydevelopment.com

f. Approximate location of the proposed Point of Interconnection (optional); and

N 42.1771°, W 114.6029° (WGS84)

g. Interconnection Customer Data (set forth in Attachment A)

6. Applicable deposit amount as specified in the LGIP.

7. Evidence of Site Control as specified in the LGIP (check one)

____ Is attached to this Interconnection Request

_X_ Will be provided at a later date in accordance with this LGIP

8. This Interconnection Request shall be submitted to the representative indicated below:

[To be completed by Transmission Provider]

9. Representative of Interconnection Customer to contact:

[To be completed by Interconnection Customer]

10. This Interconnection Request is submitted by:

Name of Interconnection Customer: Exergy Development Group of Idaho

By (signature): ____________________

Name (type or print): Collin Rudeen

Title: Lead Project Engineer

Date: 3/12/2010

Attachment A to Appendix 1
Interconnection Request

LARGE GENERATING FACILITY DATA

UNIT RATINGS

kVA 1667 °F ________ Voltage 575 V
Power Factor
Speed (RPM) Connection (e.g. Wye)
Short Circuit Ratio ________ Frequency, Hertz
Stator Amperes at Rated kVA ________ Field Volts ________
Max Turbine MW 2.0 °F ______

COMBINED TURBINE-GENERATOR-EXCITER INERTIA DATA

Inertia Constant, H =
Moment-of-Inertia, WR^2 = kg.m^2

REACTANCE DATA (PER UNIT-RATED KVA)

	DIRECT AXIS		QUADRATURE AXIS	
Synchronous – saturated	X_{dv}	______	X_{qv}	______
Synchronous – unsaturated	X_{di}	______	X_{qi}	______
Transient – saturated	X'_{dv}	______	X'_{qv}	______
Transient – unsaturated	X'_{di}	______	X'_{qi}	______
Subtransient – saturated	X''_{dv}	______	X''_{qv}	______
Subtransient – unsaturated	X''_{di}	______	X''_{qi}	______
Negative Sequence -- saturated	$X2_v$	______		
Negative Sequence – unsaturated	$X2_i$	______		
Zero Sequence – saturated	$X0_v$	______		
Zero Sequence – unsaturated	$X0_i$	______		
Leakage Reactance	Xl_m	______		

FIELD TIME CONSTANT DATA (SEC)

Open Circuit	T'_{do}	_______	T'_{qo}	_______
Three-Phase Short Circuit Transient	T'_{d3}	_______	T'_{q}	_______
Line to Line Short Circuit Transient	T'_{d2}	_______		
Line to Neutral Short Circuit Transient	T'_{d1}	_______		
Short Circuit Subtransient	T''_{d}	_______	T''_{q}	_______
Open Circuit Subtransient	T''_{do}	_______	T''_{qo}	_______

ARMATURE TIME CONSTANT DATA (SEC)

Three Phase Short Circuit	T_{a3}	_______
Line to Line Short Circuit	T_{a2}	_______
Line to Neutral Short Circuit	T_{a1}	_______

NOTE: If requested information is not applicable, indicate by marking "N/A."

MW CAPABILITY AND PLANT CONFIGURATION LARGE GENERATING FACILITY DATA

ARMATURE WINDING RESISTANCE DATA (PER UNIT)

Positive	R_1	_______
Negative	R_2	_______
Zero	R_0	_______

Rotor Short Time Thermal Capacity I_2^2t = _______

Field Current at Rated kVA, Armature Voltage and PF = ________ amps

Field Current at Rated kVA and Armature Voltage, 0 PF = ________ amps

Three Phase Armature Winding Capacitance = _______ microfarad

Field Winding Resistance = _______ ohms _____ °C

Armature Winding Resistance (Per Phase) = _______ ohms _____ °C

CURVES

Provide Saturation, Vee, Reactive Capability, Capacity Temperature Correction curves. Designate normal and emergency Hydrogen Pressure operating range for multiple curves.

GENERATOR STEP-UP TRANSFORMER DATA RATINGS

Capacity Self-cooled/
Maximum Nameplate
/kVA

Voltage Ratio(Generator Side/System side/Tertiary)
/ /_______________kV

Winding Connections (Low V/High V/Tertiary V (Delta or Wye))
_Y-grounded /Delta/_______________

Fixed Taps Available

Present Tap Setting

IMPEDANCE

Positive Z_1 (on self-cooled kVA rating)___________ % ______ X/R

Zero Z_0 (on self-cooled kVA rating)___________ % ______ X/R

EXCITATION SYSTEM DATA

Identify appropriate IEEE model block diagram of excitation system and power system stabilizer (PSS) for computer representation in power system stability simulations and the corresponding excitation system and PSS constants for use in the model.

GOVERNOR SYSTEM DATA

Identify appropriate IEEE model block diagram of governor system for computer representation in power system stability simulations and the corresponding governor system constants for use in the model.

WIND GENERATORS

Number of generators to be interconnected pursuant to this Interconnection Request: 100

Elevation: 4800' to 6300' _____ Single Phase __X__ Three Phase

Inverter manufacturer, model name, number, and version: REpower MM92

List of adjustable setpoints for the protective equipment or software:

____

Note: A completed General Electric Company Power Systems Load Flow (PSLF) data sheet or other compatible formats, such as IEEE and PTI power flow models, must be supplied with the Interconnection Request. If other data sheets are more appropriate to the proposed device, then they shall be provided and discussed at Scoping Meeting.

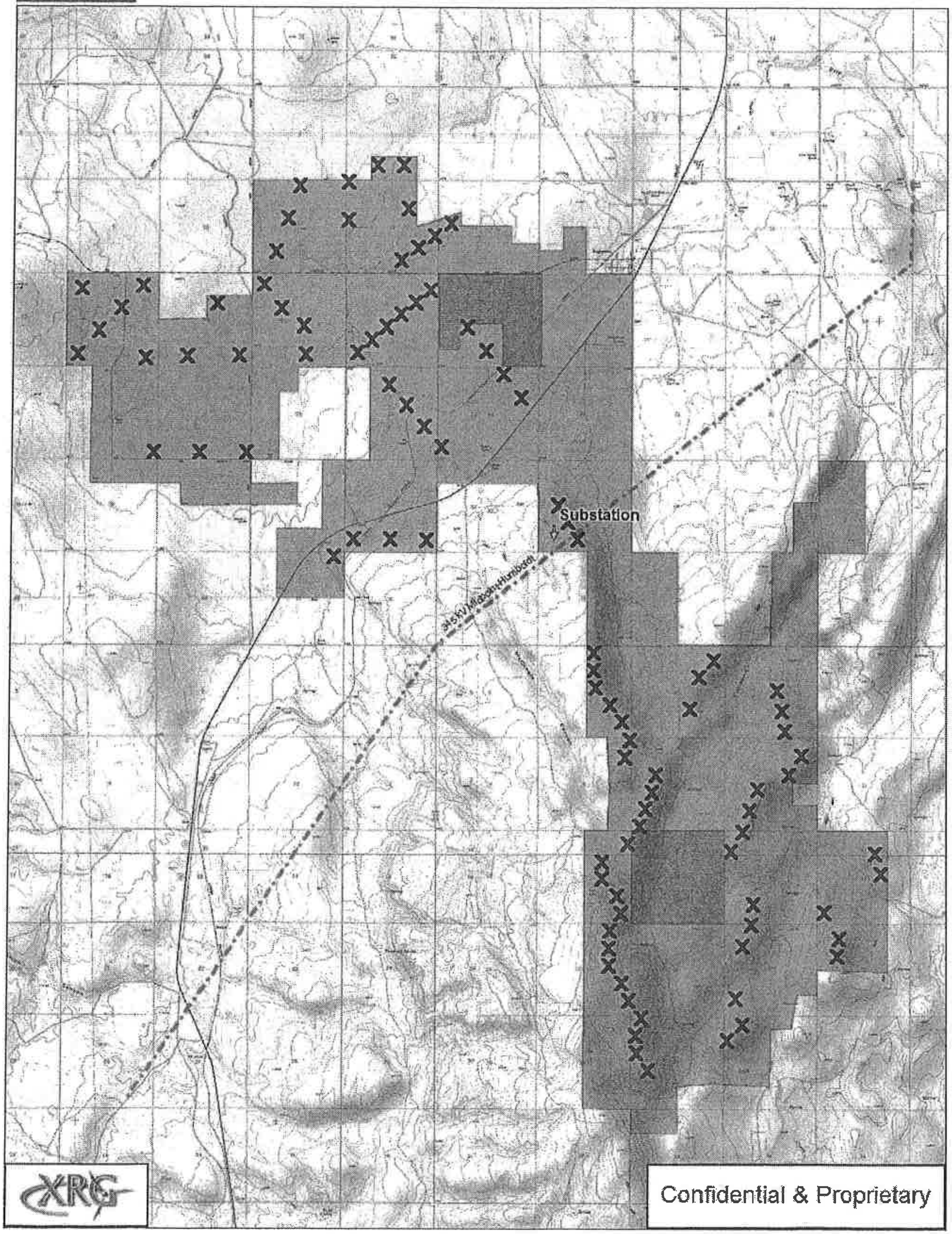
INDUCTION GENERATORS

(*) Field Volts: ________________
(*) Field Amperes: ______________
(*) Motoring Power (kW): ________
(*) Neutral Grounding Resistor (If Applicable): ____________
(*) I_2^2t or K (Heating Time Constant): ____________
(*) Rotor Resistance: ____________
(*) Stator Resistance: ____________
(*) Stator Reactance: _____________
(*) Rotor Reactance: ______________
(*) Magnetizing Reactance: ___________
(*) Short Circuit Reactance: ___________
(*) Exciting Current: ________________
(*) Temperature Rise: ________________
(*) Frame Size: _______________
(*) Design Letter: _____________
(*) Reactive Power Required In Vars (No Load): ________
(*) Reactive Power Required In Vars (Full Load): ________
(*) Total Rotating Inertia, H: ________Per Unit on KVA Base

Note: Please consult Transmission Provider prior to submitting the Interconnection Request to determine if the information designated by (*) is required

327

XMap® 7



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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 3

IDAHO POWER®
An IDACORP Company

March 25, 2010

Randy C. Allphin
Sr. Energy Contract Coordinator
Tel: (208) 388-2614
rallphin@idahopower.com

Exergy Development Group of Idaho
c/o Richardson & O'Leary, PLLC
Attn: Peter Richardson
P.O. Box 7218
Boise, ID 83707

E-mail Copy: peter@richardsonandoleary.com

RE: Letter of Understanding
Rogerson Flats Wind Park, LLC - Proposed Wind Project

Mr. Richardson,

Summarized below is a brief outline of the purchase power agreement, interconnection process and transmission capacity requirements for the proposed Rogerson Flats Wind Park generation project.

Purchase Power Agreement

The project you have described appears to be eligible for a purchase power agreement under the guidelines for a Qualifying Facility as defined by the Public Utilities Regulatory Policies Act of 1978 (PURPA). When your project has met the requirements described below and is therefore eligible for a purchase power agreement, Idaho Power will prepare a purchase power agreement that complies with the current rules and orders that govern these PURPA agreements.

Prior to Idaho Power executing a purchase power agreement it will be required that you have:

1.) Provided documentation that substantiates that the project has filed for interconnection and is in compliance with any payments and/or other requirements specified in the interconnection process applicable to this project and;

2.) Received and accepted an interconnection feasibility study report for this project and;

3.) Returned a signed copy of this letter of understanding and all of the required information to enable Idaho Power to file an application requesting transmission capacity for this project. Completion of the enclosed Transmission Capacity Application Questionnaire will provide the majority of this information and;

4.) Confirmation that the results of the initial transmission capacity application are known and the project accepts these results and intends to continue with the development of the project including, if applicable, execution of a Network Resource Integration Study Agreement in the form enclosed herein.

Interconnection and Transmission Capacity

Your project will be responsible for all costs of physically interconnecting the project to the Idaho Power electrical system and any costs associated with acquiring adequate firm transmission capacity on the Idaho Power transmission system to enable the project's energy to be delivered to Idaho Power customers.

Interconnection

Your project will be required to complete the interconnection process and execute a Generation Interconnection Agreement ("GIA") in accordance with the applicable state and federal requirements.

Transmission Capacity

To sell your project's energy to Idaho Power, your project must be designated as a Network Resource ("DNR").

In order for this project to achieve DNR status, Idaho Power is required to make a request (complete and file an application) and be granted firm transmission capacity from the Idaho Power delivery business unit ("Delivery") to move your project's energy from the physical interconnection point to Idaho Power customers. The project must be granted DNR status no later than 60 days prior to the project delivering any energy to Idaho Power.

Idaho Power will begin this firm transmission capacity application process only after the project has returned a signed copy of this letter of understanding and all of the information required for Idaho Power to file this application (see attached Transmission Capacity Application Questionnaire).

After filing a complete firm transmission capacity application with Delivery, Idaho Power will receive notification back from Delivery within approximately 30 days that: (a) adequate transmission capacity is available for this project without the need to construct upgrades; or (b) a transmission capacity system impact study is required to determine the available transmission capacity and/or required upgrades; or (c) a statement of the required transmission upgrades and the associated costs. Idaho Power will notify the project of this response to the transmission capacity application in a timely manner after the response is received from Delivery.

If the response from Delivery is as specified in item (a) (transmission capacity is available), the project will be required to execute a purchase power agreement with Idaho Power within 30 days in order to retain this transmission capacity reservation.

If the response from Delivery is as specified in items (b) or (c) (studies required and/or upgrades required), the project will be required to execute a Network Resource Integration Study Agreement (sample copy attached for your information) and submit all required deposits or fees within 15 days after receiving notification of this requirement in order for Idaho Power to continue the transmission capacity request process. This Network Resource Integration Study Agreement will specify that the project will be responsible for costs incurred by Idaho Power to perform any required studies. If, after the studies are concluded and the costs of upgrades (if any) are known, and the project wishes to continue the pursuit of transmission capacity, the project will also be responsible for all transmission system upgrade costs identified within the studies. The fees and costs will be in the form of both initial deposits as well as actual costs. If at any time after executing the Network Resource Integration Study Agreement the project does not pay any required fees, or elects to stop the transmission study or upgrade process, the project shall be responsible for all costs incurred by Idaho Power in performing the studies or upgrades up to the point of termination of the Network Resource Integration Study Agreement.

Upon successful completion of the above described transmission capacity upgrade study process, a transmission capacity reservation will exist for this project. However, in order to finalize this transmission capacity reservation, a purchase power agreement with Idaho Power must be executed no later than 30 days after the transmission capacity upgrades studies are completed. If the purchase power agreement is not executed by this deadline, the transmission capacity reservation will be released and this process will have to be repeated if the project later requests transmission capacity.

As noted earlier, this transmission capacity acquisition and receipt of the associated Network Resource designation must be completed, at the minimum, 60 days prior to the project delivering any energy to Idaho Power. In addition, the project must provide routine updates to Idaho Power of the expected online date of the generation project to ensure Idaho Power is capable of accepting the energy from the project on the actual date the project comes online.

P O Box 70 Boise, Idaho 83707 1221 W Idaho St. Boise, Idaho 83702

Please return all required information to:

Idaho Power Company
Attn: Randy C. Allphin
P O Box 70
Boise, ID 83707
E-mail: rallphin@idahopower.com

Sincerely,

Randy C Allphin
Idaho Power Company

Understood and accepted this ____ day of __________________, 2010

Signature ____

Print Name ____

Title ____

IDAHO POWER®
An IDACORP Company

March 25, 2010

Randy C. Allphin
Sr. Energy Contract Coordinator
Tel: (208) 388-2614
rallphin@idahopower.com

Exergy Development Group of Idaho
c/o Richardson & O'Leary, PLLC
Attn: Peter Richardson
P.O. Box 7218
Boise, ID 83707

E-mail Copy: peter@richardsonandoleary.com

RE: Letter of Understanding
Jack Ranch Wind Park, LLC - Proposed Wind Project

Mr. Richardson,

Summarized below is a brief outline of the purchase power agreement, interconnection process and transmission capacity requirements for the proposed Jack Ranch Wind Park generation project.

Purchase Power Agreement

The project you have described appears to be eligible for a purchase power agreement under the guidelines for a Qualifying Facility as defined by the Public Utilities Regulatory Policies Act of 1978 (PURPA). When your project has met the requirements described below and is therefore eligible for a purchase power agreement, Idaho Power will prepare a purchase power agreement that complies with the current rules and orders that govern these PURPA agreements.

Prior to Idaho Power executing a purchase power agreement it will be required that you have:

1.) Provided documentation that substantiates that the project has filed for interconnection and is in compliance with any payments and/or other requirements specified in the interconnection process applicable to this project and;

2.) Received and accepted an interconnection feasibility study report for this project and;

3.) Returned a signed copy of this letter of understanding and all of the required information to enable Idaho Power to file an application requesting transmission capacity for this project. Completion of the enclosed Transmission Capacity Application Questionnaire will provide the majority of this information and;

4.) Confirmation that the results of the initial transmission capacity application are known and the project accepts these results and intends to continue with the development of the project including, if applicable, execution of a Network Resource Integration Study Agreement in the form enclosed herein.

Interconnection and Transmission Capacity

Your project will be responsible for all costs of physically interconnecting the project to the Idaho Power electrical system and any costs associated with acquiring adequate firm transmission capacity on the Idaho Power transmission system to enable the project's energy to be delivered to Idaho Power customers.

Interconnection

Your project will be required to complete the interconnection process and execute a Generation Interconnection Agreement ("GIA") in accordance with the applicable state and federal requirements.

Transmission Capacity

To sell your project's energy to Idaho Power, your project must be designated as a Network Resource ("DNR").

In order for this project to achieve DNR status, Idaho Power is required to make a request (complete and file an application) and be granted firm transmission capacity from the Idaho Power delivery business unit ("Delivery") to move your project's energy from the physical interconnection point to Idaho Power customers. The project must be granted DNR status no later than 60 days prior to the project delivering any energy to Idaho Power.

Idaho Power will begin this firm transmission capacity application process only after the project has returned a signed copy of this letter of understanding and all of the information required for Idaho Power to file this application (see attached Transmission Capacity Application Questionnaire).

After filing a complete firm transmission capacity application with Delivery, Idaho Power will receive notification back from Delivery within approximately 30 days that: (a) adequate transmission capacity is available for this project without the need to construct upgrades; or (b) a transmission capacity system impact study is required to determine the available transmission capacity and/or required upgrades; or (c) a statement of the required transmission upgrades and the associated costs. Idaho Power will notify the project of this response to the transmission capacity application in a timely manner after the response is received from Delivery.

P O Box 70 Boise, Idaho 83707 1221 W Idaho St. Boise, Idaho 83702

If the response from Delivery is as specified in item (a) (transmission capacity is available), the project will be required to execute a purchase power agreement with Idaho Power within 30 days in order to retain this transmission capacity reservation.

If the response from Delivery is as specified in items (b) or (c) (studies required and/or upgrades required), the project will be required to execute a Network Resource Integration Study Agreement (sample copy attached for your information) and submit all required deposits or fees within 15 days after receiving notification of this requirement in order for Idaho Power to continue the transmission capacity request process. This Network Resource Integration Study Agreement will specify that the project will be responsible for costs incurred by Idaho Power to perform any required studies. If, after the studies are concluded and the costs of upgrades (if any) are known, and the project wishes to continue the pursuit of transmission capacity, the project will also be responsible for all transmission system upgrade costs identified within the studies. The fees and costs will be in the form of both initial deposits as well as actual costs. If at any time after executing the Network Resource Integration Study Agreement the project does not pay any required fees, or elects to stop the transmission study or upgrade process, the project shall be responsible for all costs incurred by Idaho Power in performing the studies or upgrades up to the point of termination of the Network Resource Integration Study Agreement.

Upon successful completion of the above described transmission capacity upgrade study process, a transmission capacity reservation will exist for this project. However, in order to finalize this transmission capacity reservation, a purchase power agreement with Idaho Power must be executed no later than 30 days after the transmission capacity upgrades studies are completed. If the purchase power agreement is not executed by this deadline, the transmission capacity reservation will be released and this process will have to be repeated if the project later requests transmission capacity.

As noted earlier, this transmission capacity acquisition and receipt of the associated Network Resource designation must be completed, at the minimum, 60 days prior to the project delivering any energy to Idaho Power. In addition, the project must provide routine updates to Idaho Power of the expected online date of the generation project to ensure Idaho Power is capable of accepting the energy from the project on the actual date the project comes online.

Please return all required information to:

Idaho Power Company
Attn: Randy C. Allphin
P O Box 70
Boise, ID 83707
E-mail: rallphin@idahopower.com

Sincerely,

R C. Allp

Randy C Allphin
Idaho Power Company

Understood and accepted this ____ day of __________________, 2010

Signature ____

Print Name ____

Title ____

IDAHO POWER®
An IDACORP Company

March 25, 2010

Randy C. Allphin
Sr. Energy Contract Coordinator
Tel: (208) 388-2614
rallphin@idahopower.com

Exergy Development Group of Idaho
c/o Richardson & O'Leary, PLLC
Attn: Peter Richardson
P.O. Box 7218
Boise, ID 83707

E-mail Copy: peter@richardsonandoleary.com

RE: Letter of Understanding
JR-1, LLC - Proposed Wind Project

Mr. Richardson,

Summarized below is a brief outline of the purchase power agreement, interconnection process and transmission capacity requirements for the proposed JR-1 generation project.

Purchase Power Agreement

The project you have described appears to be eligible for a purchase power agreement under the guidelines for a Qualifying Facility as defined by the Public Utilities Regulatory Policies Act of 1978 (PURPA). When your project has met the requirements described below and is therefore eligible for a purchase power agreement, Idaho Power will prepare a purchase power agreement that complies with the current rules and orders that govern these PURPA agreements.

Prior to Idaho Power executing a purchase power agreement it will be required that you have:

1.) Provided documentation that substantiates that the project has filed for interconnection and is in compliance with any payments and/or other requirements specified in the interconnection process applicable to this project and;

2.) Received and accepted an interconnection feasibility study report for this project and;

3.) Returned a signed copy of this letter of understanding and all of the required information to enable Idaho Power to file an application requesting transmission capacity for this project. Completion of the enclosed Transmission Capacity Application Questionnaire will provide the majority of this information and;

4.) Confirmation that the results of the initial transmission capacity application are known and the project accepts these results and intends to continue with the development of the project including, if applicable, execution of a Network Resource Integration Study Agreement in the form enclosed herein.

Interconnection and Transmission Capacity

Your project will be responsible for all costs of physically interconnecting the project to the Idaho Power electrical system and any costs associated with acquiring adequate firm transmission capacity on the Idaho Power transmission system to enable the project's energy to be delivered to Idaho Power customers.

Interconnection

Your project will be required to complete the interconnection process and execute a Generation Interconnection Agreement ("GIA") in accordance with the applicable state and federal requirements.

Transmission Capacity

To sell your project's energy to Idaho Power, your project must be designated as a Network Resource ("DNR").

In order for this project to achieve DNR status, Idaho Power is required to make a request (complete and file an application) and be granted firm transmission capacity from the Idaho Power delivery business unit ("Delivery") to move your project's energy from the physical interconnection point to Idaho Power customers. The project must be granted DNR status no later than 60 days prior to the project delivering any energy to Idaho Power.

Idaho Power will begin this firm transmission capacity application process only after the project has returned a signed copy of this letter of understanding and all of the information required for Idaho Power to file this application (see attached Transmission Capacity Application Questionnaire).

After filing a complete firm transmission capacity application with Delivery, Idaho Power will receive notification back from Delivery within approximately 30 days that: (a) adequate transmission capacity is available for this project without the need to construct upgrades; or (b) a transmission capacity system impact study is required to determine the available transmission capacity and/or required upgrades; or (c) a statement of the required transmission upgrades and the associated costs. Idaho Power will notify the project of this response to the transmission capacity application in a timely manner after the response is received from Delivery.

P O Box 70 Boise, Idaho 83707 1221 W Idaho St. Boise, Idaho 83702

If the response from Delivery is as specified in item (a) (transmission capacity is available), the project will be required to execute a purchase power agreement with Idaho Power within 30 days in order to retain this transmission capacity reservation.

If the response from Delivery is as specified in items (b) or (c) (studies required and/or upgrades required), the project will be required to execute a Network Resource Integration Study Agreement (sample copy attached for your information) and submit all required deposits or fees within 15 days after receiving notification of this requirement in order for Idaho Power to continue the transmission capacity request process. This Network Resource Integration Study Agreement will specify that the project will be responsible for costs incurred by Idaho Power to perform any required studies. If, after the studies are concluded and the costs of upgrades (if any) are known, and the project wishes to continue the pursuit of transmission capacity, the project will also be responsible for all transmission system upgrade costs identified within the studies. The fees and costs will be in the form of both initial deposits as well as actual costs. If at any time after executing the Network Resource Integration Study Agreement the project does not pay any required fees, or elects to stop the transmission study or upgrade process, the project shall be responsible for all costs incurred by Idaho Power in performing the studies or upgrades up to the point of termination of the Network Resource Integration Study Agreement.

Upon successful completion of the above described transmission capacity upgrade study process, a transmission capacity reservation will exist for this project. However, in order to finalize this transmission capacity reservation, a purchase power agreement with Idaho Power must be executed no later than 30 days after the transmission capacity upgrades studies are completed. If the purchase power agreement is not executed by this deadline, the transmission capacity reservation will be released and this process will have to be repeated if the project later requests transmission capacity.

As noted earlier, this transmission capacity acquisition and receipt of the associated Network Resource designation must be completed, at the minimum, 60 days prior to the project delivering any energy to Idaho Power. In addition, the project must provide routine updates to Idaho Power of the expected online date of the generation project to ensure Idaho Power is capable of accepting the energy from the project on the actual date the project comes online.

P O Box 70 Boise, Idaho 83707 1221 W Idaho St. Boise, Idaho 83702

Please return all required information to:

Idaho Power Company
Attn: Randy C. Allphin
P O Box 70
Boise, ID 83707
E-mail: rallphin@idahopower.com

Sincerely,

Randy C Allphin
Idaho Power Company

Understood and accepted this ____ day of __________________, 2010

Signature ____

Print Name ____

Title ____

IDAHO POWER®
An IDACORP Company

March 25, 2010

Randy C. Allphin
Sr. Energy Contract Coordinator
Tel: (208) 388-2614
rallphin@idahopower.com

Exergy Development Group of Idaho
c/o Richardson & O'Leary, PLLC
Attn: Peter Richardson
P.O. Box 7218
Boise, ID 83707

E-mail Copy: peter@richardsonandoleary.com

RE: Letter of Understanding
Salmon Creek Wind Park, LLC - Proposed Wind Project

Mr. Richardson,

Summarized below is a brief outline of the purchase power agreement, interconnection process and transmission capacity requirements for the proposed Salmon Creek Wind Park generation project.

Purchase Power Agreement

The project you have described appears to be eligible for a purchase power agreement under the guidelines for a Qualifying Facility as defined by the Public Utilities Regulatory Policies Act of 1978 (PURPA). When your project has met the requirements described below and is therefore eligible for a purchase power agreement, Idaho Power will prepare a purchase power agreement that complies with the current rules and orders that govern these PURPA agreements.

Prior to Idaho Power executing a purchase power agreement it will be required that you have:

1.) Provided documentation that substantiates that the project has filed for interconnection and is in compliance with any payments and/or other requirements specified in the interconnection process applicable to this project and;

2.) Received and accepted an interconnection feasibility study report for this project and;

3.) Returned a signed copy of this letter of understanding and all of the required information to enable Idaho Power to file an application requesting transmission capacity for this project. Completion of the enclosed Transmission Capacity Application Questionnaire will provide the majority of this information and;

4.) Confirmation that the results of the initial transmission capacity application are known and the project accepts these results and intends to continue with the development of the project including, if applicable, execution of a Network Resource Integration Study Agreement in the form enclosed herein.

Interconnection and Transmission Capacity

Your project will be responsible for all costs of physically interconnecting the project to the Idaho Power electrical system and any costs associated with acquiring adequate firm transmission capacity on the Idaho Power transmission system to enable the project's energy to be delivered to Idaho Power customers.

Interconnection

Your project will be required to complete the interconnection process and execute a Generation Interconnection Agreement ("GIA") in accordance with the applicable state and federal requirements.

Transmission Capacity

To sell your project's energy to Idaho Power, your project must be designated as a Network Resource ("DNR").

In order for this project to achieve DNR status, Idaho Power is required to make a request (complete and file an application) and be granted firm transmission capacity from the Idaho Power delivery business unit ("Delivery") to move your project's energy from the physical interconnection point to Idaho Power customers. The project must be granted DNR status no later than 60 days prior to the project delivering any energy to Idaho Power.

Idaho Power will begin this firm transmission capacity application process only after the project has returned a signed copy of this letter of understanding and all of the information required for Idaho Power to file this application (see attached Transmission Capacity Application Questionnaire).

After filing a complete firm transmission capacity application with Delivery, Idaho Power will receive notification back from Delivery within approximately 30 days that: (a) adequate transmission capacity is available for this project without the need to construct upgrades; or (b) a transmission capacity system impact study is required to determine the available transmission capacity and/or required upgrades; or (c) a statement of the required transmission upgrades and the associated costs. Idaho Power will notify the project of this response to the transmission capacity application in a timely manner after the response is received from Delivery.

P O Box 70 Boise, Idaho 83707 1221 W Idaho St. Boise, Idaho 83702

If the response from Delivery is as specified in item (a) (transmission capacity is available), the project will be required to execute a purchase power agreement with Idaho Power within 30 days in order to retain this transmission capacity reservation.

If the response from Delivery is as specified in items (b) or (c) (studies required and/or upgrades required), the project will be required to execute a Network Resource Integration Study Agreement (sample copy attached for your information) and submit all required deposits or fees within 15 days after receiving notification of this requirement in order for Idaho Power to continue the transmission capacity request process. This Network Resource Integration Study Agreement will specify that the project will be responsible for costs incurred by Idaho Power to perform any required studies. If, after the studies are concluded and the costs of upgrades (if any) are known, and the project wishes to continue the pursuit of transmission capacity, the project will also be responsible for all transmission system upgrade costs identified within the studies. The fees and costs will be in the form of both initial deposits as well as actual costs. If at any time after executing the Network Resource Integration Study Agreement the project does not pay any required fees, or elects to stop the transmission study or upgrade process, the project shall be responsible. for all costs incurred by Idaho Power in performing the studies or upgrades up to the point of termination of the Network Resource Integration Study Agreement.

Upon successful completion of the above described transmission capacity upgrade study process, a transmission capacity reservation will exist for this project. However, in order to finalize this transmission capacity reservation, a purchase power agreement with Idaho Power must be executed no later than 30 days after the transmission capacity upgrades studies are completed. If the purchase power agreement is not executed by this deadline, the transmission capacity reservation will be released and this process will have to be repeated if the project later requests transmission capacity.

As noted earlier, this transmission capacity acquisition and receipt of the associated Network Resource designation must be completed, at the minimum, 60 days prior to the project delivering any energy to Idaho Power. In addition, the project must provide routine updates to Idaho Power of the expected online date of the generation project to ensure Idaho Power is capable of accepting the energy from the project on the actual date the project comes online.

P O Box 70 Boise, Idaho 83707 1221 W Idaho St. Boise, Idaho 83702

Please return all required information to:

Idaho Power Company
Attn: Randy C. Allphin
P O Box 70
Boise, ID 83707
E-mail: rallphin@idahopower.com

Sincerely,

R C Allphin

Randy C Allphin
Idaho Power Company

Understood and accepted this ____ day of ____________________, 2010

Signature ____

Print Name ____

Title ____

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 4

IDAHO POWER®
An IDACORP Company

via certified mail #7008 1300 0000 8876 5605

May 13, 2010

Mr. Collin Rudeen
Exergy Development Group of Idaho LLC
802 West Bannock, Suite 1200
Boise, ID 83702

Re: Project #327, Jack Ranch

Dear Mr. Rudeen:

Enclosed is a signed Feasibility Study Agreement for the above-referenced generator interconnection project. Please provide any technical data required for the study, if you have not already done so. Please review the Point of Interconnection, sign, and return all pages to Candace Gentry, 1221 West Idaho Street, Boise, ID 83702.

We must receive the executed Feasibility Study Agreement from you by 30 calendar days from receipt of this letter, otherwise your application will be deemed withdrawn.

Sincerely,

Orlando L Ciniglio

Orlando Ciniglio
Leader, System Planning Engineering
208.388.2248
ociniglio@idahopower.com

Enclosure: Two Signed Feasibility Study Agreements (one for your records)

C: R Bishop/IPC

P.O. Box 70 (83707)
1221 W. Idaho St.
Boise, ID 83702

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 5

IDAHO POWER®
An IDACORP Company

May 14, 2010

via certified mail #7008 1300 0000 8876 5568

Mr. Collin Rudeen
802 W. Bannock, Suite 1200
Boise, ID 83702

Re: Project #s 322, 323, 324, 325

Dear Mr. Rudeen:

Enclosed are signed Feasibility Study Agreements for the above-referenced generator interconnection projects. Please provide any technical data required for the studies, if you have not already done so. Please review the Point of Interconnection, sign, and return all pages to Candace Gentry, 1221 West Idaho Street, Boise, ID 83702.

We must receive the executed Feasibility Study Agreements from you by 30 business days from receipt of this letter, otherwise your application will be deemed withdrawn.

Sincerely,

Marc Patterson

Marc Patterson
Engineering Leader, T&D Planning
Ph 208.388.2712
marcpatterson@idahopower.com

Enclosure: Two Signed Feasibility Study Agreements (one for your records) for project numbers: 322, 323, 324, and 325
C: R Bishop/IPC

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 6

Feasibility Study Agreement

THIS AGREEMENT is made and entered into this 19th day of MAY 2010, by and between EXERGY DEVELOPMENT GROUP OF IDAHO, a LLC organized and existing under the laws of the State of IDAHO, ("Interconnection Customer,") and Idaho Power Company a Corporation existing under the laws of the State of Idaho ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by Interconnection Customer on March 10, 2010; also known as Project # 322; and

WHEREAS, Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System; and

WHEREAS, Interconnection Customer has requested the Transmission Provider to perform a feasibility study to assess the feasibility of interconnecting the proposed Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed an interconnection feasibility study consistent the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of the feasibility study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The feasibility study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, as may be modified as the result of the scoping meeting. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the feasibility study and as designated in accordance with the standard Small Generator Interconnection Procedures. If the Interconnection Customer modifies its Interconnection Request, the time to complete the feasibility study may be extended by agreement of the Parties.

5.0 In performing the study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Customer shall not be charged for such existing studies; however, the Interconnection Customer shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the feasibility study.

6.0 The feasibility study report shall provide the following analyses for the purpose of identifying any potential adverse system impacts that would result from the interconnection of the Small Generating Facility as proposed:

6.1 Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

6.2 Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;

6.3 Initial review of grounding requirements and electric system protection; and

6.4 Description and non-bonding estimated cost of facilities required to interconnect the proposed Small Generating Facility and to address the identified short circuit and power flow issues.

7.0 The feasibility study shall model the impact of the Small Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Small Generating Facility is being installed.

8.0 The study shall include the feasibility of any interconnection at a proposed project site where there could be multiple potential Points of Interconnection, as requested by the Interconnection Customer and at the Interconnection Customer's cost.

9.0 In lieu of Feasibility Study deposit, Interconnection Customer agrees that study funds will be drawn from the application fee for the performance of the Interconnection Feasibility Study.

Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Feasibility Study. Any difference between the deposit and the actual cost of the study shall be paid by or refunded to Interconnection Customer, as appropriate.

10.0 Once the feasibility study is completed, a feasibility study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the feasibility study must be completed and the feasibility study report transmitted within 30 business days of the Interconnection Customer's agreement to conduct a feasibility study.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

Transmission Provider:
Idaho Power Company – Delivery

Signed: Marc Patterson

Printed: Marc Patterson

Title: Engineering Leader, T&D Planning

Date: May 14, 2010

Interconnection Customer:
EYERGY DEVELOPMENT GROUP OF IDAHO

Signed [signature]

Printed JAMES T. CARKULIS

Title MANAGING MEMBER.

Date 5/19/2010

Attachment A to Feasibility Study Agreement

Assumptions Used in Conducting the Feasibility Study

The feasibility study will be based upon the information set forth in the Interconnection Request and agreed upon in the scoping meeting held on April 27, 2010:

1) Designation of Point of Interconnection and configuration to be studied.

Connecting at 138 kV to the Salmon-Wells line approximately 2 miles south of Rogerson, Idaho and approximately 6 miles west.

2) Designation of alternative Points of Interconnection and configuration.

____

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

Feasibility Study Agreement

THIS AGREEMENT is made and entered into this 19th day of MAY 2010 by and between ENERGY DEVELOPMENT GROUP OF IDAHO a LLC organized and existing under the laws of the State of IDAHO, ("Interconnection Customer,") and Idaho Power Company a Corporation existing under the laws of the State of Idaho ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by Interconnection Customer on March 15, 2010; also known as Project # 323; and

WHEREAS, Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System; and

WHEREAS, Interconnection Customer has requested the Transmission Provider to perform a feasibility study to assess the feasibility of interconnecting the proposed Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed an interconnection feasibility study consistent the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of the feasibility study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The feasibility study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, as may be modified as the result of the scoping meeting. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the feasibility study and as designated in accordance with the standard Small Generator Interconnection Procedures. If the Interconnection Customer modifies its Interconnection Request, the time to complete the feasibility study may be extended by agreement of the Parties.

5.0 In performing the study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Customer shall not be charged for such existing studies; however, the Interconnection Customer shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the feasibility study.

6.0 The feasibility study report shall provide the following analyses for the purpose of identifying any potential adverse system impacts that would result from the interconnection of the Small Generating Facility as proposed:

6.1 Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

6.2 Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;

6.3 Initial review of grounding requirements and electric system protection; and

6.4 Description and non-bonding estimated cost of facilities required to interconnect the proposed Small Generating Facility and to address the identified short circuit and power flow issues.

7.0 The feasibility study shall model the impact of the Small Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Small Generating Facility is being installed.

8.0 The study shall include the feasibility of any interconnection at a proposed project site where there could be multiple potential Points of Interconnection, as requested by the Interconnection Customer and at the Interconnection Customer's cost.

9.0 In lieu of Feasibility Study deposit, Interconnection Customer agrees that study funds will be drawn from the application fee for the performance of the Interconnection Feasibility Study.

Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Feasibility Study. Any difference between the deposit and the actual cost of the study shall be paid by or refunded to Interconnection Customer, as appropriate.

10.0 Once the feasibility study is completed, a feasibility study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the feasibility study must be completed and the feasibility study report transmitted within 30 business days of the Interconnection Customer's agreement to conduct a feasibility study.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

Transmission Provider:
Idaho Power Company – Delivery

Signed: Marc Patterson

Printed: Marc Patterson

Title: Engineering Leader, T&D Planning

Date: May 14, 2010

Interconnection Customer:
EXERGY DEVELOPMENT GROUP OF IDAHO

Signed

Printed JAMES T. CARKULIS

Title MANAGING MEMBER

Date 5/19/2010

Attachment A to Feasibility Study Agreement

Assumptions Used in Conducting the Feasibility Study

The feasibility study will be based upon the information set forth in the Interconnection Request and agreed upon in the scoping meeting held on April 27, 2010:

1) Designation of Point of Interconnection and configuration to be studied.

Connecting at 138 kV to the Salmon-Wells line approximately 2 miles south of Rogerson, Idaho and approximately 6 miles west.

2) Designation of alternative Points of Interconnection and configuration.

____

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

Feasibility Study Agreement

THIS AGREEMENT is made and entered into this 19th day of MAY 2010 by and between EXERGY DEVELOPMENT GROUP OF IDAHO, a LLC organized and existing under the laws of the State of IDAHO, ("Interconnection Customer,") and Idaho Power Company a Corporation existing under the laws of the State of Idaho ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by Interconnection Customer on March 15, 2010; also known as Project # 324; and

WHEREAS, Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System; and

WHEREAS, Interconnection Customer has requested the Transmission Provider to perform a feasibility study to assess the feasibility of interconnecting the proposed Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed an interconnection feasibility study consistent the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of the feasibility study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The feasibility study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, as may be modified as the result of the scoping meeting. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the feasibility study and as designated in accordance with the standard Small Generator Interconnection Procedures. If the Interconnection Customer modifies its Interconnection Request, the time to complete the feasibility study may be extended by agreement of the Parties.

5.0 In performing the study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Customer shall not be charged for such existing studies; however, the Interconnection Customer shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the feasibility study.

6.0 The feasibility study report shall provide the following analyses for the purpose of identifying any potential adverse system impacts that would result from the interconnection of the Small Generating Facility as proposed:

6.1 Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

6.2 Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;

6.3 Initial review of grounding requirements and electric system protection; and

6.4 Description and non-bonding estimated cost of facilities required to interconnect the proposed Small Generating Facility and to address the identified short circuit and power flow issues.

7.0 The feasibility study shall model the impact of the Small Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Small Generating Facility is being installed.

8.0 The study shall include the feasibility of any interconnection at a proposed project site where there could be multiple potential Points of Interconnection, as requested by the Interconnection Customer and at the Interconnection Customer's cost.

9.0 In lieu of Feasibility Study deposit, Interconnection Customer agrees that study funds will be drawn from the application fee for the performance of the Interconnection Feasibility Study.

Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Feasibility Study. Any difference between the deposit and the actual cost of the study shall be paid by or refunded to Interconnection Customer, as appropriate.

10.0 Once the feasibility study is completed, a feasibility study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the feasibility study must be completed and the feasibility study report transmitted within 30 business days of the Interconnection Customer's agreement to conduct a feasibility study.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

Transmission Provider: Idaho Power Company – Delivery	**Interconnection Customer:** ________________
Transmission Provider: Idaho Power Company – Delivery	**Interconnection Customer:** EXERGY DEVELOPMENT GROUP OF IDAHO
Signed: Marc Patterson	Signed
Printed: Marc Patterson	Printed JAMES T. CARKULIS
Title: Engineering Leader, T&D Planning	Title MANAGING MEMBER
Date: May 14, 2010	Date 5/19/2010

Attachment A to Feasibility Study Agreement

Assumptions Used in Conducting the Feasibility Study

The feasibility study will be based upon the information set forth in the Interconnection Request and agreed upon in the scoping meeting held on April 27, 2010:

1) Designation of Point of Interconnection and configuration to be studied.

Connecting at 138 kV to the Salmon-Wells line approximately 2 miles south of Rogerson, Idaho and approximately 6 miles west.

2) Designation of alternative Points of Interconnection and configuration.

____

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

Feasibility Study Agreement

THIS AGREEMENT is made and entered into this 19th day of MAY 2010 by and between EXERGY DEVELOPMENT GROUP OF IDAHO a LLC organized and existing under the laws of the State of IDAHO, ("Interconnection Customer,") and Idaho Power Company a Corporation existing under the laws of the State of Idaho ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by Interconnection Customer on March 15, 2010; also known as Project # 325; and

WHEREAS, Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System; and

WHEREAS, Interconnection Customer has requested the Transmission Provider to perform a feasibility study to assess the feasibility of interconnecting the proposed Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed an interconnection feasibility study consistent the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of the feasibility study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The feasibility study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, as may be modified as the result of the scoping meeting. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the feasibility study and as designated in accordance with the standard Small Generator Interconnection Procedures. If the Interconnection Customer modifies its Interconnection Request, the time to complete the feasibility study may be extended by agreement of the Parties.

5.0 In performing the study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Customer shall not be charged for such existing studies; however, the Interconnection Customer shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the feasibility study.

6.0 The feasibility study report shall provide the following analyses for the purpose of identifying any potential adverse system impacts that would result from the interconnection of the Small Generating Facility as proposed:

6.1 Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

6.2 Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;

6.3 Initial review of grounding requirements and electric system protection; and

6.4 Description and non-bonding estimated cost of facilities required to interconnect the proposed Small Generating Facility and to address the identified short circuit and power flow issues.

7.0 The feasibility study shall model the impact of the Small Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Small Generating Facility is being installed.

8.0 The study shall include the feasibility of any interconnection at a proposed project site where there could be multiple potential Points of Interconnection, as requested by the Interconnection Customer and at the Interconnection Customer's cost.

9.0 In lieu of Feasibility Study deposit, Interconnection Customer agrees that study funds will be drawn from the application fee for the performance of the Interconnection Feasibility Study.

Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Feasibility Study. Any difference between the deposit and the actual cost of the study shall be paid by or refunded to Interconnection Customer, as appropriate.

10.0 Once the feasibility study is completed, a feasibility study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the feasibility study must be completed and the feasibility study report transmitted within 30 business days of the Interconnection Customer's agreement to conduct a feasibility study.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

Transmission Provider:
Idaho Power Company – Delivery

Interconnection Customer:

____

Transmission Provider:
Idaho Power Company – Delivery

Signed: Marc Patterson

Printed: Marc Patterson

Title: Engineering Leader, T&D Planning

Date: May 14, 2010

Interconnection Customer:
EXERGY DEVELOPMENT GROUP OF IDAHO

Signed ______________________

Printed JAMES T. CARKULIS

Title MANAGING MEMBER

Date 5/19/2010

Attachment A to Feasibility Study Agreement

Assumptions Used in Conducting the Feasibility Study

The feasibility study will be based upon the information set forth in the Interconnection Request and agreed upon in the scoping meeting held on April 27, 2010:

1) Designation of Point of Interconnection and configuration to be studied.

Connecting at 345 kV to the Humboldt-Midpoint line approximately 2 miles south of Rogerson, Idaho.

2) Designation of alternative Points of Interconnection and configuration.

---

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 7

INTERCONNECTION FEASIBILITY STUDY AGREEMENT

THIS AGREEMENT is made and entered into this 19th day of MAY, 2010, by and between EXERGY DEVELOPMENT GROUP, of IDAHO a LLC organized and existing under the laws of the State of IDAHO, ("Interconnection Customer,") and Idaho Power Company a Corporation existing under the laws of the State of Idaho, ("Transmission Provider "). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop the Jack Ranch generation project, located in Twin Falls County, IDAHO, hereafter referred to as "Large Generating Facility", consistent with the Interconnection Request submitted by Interconnection Customer, also known as Project #327; and

WHEREAS, Interconnection Customer desires to interconnect the Large Generating Facility with Transmission Provider's Transmission System (the "Transmission System");

WHEREAS, Interconnection Customer has requested Transmission Provider to perform an Interconnection Feasibility Study to assess the feasibility of interconnecting the proposed Large Generating Facility to the Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved Standard Large Generator Interconnection Procedures ("LGIP") Attachment M, Idaho Power Company, FERC Electric Tariff, Original Volume No. 6.

2.0 Interconnection Customer elects and Transmission Provider shall cause to be performed an Interconnection Feasibility Study consistent with Section 6.0 of the LGIP in accordance with the Tariff.

3.0 The scope of the Interconnection Feasibility Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interconnection Feasibility Study shall be based on the technical information provided by Interconnection Customer in the Interconnection

Request, as may be modified as the result of the Scoping Meeting. Transmission Provider reserves the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Feasibility Study and as designated in accordance with Section 3.3.4 of the LGIP. If, after the designation of the Point of Interconnection pursuant to Section 3.3.4 of the LGIP, Interconnection Customer modifies its Interconnection Request pursuant to Section 4.4, the time to complete the Interconnection Feasibility Study may be extended.

5.0 The Interconnection Feasibility Study report shall provide the following information:

- preliminary identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

- preliminary identification of any thermal overload or voltage limit violations resulting from the interconnection; and

- preliminary description and non-bonding estimated cost of facilities required to interconnect the Large Generating Facility to the Transmission System and to address the identified short circuit and power flow issues.

6.0 In lieu of Feasibility Study deposit, Interconnection Customer agrees that study funds will be drawn from the application fee for the performance of the Interconnection Feasibility Study.

Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Feasibility Study.

Any difference between the deposit and the actual cost of the study shall be paid by or refunded to Interconnection Customer, as appropriate.

7.0 Effective Date, Duration and Termination. This Agreement becomes effective upon execution by all Parties and shall continue until the work required by the Agreement is completed; provided, however, the Interconnection Customer may terminate this Agreement at any time after providing written notice. In addition, if Interconnecting Customer withdraws its application for interconnection, this Agreement shall terminate effective with the date the application for interconnection is withdrawn.

8.0 No Obligation to Complete Generating Facility. Nothing in this Agreement obligates Interconnection Customer to continue or complete development of the Large Generating Facility or enter into a Large Generator Interconnection Agreement ("LGIA"). A binding agreement and commitment with respect to interconnecting the Large Generating Facility to the Transmission System will only occur upon the execution of an LGIA by Transmission Provider and Interconnection Customer.

9.0 Relationship of the Parties. This Agreement is intended to create an independent contractor relationship between the Parties. It is not to be construed as constituting the Parties as partners, as creating a joint venture, or as creating any other form of legal association or arrangement which would impose liability upon a Party for the act or omission of the other Party.

Transmission Provider shall be responsible for performance and cost of work specified in Attachment A; provided however, that such work shall be performed in accordance with and subject to, Interconnection Customer's right to final review and acceptance, which shall not unreasonably be withheld.

10.0 Standard of Care and Remedies. If any of Transmission Provider's work under this Agreement does not comply with Good Utility Practice including standard design requirements specified in the NERC Facility Connection Requirements, dated January 19, 2006, Transmission Provider will, upon written notice from Interconnection Customer, promptly re-perform the work at Transmission Provider's sole cost.

In no event will Transmission Provider or Interconnecting Customer or any of their respective agents, employees, officers, directors, affiliates or representatives be liable for incidental, special, punitive or consequential damages including but not limited to lost profits, even if the Parties have been advised of the possibility of such damages. Interconnecting Customer agrees that Transmission Provider's liability arising out of this Agreement and the services provided under this Agreement, whether under theories of contract, negligence, tort, strict liability, warranty or equity will not exceed the amounts payable by Interconnecting Customer to Transmission Provider for the services that are the basis of such claim.

11.0 Governing Law. The validity, interpretation and performance of this Agreement shall be governed by the laws of the State of Idaho, without regard to its conflict of law principles; and in addition, shall be subject to all applicable federal laws, regulations and judicial or administrative orders

of the Federal Energy Regulatory Commission. Venue for any action to enforce the terms and conditions of this Agreement shall be in Boise, Idaho.

12.0 Amendment. This Agreement may not be modified except by mutual agreement by a signed document duly executed by both Parties.

13.0 Waiver. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

14.0 Severability and Savings Clause. If any provision of this Agreement is held to be void, voidable, contrary to public policy, or unenforceable, that provision will be deemed severable from the Agreement as to the smallest part so held, and the remainder of the Agreement will continue in full effect as if the severed provision had not been included, in which case the Agreement will be construed and interpreted to implement the objectives of the Parties as stated in this Agreement. The Parties agree that neither Party will be deemed the drafter of any term that may subsequently be found to be ambiguous or vague.

15.0 Survival. This Agreement shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, to permit the determination and enforcement of liability obligations arising from acts or events that occurred while this Agreement was in effect.

16.0 Assignment and Subcontracts. This Agreement may not be transferred or assigned by either Party hereto without the prior written consent of the other Party, which such consent will not be unreasonably be withheld. Transmission Provider may subcontract any portion of the work required by this Agreement without the permission of the Interconnecting Customer.

17.0 Successors and Assigns. This Agreement shall be binding upon and inure to the benefit of the Parties hereto and their respective successors and permitted assigns. Nothing in this Agreement shall be deemed to confer upon any other person any rights, remedies, obligations or liabilities under or by reason of this Agreement.

18.0 Notices. Any notice required by this Agreement is properly given if submitted in writing and delivered to the individual set forth below in person, delivered to a nationally recognized overnight courier service properly addressed and with delivery charges prepaid, delivered to the United States Postal Service properly addressed and with proper postage prepaid, transmitted by facsimile with confirmation of successful transmission, or transmitted by email. Either Party may change at any time the individual authorized to receive notice, an address, telephone number or email address by providing notice to the other Party.

If to Interconnecting Customer, to: Company name	2nd contact info (if applicable)
____________	____________
____________	____________
Attn: COLLIN RUDEEN	____________
title LEAD PROJECT ENGINER	____________
Ph (208) 336-9793	Ph ____________
Fax (208) 336-9431	Fax ____________
Email: crudeen@energydevelopment.com	Email: ____________

If to the Transmission Provider, to:

Idaho Power Company
1221 West Idaho Street
Boise, ID 83702
Attn: Candace Gentry
Phone: 208.388.2276
Email: cgentry@idahopower.com

19.0 Entire Agreement. This Agreement and its Attachments constitutes the complete agreement between the Parties concerning its subject matter and supersedes all previous communications, negotiation, and agreements, whether oral or written, with respect to this Agreement. None of the terms or obligations under this Agreement may be changed or waived in any manner whatsoever by an action or inaction of either Party unless in a writing duly executed by the Parties. Any provision of this Agreement which is prohibited or unenforceable in any jurisdiction shall be, as to such jurisdiction, ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions in any jurisdiction, and shall not invalidate or render unenforceable such provision in any other jurisdiction.

20.0 Dispute Resolution. Any dispute between Transmission Provider and Interconnection Customer involving the provisions of this Agreement shall be referred to a senior representative of Transmission Provider and a senior representative of Interconnection Customer for resolution on an informal basis as promptly as practicable.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

Transmission Provider:

Idaho Power Company - Delivery

By: Orlando A Ciniglio

Printed: Orlando Ciniglio

Title: Leader, System Planning Engineering

Date: May 13, 2010

Interconnection Customer:

Energy Development Group of Idaho, LLC
[CUSTOMER NAME]

By:

Printed: James P. Carkulis

Title: Managing Member

Date: 5/19/2010

Attachment A

ASSUMPTIONS USED IN CONDUCTING THE INTERCONNECTION FEASIBILITY STUDY

The Interconnection Feasibility Study will be based upon the information set forth in the Interconnection Request.

Designation of Point of Interconnection and configuration to be studied.

A single connection to the Midpoint – Humboldt 345 kV line at the Jack Ranch project site.

Designation of alternative Point(s) of Interconnection and configuration.

[Above assumptions to be completed by Interconnection Customer and other assumptions to be provided by Interconnection Customer and Transmission Provider]

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 8

GENERATOR INTERCONNECTION

FEASIBILITY STUDY

for integration of the proposed

ROGERSON FLATS WIND PARK PROJECT

PROJECT #322

in

TWIN FALLS COUNTY, IDAHO

to the

IDAHO POWER COMPANY ELECTRICAL SYSTEM

for

EXERGY DEVELOPMENT GROUP OF IDAHO, LLC

the

INTERCONNECTION CUSTOMER

FINAL REPORT

July 1, 2010

CP

1.0 Introduction

Exergy Development Group of Idaho, LLC has contracted with Idaho Power Company (IPCo) to perform a Generator Interconnection Feasibility Study for the integration of the proposed 20 MW Rogerson Flats Wind Park Project (project #322). The location of the project is in Idaho Power's Southern Idaho service territory at the coordinates N42.2272°, W114.6538°. This location is approximately 2 miles west of the town of Rogerson, ID. See Appendix B for general location map of project area.

This report documents the basis for and the results of this Feasibility Study for the Rogerson Flats Wind Park. It describes the proposed project, the study cases used, the impact of associated projects, and results of all work in the areas of concern.

2.0 Summary

The proposed project is a 20 MW wind farm consisting of ten 2.05 MW REpower wind turbines. A new substation will need to be built on the site of the wind park. This substation will be built by the generation interconnection customer and have a high side breaker. It will be connected to the Upper Salmon B to Wells (US34-WELS) 138 kV transmission line. This line will need to be rebuilt for a stretch of ten miles. The generation facility will also be required to consume up to 10 MVAR when generating at full output.

There are limitations in the Midpoint West transmission system to the north and west of this area. Because of these limitations, a Transmission System Impact Study will need to be conducted to determine if additional system upgrades are required.

The estimated cost for all required upgrades of IPCo owned facilities to serve the full project is **$3,200,000.**

3.0 Scope of Interconnection Feasibility Study

The Interconnection Feasibility Study was done and prepared in accordance with Idaho Power Company Standard Generator Interconnection Procedures, to provide a preliminary evaluation of the feasibility of the interconnection of the proposed generating project to the Idaho Power system. As listed in the Interconnection Feasibility Study agreement, the Interconnection Feasibility Study report provides the following information:

- preliminary identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

- preliminary identification of any thermal overload or voltage limit violations resulting from the interconnection; and

- preliminary description and non-binding estimated cost of facilities required to interconnect the Small Generating Facility to the Distribution System and to address the identified short circuit and power flow issues.

All other proposed Generation projects prior to this project in the Generator Interconnect queue were considered in this study. A current list of these projects can be found on the Idaho Power web site as follows:

http://www.oatioasis.com/ipco/index.html.

4.0 Description of Proposed Generating Project

Rogerson Flats Wind Park proposes to connect to the Idaho Power transmission system for an injection of 20 MW (maximum project output) using ten REpower 2.05 MW wind turbines.

5.0 Description of Transmission Facilities

The closest 138 kV transmission line to the wind park is the US34 - WELS 138 kV transmission line. This line serves the substations of Blue Gulch (BUGU) and Border (BRDR). It is comprised of 4/0 ACSR which has a thermal conductor rating of 89.2 MVA. However, due to age and lack of growth in the area this line has deteriorated and upgrades have not been carried out. Due to this, the rating on the line has been recommended at 50 MVA. Under light loading conditions, when generation is high in the Magic Valley, the opening of the WELS breaker causes an overload on the US34-BUGU portion of the line. This, in part, is due to the generation from projects #135 and #159. To alleviate this overload, this section of line (10 miles) will need to be rebuilt with 397 ACSR.

High voltage is also a concern, even with the addition of the 230:138 kV transformer at KING substation that is required by previous projects in the generation queue. Assuming the KING transformer is in and the aforementioned rebuild is complete, the generation facility will be required to consume up to 10 MVAR to bring the voltage back to its original value. The facility will have to run underexcited and/or potentially add a 138 kV reactor to accomplish this. This will be the responsibility of the generation interconnection customer, those costs are not included in this report. In order to supply this reactive load a capacitor will be needed. It is possible that this support could come from the 36 MVAR KING capacitor. This capacitor would have little use when the KING transformer is placed in service, so its availability would be open.

There are limitations in the Midpoint West transmission system to the north and west of this area. Because of these limitations, a Transmission System Impact Study will need to be conducted to determine if additional system upgrades are required.

6.0 Description of Substation Facilities

Rogerson Flats will be required to build its own substation for interconnection. This substation will be owned and operated by the customer. A delta low side, grounded-wye high side transformer will be required for protection purposes. Also, IPCo will install and operate a 138 kV breaker at the new substation. This is where the Point of Interconnection (POI) will occur.

7.0 Description of Existing Distribution Facilities

The wind park's collector system will be built, owned and operated by the generation interconnection customer. There are no distribution related issues to consider in reference to IPCo.

8.0 Circuit Breaker Short Circuit Limits

Existing power circuit breakers on the US34-WELS line were evaluated for short circuit interrupting capability with the addition of the 20 MW Rogerson Flats Wind project. This feasibility study indicates there is adequate short circuit interrupting capability on these breakers for the addition of this generation project.

9.0 Description and Cost Estimate of Required Facility Upgrades

At the transmission level ten miles of 4/0 ACSR conductor needs to be rebuilt from US34 to BUGU at 397 ACSR. A breaker will be required at the POI in the new substation to be built by the interconnection customer. Also, three air break switches will be required at the transmission tap point.

Description	Cost
10 miles of transmission with 3 new air break installations	$2,700,000
138 kV breaker	$500,000
Total Estimated Cost	**$3,200,000**

Table 1: Estimated Costs for Required Upgrades

These cost estimates include direct equipment and installation labor costs, indirect labor costs and overheads. (Tax Gross Up has not been included presuming construction of interconnection facilities will not qualify under IRS rules as a taxable event. Allowance for funds used during construction (AFUDC) has not been included in the cost estimates since it is assumed that IPCO will be provided up-front funding by the Project). These are cost estimates only and final charges to the customer will be based on the actual construction costs incurred.

10.0 Description of Operating Requirements

In addition to these upgrades, there are also several operating requirements that must be met. The project will be controlled to operate at an 89% power factor (underexcited). However, temporary excursions lower than this are allowed while excursions greater than this are not. The project will have to meet the voltage schedule provided by Idaho Power. If these requirements can not be met, further voltage studies will be necessary. Voltage flicker at startup and during operation will be limited to less than 5% as measured at the POI. The project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-1992 *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems.*

11.0 Conclusions

The requested interconnection of the Rogerson Flats Wind Park to Idaho Power's system was studied. The results of this study work confirm that the existing Idaho Power system can be upgraded to handle this project. The known required upgrades for the system are listed. An IPCo Transmission System Impact Study is required to determine further transmission upgrades needed to serve this project.

APPENDIX A

A-1.0 Method of Study

The Feasibility Study plan inserts the Project up to the maximum requested injection into the selected Western Electric Coordinating Council (WECC) power flow case and then, using Power World Simulator Version 12, examines the impacts of the new resource on Idaho Power's transmission system (lines, transformers, etc.) within the study area under various operating/outage scenarios. The WECC and Idaho Power reliability criteria and Idaho Power operating procedures were used to determine the acceptability of the configurations considered. The WECC case is a recent case modified to simulate stressed but reasonable pre-contingency energy transfers utilizing the IPC system. For distribution feeder analysis, Idaho Power utilizes Advantica's SynerGEE Software.

A-2.0 Acceptability Criteria

The following acceptability criteria were used in the power flow analysis to determine under which system configuration modifications may be required:

The continuous rating of equipment is assumed to be the normal thermal rating of the equipment. This rating will be as determined by the manufacturer of the equipment or as determined by Idaho Power. Less than or equal to 100% of continuous rating is acceptable.

Idaho Power's Voltage Operating Guidelines were used to determine voltage requirements on the system. This states, in part, that distribution voltages, under normal operating conditions, are to be maintained within plus or minus 5% (0.05 per unit) of nominal everywhere on the feeder. Therefore, voltages greater than or equal to 0.95 pu voltage and less than or equal to 1.05 pu voltage are acceptable.

Voltage flicker during starting or stopping the generator is limited to 5% as measured at the point of interconnection, per Idaho Power's T&D Advisory Information Manual.

Idaho Power's Reliability Criteria for System Planning was used to determine proper transmission system operation.

All customer generation must meet IEEE 519 and ANSI C84.1 Standards.

All other applicable national and Idaho Power standards and prudent utility practices were used to determine the acceptability of the configurations considered.

The stable operation of the system requires an adequate supply of volt-amperes reactive (VARs) to maintain a stable voltage profile under both steady-state and dynamic system conditions. An inadequate supply of VARs will result in voltage decay or even collapse under the worst conditions.

Equipment/line/path ratings used will be those that are in use at the time of the study or that are represented by IPC upgrade projects that are either currently under construction or whose budgets have been approved for construction in the near future. All other potential future ratings are outside the scope of this study. Future transmission changes may, however, affect current facility ratings used in the study.

A-3.0 Grounding Guidance

Idaho Power Company (IPC) requires interconnected transformers to limit their ground fault current to 20 amps at the point of interconnection.

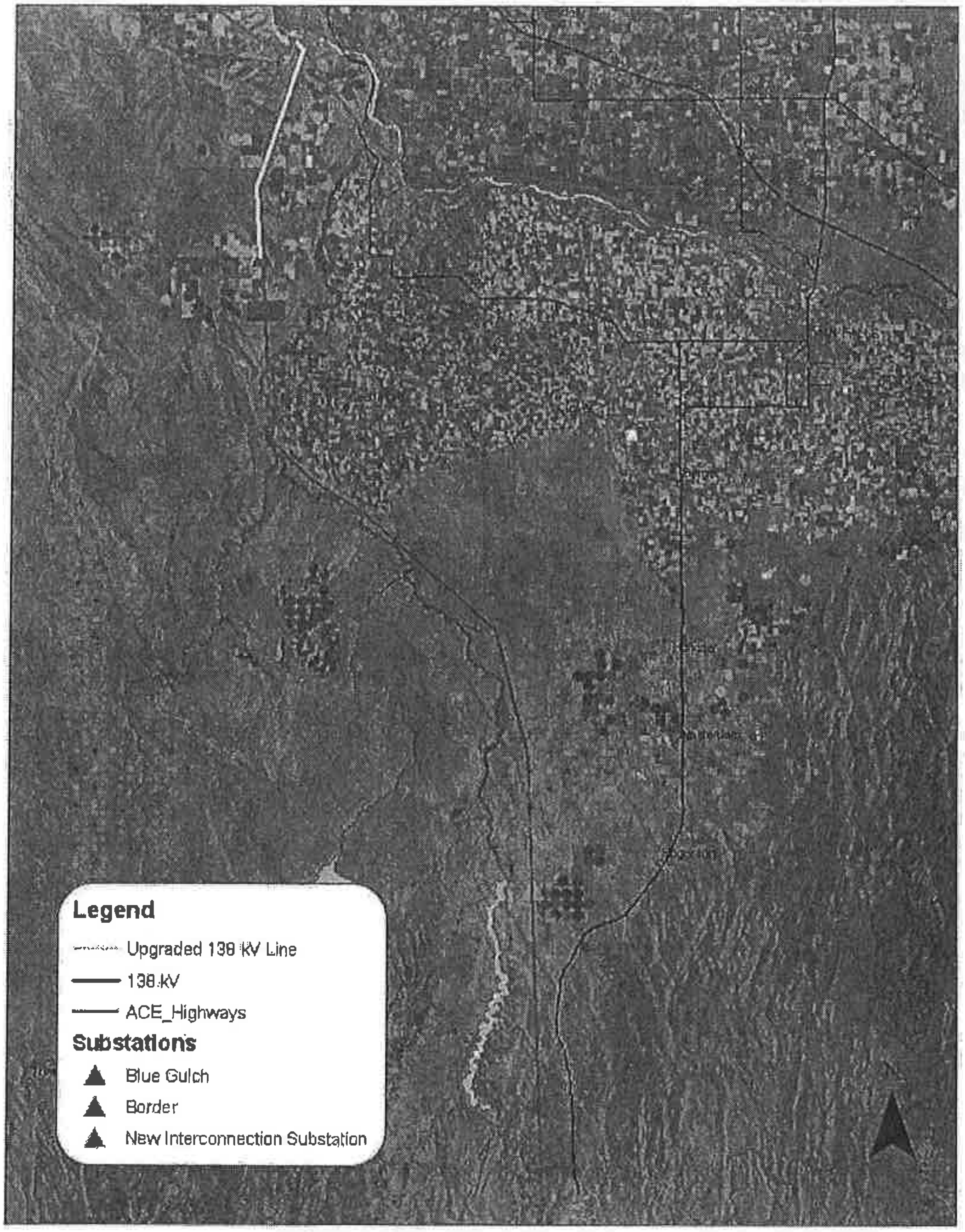
A-4.0 Electrical System Protection Guidance

IPC requires electrical system protection per Requirements for Generation Interconnections found on the Idaho Power Web site, http://www.idahopower.com/aboutus/business/generationInterconnect/.

A-5.0 WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Requirements

IPC requires frequency operational limits to adhere to WECC Under-frequency and Over-frequency Limits per the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Requirements available upon request.

APPENDIX B



Rogerson Flats Location Map with Upgrades

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This report contains Idaho Power Company Critical Energy Infrastructure Information (CEII). Distribution of this report must be limited to parties that have entered into a non-disclosure agreement with Idaho Power Company and have a need to know.

CP

GENERATOR INTERCONNECTION
FEASIBILITY STUDY

for integration of the proposed

COTTONWOOD WIND PARK PROJECT

PROJECT #323

in

TWIN FALLS COUNTY, IDAHO

to the

IDAHO POWER COMPANY ELECTRICAL SYSTEM

for

EXERGY DEVELOPMENT GROUP OF IDAHO, LLC

the

INTERCONNECTION CUSTOMER

FINAL REPORT

July 1, 2010

CP

1.0 Introduction

Exergy Development Group of Idaho, LLC has contracted with Idaho Power Company (IPCo) to perform a Generator Interconnection Feasibility Study for the integration of the proposed 20 MW Cottonwood Wind Park Project (project #322). The location of the project is in Idaho Power's Southern Idaho service territory at the coordinates N42.2090°, W114.7053°. This location is approximately 5 miles west of the town of Rogerson, ID. See Appendix B for general location map of project area.

This report documents the basis for and the results of this Feasibility Study for the Cottonwood Wind Park. It describes the proposed project, the study cases used, the impact of associated projects, and results of all work in the areas of concern.

2.0 Summary

The proposed project is a 20 MW wind farm consisting of ten 2.05 MW REpower wind turbines. A new substation will need to be built on the site of the wind park. This substation will be built by the generation interconnection customer and have a high side breaker. This breaker installation, along with 10 miles of reconductoring on the Upper Salmon B to Wells (US34-WELS) 138 kV transmission line, will be borne by project #322. Project #323 will be required to consume up to 9 MVAR when generating at full output.

There are limitations in the Midpoint West transmission system to the north and west of this area. Because of these limitations, a Transmission System Impact Study will need to be conducted to determine if additional system upgrades are required.

The estimated cost for all required upgrades of IPCo owned facilities to serve the full project is **$0**.

3.0 Scope of Interconnection Feasibility Study

The Interconnection Feasibility Study was done and prepared in accordance with Idaho Power Company Standard Generator Interconnection Procedures, to provide a preliminary evaluation of the feasibility of the interconnection of the proposed generating project to the Idaho Power system. As listed in the Interconnection Feasibility Study agreement, the Interconnection Feasibility Study report provides the following information:

- preliminary identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

- preliminary identification of any thermal overload or voltage limit violations resulting from the interconnection; and

- preliminary description and non-binding estimated cost of facilities required to interconnect the Small Generating Facility to the Distribution System and to address the identified short circuit and power flow issues.

All other proposed Generation projects prior to this project in the Generator Interconnect queue were considered in this study. A current list of these projects can be found on the Idaho Power web site as follows:

http://www.oatioasis.com/ipco/index.html.

4.0 Description of Proposed Generating Project

Cottonwood Wind Park proposes to connect to the Idaho Power transmission system for an injection of 20 MW (maximum project output) using ten REpower 2.05 MW wind turbines.

5.0 Description of Transmission Facilities

The closest 138 kV transmission line to the wind park is the US34 - WELS 138 kV transmission line. This line serves the substations of Blue Gulch (BUGU) and Border (BRDR). It is comprised of 4/0 ACSR which has a thermal conductor rating of 89.2 MVA. However, due to age and lack of growth in the area this line has deteriorated and upgrades have not been carried out. Due to this, the rating on the line has been recommended at 50 MVA. Under light loading conditions, when generation is high in the Magic Valley, the opening of the WELS breaker causes an overload on the US34-BUGU portion of the line. This, in part, is due to the generation from projects #135 and #159. To alleviate this overload, this section of line (10 miles) will need to be rebuilt with 397 ACSR. However, project #322 will be responsible for this upgrade.

High voltage is a concern, even with the addition of the 230:138 kV transformer at KING substation that is required by previous projects in the generation queue. Assuming the KING transformer is in and the aforementioned rebuild is complete, the generation facility will be required to consume up to 9 MVAR to bring the voltage back to its original value. That is, the facility will have to run underexcited and/or potentially add a 138 kV reactor to accomplish this. This will be the responsibility of the generation interconnection customer, those costs are not included in this report. In order to supply this reactive load a capacitor will be needed. It is possible that this support could come from the 36 MVAR KING capacitor. This capacitor would have little use when the KING transformer is placed in service, so its availability would be open.

There are limitations in the Midpoint West transmission system to the north and west of this area. Because of these limitations, a Transmission System Impact Study will need to be conducted to determine if additional system upgrades are required.

6.0 Description of Substation Facilities

Cottonwood Wind Park will be required to build its own substation for interconnection. This substation will be owned and operated by the customer. A delta low side, grounded-wye high side transformer will be required for protection purposes. Also, IPCo will install and operate a 138 kV breaker at the new substation. This is where the Point of Interconnection (POI) will occur. It is assumed that this substation and breaker will be shared with project #322.

7.0 Description of Existing Distribution Facilities

The wind park's collector system will be built, owned and operated by the generation interconnection customer. There are no distribution related issues to consider in reference to IPCo.

8.0 Circuit Breaker Short Circuit Limits

Existing power circuit breakers on the US34-WELS line were evaluated for short circuit interrupting capability with the addition of the 20 MW Cottonwood Wind project. This feasibility study indicates there is adequate short circuit interrupting capability on these breakers for the addition of this generation project.

9.0 Description and Cost Estimate of Required Facility Upgrades

No costs will need to be incurred for improvements to the Idaho Power system. However, the interconnection customer will have to supply its own substation and consume 9 MVAR of reactive power.

10.0 Description of Operating Requirements

In addition to these upgrades, there are also several operating requirements that must be met. The project will be controlled to operate at a 91% power factor (underexcited). However, temporary excursions lower than this are allowed while excursions greater than this are not. The project will have to meet the voltage schedule provided by Idaho Power. If these requirements can not be met, further voltage studies will be necessary. Voltage flicker at startup and during operation will be limited to less than 5% as measured at the POI. The project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-1992 *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems.*

11.0 Conclusions

The requested interconnection of the Cottonwood Wind Park to Idaho Power's system was studied. The results of this study work confirm that the existing Idaho Power system can handle this project with some adjustments. The known adjustments are described above. An IPCo Transmission System Impact Study is required to determine transmission upgrades needed to serve this project.

APPENDIX A

A-1.0 Method of Study

The Feasibility Study plan inserts the Project up to the maximum requested injection into the selected Western Electric Coordinating Council (WECC) power flow case and then, using Power World Simulator Version 12, examines the impacts of the new resource on Idaho Power's transmission system (lines, transformers, etc.) within the study area under various operating/outage scenarios. The WECC and Idaho Power reliability criteria and Idaho Power operating procedures were used to determine the acceptability of the configurations considered. The WECC case is a recent case modified to simulate stressed but reasonable pre-contingency energy transfers utilizing the IPC system. For distribution feeder analysis, Idaho Power utilizes Advantica's SynerGEE Software.

A-2.0 Acceptability Criteria

The following acceptability criteria were used in the power flow analysis to determine under which system configuration modifications may be required:

The continuous rating of equipment is assumed to be the normal thermal rating of the equipment. This rating will be as determined by the manufacturer of the equipment or as determined by Idaho Power. Less than or equal to 100% of continuous rating is acceptable.

Idaho Power's Voltage Operating Guidelines were used to determine voltage requirements on the system. This states, in part, that distribution voltages, under normal operating conditions, are to be maintained within plus or minus 5% (0.05 per unit) of nominal everywhere on the feeder. Therefore, voltages greater than or equal to 0.95 pu voltage and less than or equal to 1.05 pu voltage are acceptable.

Voltage flicker during starting or stopping the generator is limited to 5% as measured at the point of interconnection, per Idaho Power's T&D Advisory Information Manual.

Idaho Power's Reliability Criteria for System Planning was used to determine proper transmission system operation.

All customer generation must meet IEEE 519 and ANSI C84.1 Standards.

All other applicable national and Idaho Power standards and prudent utility practices were used to determine the acceptability of the configurations considered.

The stable operation of the system requires an adequate supply of volt-amperes reactive (VARs) to maintain a stable voltage profile under both steady-state and dynamic system conditions. An inadequate supply of VARs will result in voltage decay or even collapse under the worst conditions.

Equipment/line/path ratings used will be those that are in use at the time of the study or that are represented by IPC upgrade projects that are either currently under construction or whose budgets have been approved for construction in the near future. All other potential future ratings are outside the scope of this study. Future transmission changes may, however, affect current facility ratings used in the study.

A-3.0 Grounding Guidance

Idaho Power Company (IPC) requires interconnected transformers to limit their ground fault current to 20 amps at the point of interconnection.

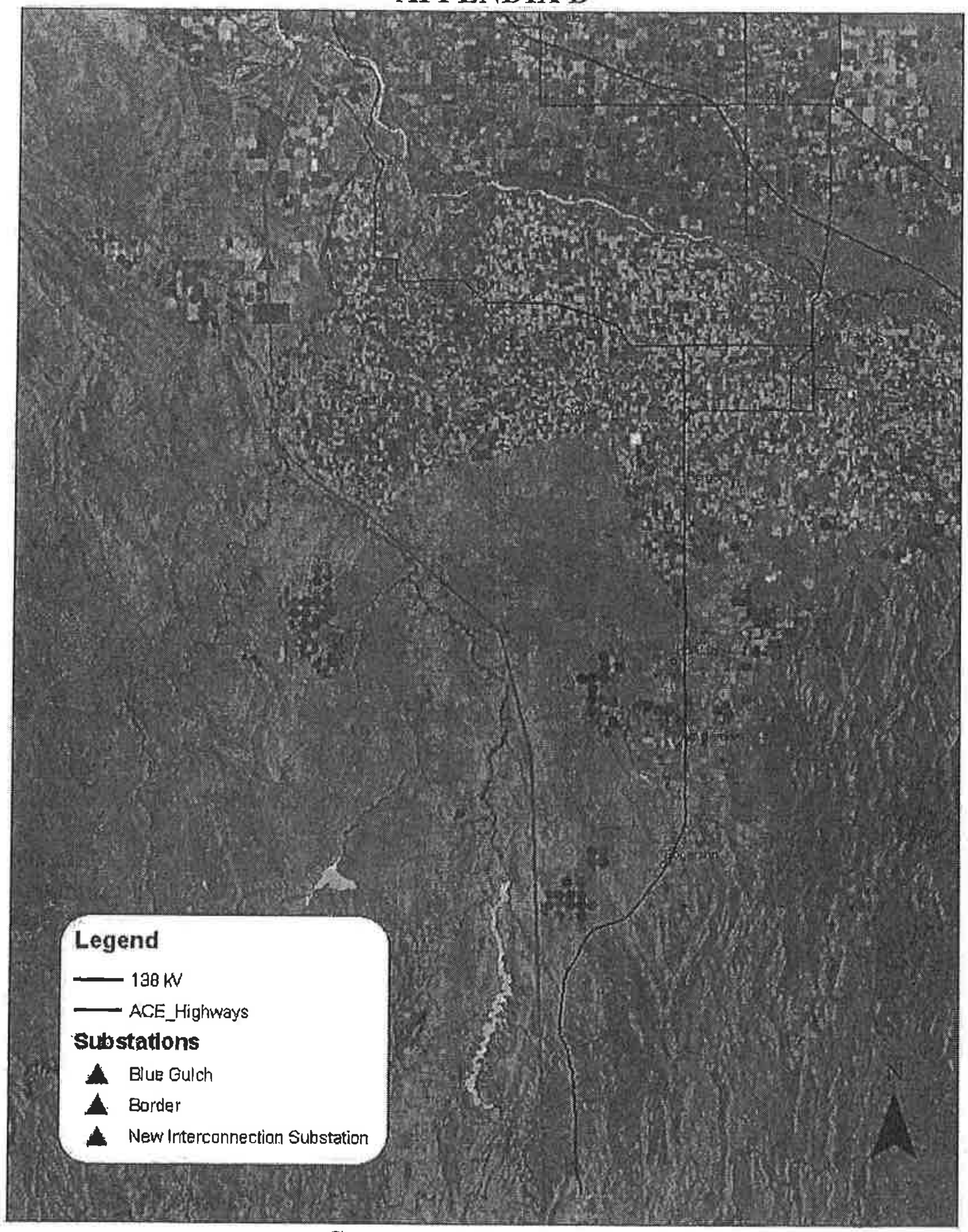
A-4.0 Electrical System Protection Guidance

IPC requires electrical system protection per Requirements for Generation Interconnections found on the Idaho Power Web site, http://www.idahopower.com/aboutus/business/generationInterconnect/.

A-5.0 WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Requirements

IPC requires frequency operational limits to adhere to WECC Under-frequency and Over-frequency Limits per the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Requirements available upon request.

APPENDIX B



Cottonwood Location Map

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GENERATOR INTERCONNECTION

FEASIBILITY STUDY

for integration of the proposed

DEEP CREEK WIND PARK PROJECT

PROJECT #324

in

TWIN FALLS COUNTY, IDAHO

to the

IDAHO POWER COMPANY ELECTRICAL SYSTEM

for

EXERGY DEVELOPMENT GROUP OF IDAHO, LLC

the

INTERCONNECTION CUSTOMER

FINAL REPORT

July 1, 2010

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This report contains Idaho Power Company Critical Energy Infrastructure Information (CEII). Distribution of this report must be limited to parties that have entered into a non-disclosure agreement with Idaho Power Company and have a need to know.

CP

1.0 Introduction

Exergy Development Group of Idaho, LLC has contracted with Idaho Power Company (IPCo) to perform a Generator Interconnection Feasibility Study for the integration of the proposed 20 MW Deep Creek Wind Park Project (project #324). The location of the project is in Idaho Power's Southern Idaho service territory at the coordinates N42.1980°, W114.6735°. This location is approximately 4 miles west of the town of Rogerson, ID. See Appendix B for general location map of project area.

This report documents the basis for and the results of this Feasibility Study for the Deep Creek Wind Park. It describes the proposed project, the study cases used, the impact of associated projects, and results of all work in the areas of concern.

2.0 Summary

The proposed project is a 20 MW wind farm consisting of ten 2.05 MW REpower wind turbines. A new substation will need to be built on the site of the wind park. This substation will be built by the generation interconnection customer and have a high side breaker. This breaker installation, along with 10 miles of reconductoring on the Upper Salmon B to Wells (US34-WELS) 138 kV transmission line, will be borne by project #322. Project #324 will be required to construct 34 additional miles of 138 kV transmission with 397 ACSR.

There are limitations in the Midpoint West transmission system to the north and west of this area. Because of these limitations, a Transmission System Impact Study will need to be conducted to determine if additional system upgrades are required.

The estimated cost for all required upgrades of IPCo owned facilities to serve the full project is **$8,500,000.**

3.0 Scope of Interconnection Feasibility Study

The Interconnection Feasibility Study was done and prepared in accordance with Idaho Power Company Standard Generator Interconnection Procedures, to provide a preliminary evaluation of the feasibility of the interconnection of the proposed generating project to the Idaho Power system. As listed in the Interconnection Feasibility Study agreement, the Interconnection Feasibility Study report provides the following information:

- preliminary identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

- preliminary identification of any thermal overload or voltage limit violations resulting from the interconnection; and

- preliminary description and non-binding estimated cost of facilities required to interconnect the Small Generating Facility to the Distribution System and to address the identified short circuit and power flow issues.

All other proposed Generation projects prior to this project in the Generator Interconnect queue were considered in this study. A current list of these projects can be found on the Idaho Power web site as follows:

http://www.oatioasis.com/ipco/index.html.

4.0 Description of Proposed Generating Project

Deep Creek Wind Park proposes to connect to the Idaho Power transmission system for an injection of 20 MW (maximum project output) using ten REpower 2.05 MW wind turbines.

5.0 Description of Transmission Facilities

The closest 138 kV transmission line to the wind park is the US34 - WELS 138 kV transmission line. This line serves the substations of Blue Gulch (BUGU) and Border (BRDR). It is comprised of 4/0 ACSR which has a thermal conductor rating of 89.2 MVA. However, due to age and lack of growth in the area this line has deteriorated and upgrades have not been carried out. Due to this, the rating on the line has been recommended at 50 MVA. Under light loading conditions, when generation is high in the Magic Valley, the opening of the WELS breaker causes an overload from the new substation for this project to US34. Part of this line (US34-BUGU) will be rebuilt by project #322. The rest of this line will also need to be rebuilt with 397 ACSR. This portion is 34 miles and extends from the new substation to BUGU.

With the line rebuilt this generation addition will be required to maintain unity power factor. Also, projects #322 and #323 will need to maintain their underexcited states all year long.

There are limitations in the Midpoint West transmission system to the north and west of this area. Because of these limitations, a Transmission System Impact Study will need to be conducted to determine if additional system upgrades are required.

6.0 Description of Substation Facilities

Deep Creek Wind Park will be required to build its own substation for interconnection. This substation will be owned and operated by the customer. A delta low side, grounded-wye high side transformer will be required for protection purposes. Also, IPCo will install and operate a 138 kV breaker at the new substation. This is where the Point of Interconnection (POI) will occur. It is assumed that this substation and breaker will be shared with projects #322 and #323.

7.0 Description of Existing Distribution Facilities

The wind park's collector system will be built, owned and operated by the generation interconnection customer. There are no distribution related issues to consider in reference to IPCo.

8.0 Circuit Breaker Short Circuit Limits

Existing power circuit breakers on the US34-WELS line were evaluated for short circuit interrupting capability with the addition of the 20 MW Cottonwood Wind project. This feasibility study indicates there is adequate short circuit interrupting capability on these breakers for the addition of this generation project.

9.0 Description and Cost Estimate of Required Facility Upgrades

At the transmission level thirty-four miles of 4/0 ACSR conductor needs to be rebuilt from US34 to the site of the new substation to 397 ACSR.

Description	Cost
34 miles of transmission	$8,500,000
Total Estimated Cost	**$8,500,000**

Table 1: Estimated Costs for Required Upgrades

These cost estimates include direct equipment and installation labor costs, indirect labor costs and overheads. (Tax Gross Up has not been included presuming construction of interconnection facilities will not qualify under IRS rules as a taxable event. Allowance for funds used during construction (AFUDC) has not been included in the cost estimates since it is assumed that IPCO will be provided up-front funding by the Project). These are cost estimates only and final charges to the customer will be based on the actual construction costs incurred.

10.0 Description of Operating Requirements

In addition to these upgrades, there are also several operating requirements that must be met. The project will be controlled to operate at unity power factor. However, temporary excursions lower than this (underexcited) are allowed while excursions greater than this (overexcited) are not. The project will have to meet the voltage schedule provided by Idaho Power. If these requirements can not be met, further voltage studies will be necessary. Voltage flicker at startup and during operation will be limited to less than 5% as measured at the POI. The project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-1992 *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*.

11.0 Conclusions

The requested interconnection of the Deep Creek Wind Park to Idaho Power's system was studied. The results of this study work confirm that the existing Idaho Power system can be upgraded to handle this project. The known required upgrades for the system are listed. An IPCo Transmission System Impact Study is required to determine further transmission upgrades needed to serve this project.

APPENDIX A

A-1.0 Method of Study

The Feasibility Study plan inserts the Project up to the maximum requested injection into the selected Western Electric Coordinating Council (WECC) power flow case and then, using Power World Simulator Version 12, examines the impacts of the new resource on Idaho Power's transmission system (lines, transformers, etc.) within the study area under various operating/outage scenarios. The WECC and Idaho Power reliability criteria and Idaho Power operating procedures were used to determine the acceptability of the configurations considered. The WECC case is a recent case modified to simulate stressed but reasonable pre-contingency energy transfers utilizing the IPC system. For distribution feeder analysis, Idaho Power utilizes Advantica's SynerGEE Software.

A-2.0 Acceptability Criteria

The following acceptability criteria were used in the power flow analysis to determine under which system configuration modifications may be required:

> The continuous rating of equipment is assumed to be the normal thermal rating of the equipment. This rating will be as determined by the manufacturer of the equipment or as determined by Idaho Power. Less than or equal to 100% of continuous rating is acceptable.
>
> Idaho Power's Voltage Operating Guidelines were used to determine voltage requirements on the system. This states, in part, that distribution voltages, under normal operating conditions, are to be maintained within plus or minus 5% (0.05 per unit) of nominal everywhere on the feeder. Therefore, voltages greater than or equal to 0.95 pu voltage and less than or equal to 1.05 pu voltage are acceptable.
>
> Voltage flicker during starting or stopping the generator is limited to 5% as measured at the point of interconnection, per Idaho Power's T&D Advisory Information Manual.
>
> Idaho Power's Reliability Criteria for System Planning was used to determine proper transmission system operation.
>
> All customer generation must meet IEEE 519 and ANSI C84.1 Standards.
>
> All other applicable national and Idaho Power standards and prudent utility practices were used to determine the acceptability of the configurations considered.

The stable operation of the system requires an adequate supply of volt-amperes reactive (VARs) to maintain a stable voltage profile under both steady-state and dynamic system conditions. An inadequate supply of VARs will result in voltage decay or even collapse under the worst conditions.

Equipment/line/path ratings used will be those that are in use at the time of the study or that are represented by IPC upgrade projects that are either currently under construction or whose budgets have been approved for construction in the near future. All other potential future ratings are outside the scope of this study. Future transmission changes may, however, affect current facility ratings used in the study.

A-3.0 Grounding Guidance

Idaho Power Company (IPC) requires interconnected transformers to limit their ground fault current to 20 amps at the point of interconnection.

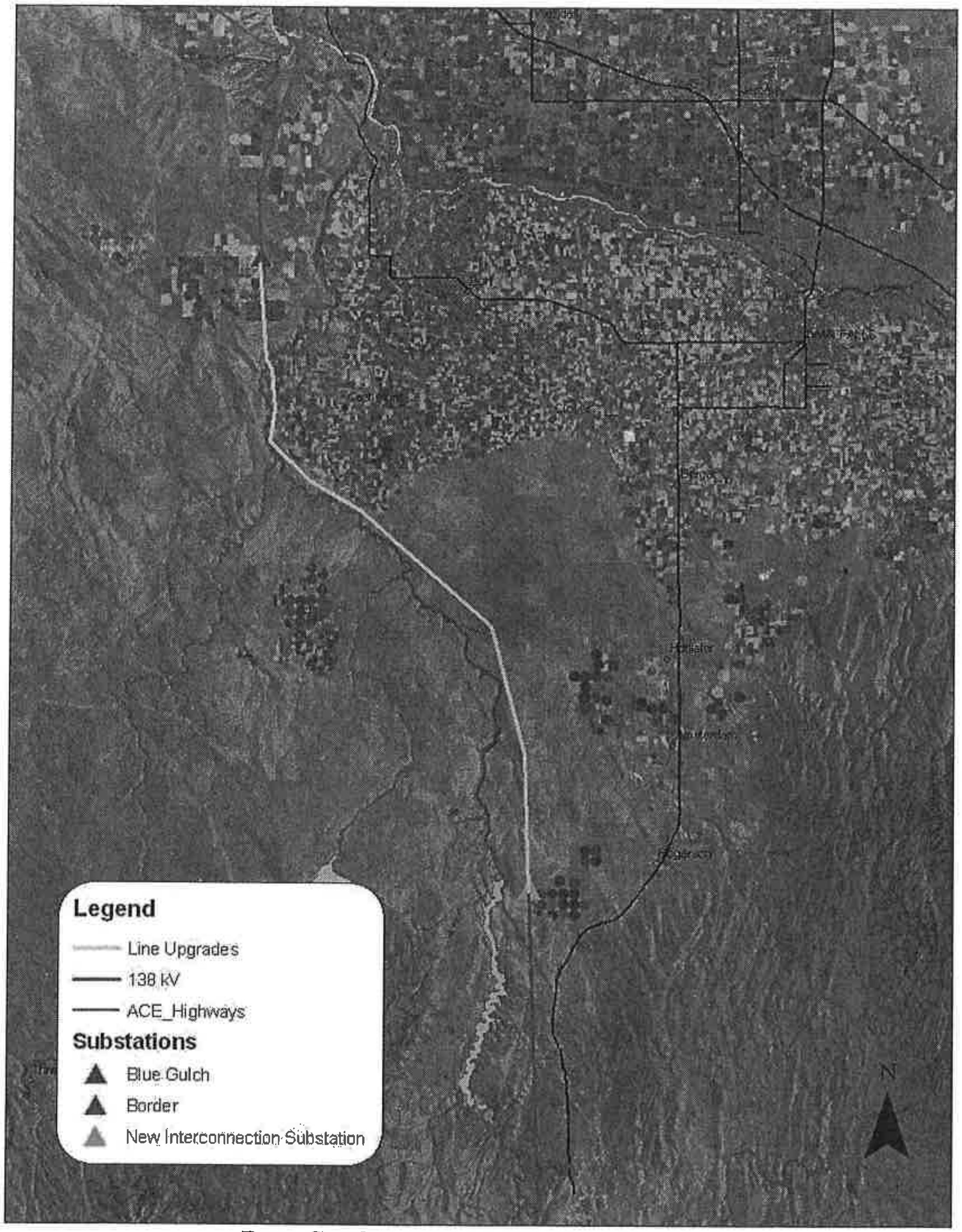
A-4.0 Electrical System Protection Guidance

IPC requires electrical system protection per Requirements for Generation Interconnections found on the Idaho Power Web site, http://www.idahopower.com/aboutus/business/generationInterconnect/.

A-5.0 WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Requirements

IPC requires frequency operational limits to adhere to WECC Under-frequency and Over-frequency Limits per the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Requirements available upon request.

APPENDIX B



Deep Creek Location Map with Upgrades

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CP

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 9

GENERATOR INTERCONNECTION FEASIBILITY STUDY

for integration of the proposed

IPC ProjectQ#325 & #327

in

TWIN FALLS COUNTY, IDAHO

to the

IDAHO POWER COMPANY ELECTRICAL SYSTEM

for

the

INTERCONNECTION CUSTOMER

DRAFT REPORT

July 8, 2010

JLE

1.0 Introduction

The Interconnection Customer has contracted with Idaho Power Company (IPC) to perform a Feasibility Study (FS) for the integration of IPC Generation Interconnection Project Queue #325 and #327, a 20 MW wind project and 200 MW wind project respectively (to be further referred to as The Project). The Project is located in IPCs southern service territory in Twin Falls County, Idaho. The new generation will be interconnected at 345 kV to a new substation. The point of interconnection to the IPC system will vary depending on the transmission upgrades selected to integrate the project.

This report documents the basis for and the results of this FS for the proposed 220 MW of wind generation. It describes the proposed project, the impact of associated projects and results of all work in the areas of concern.

2.0 Summary

This FS will look at interconnecting the project to the Midpoint – Humboldt 345 kV line.

Connecting The Project to the Midpoint – Humboldt 345 kV line will require the following:

1) A new 345/138 kV class substation at the project location.

Capacity Benefit Margin problems exist if the entire 220 MW of wind generation is sold to IPC with only a single connection to the 345 kV system. IPC has no knowledge or where this generation is planned to be sold; this problem will be addressed in an associated Transmission Service Request.

Total Estimated Cost: $10,000,000

More detail is located in Section 5.

IPC Transmission Network Upgrades may be necessary if firm transmission is required to deliver The Project's generation from the point of interconnection (point of receipt) to a point of delivery. A transmission service request (TSR) will be required to secure transmission rights on the IPC system, either through latent capacity, or Network Upgrades. Either the interconnection customer, or the merchant purchasing the generation from the interconnection customer, will have to make this TSR. Transmission rights are beyond the scope of the Generation Interconnection Process. **IPC Transmission Network Upgrade costs are not included in this GI FS, however, costs could be sizeable.**

3.0 Scope of Interconnection System Impact Study

The Interconnection Feasibility Study was done and prepared in accordance with Idaho Power Company Standard Generator Interconnection Procedures, to provide a preliminary evaluation of the feasibility of the interconnection of the proposed generating project to the Idaho Power system. As listed in Section 5.0 of the Interconnection Feasibility Study agreement, the Interconnection Feasibility Study report provides the following information:

- Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;
- Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;
- Initial review of grounding requirements and electric system protection; and
- Description and non-binding estimated cost of facilities required to interconnect the proposed Small Generating Facility and to address the identified short circuit and power flow issues.

All other proposed Generation projects prior to this project in the Generator Interconnect queue were considered in this study. A current list of these projects can be found on the Idaho Power web site, **http://www.oatioasis.com/ipco/index.html**.

4.0 Description of Proposed Generating Project

ProjectQ#325 consists of up to 20 MW of wind power and ProjectQ#327 consists of up to 200 MW of wind power. A 34.5 kV feeder system will be used to collect the generation. At a new substation, the generation will be stepped up from 34.5 kV to 345 kV.

The proposed in-service date is December, 2011.

5.0 Integration of The Project

Connecting The Project to the Midpoint – Humboldt 345 kV line will require the following:

1) A new 345/138 kV class substation at the project location.

The new 345/138 kV class substation will consist of at least one 345 kV line terminal and a customer owned 345/34.5 kV transformer. The Midpoint – Humboldt 345 kV line could be wrapped in-and-out of the new substation, however the line currently utilizes single-pole tripping. Additional studies will have to be performed to determine neutral reactor requirements at Midpoint, Humboldt, and The Project Substation with differing bus configurations at the new substation. This study assumes that single pole tripping will not be impacted if the new substation is set up as a tap on the 345 kV line. The point of interconnection will be the 345 kV breaker on the high side of the 345/34.5 kV transformer.

The IPC – Sierra transmission path's rating limits the south to north transfers across Midpoint – Humboldt to 360 MW. Existing IPC generation utilizes 262.5 MW of this transfer capability, leaving 97.5 MW of capacity available for firm transmission northbound (which may or may not be available to The Project). The 360 MW transfer limit could likely be increased by going through the WECC rating process.

IPCs Capacity Benefit Margin (CBM) is a substantial problem if the entire 220 MW output of The Project is sold to IPC. IPC holds 330 MW of firm transmission capacity in reserve for the worst case generation loss on the system. With the addition of 220 MW to the Midpoint – Humboldt 345 kV line, 262.5 MW (IPC Existing) + 272 MW (The Project) = 534.5 MW could be stranded to the Sierra system with the loss of the Midpoint – The Project 345 kV line, creating a new worst-case situation.

6.0 Operational Considerations

Idaho Power and Nevada Power will have to modify the loss calculations on the Midpoint – Humboldt – Coyote – Valmy 345 kV line with the addition of The Project.

For all options, the generation step up transformer will be connected as a solidly grounded wye on the high (transmission) side.

Dynamic reactive support at the new substation may be required for system stability. Potential system stability problems could also possibly be addressed by utilizing different types of wind turbines. System stability will be addressed in the SIS.

7.0 Network Integration of The Project

Depending on where The Project wishes to sell their generation, Network Upgrades may be required to transmit the power from the point of receipt to the point of delivery. A transmission service request will be required to secure transmission rights on the IPC system. Generation Interconnection System Impact Studies cannot allocate transmission service.

In order to utilize the generation on the IPC system, The Project's generation will be transmitted to IPCs growing Treasure Valley (Boise) area. Midpoint West, an internal IPC transmission path, is a bottleneck between The Project & Boise. In order to increase Midpoint West an additional 220 MW, a new 230 kV transmission line between Midpoint and the Treasure Valley would be required. At this point, IPC is not considering options for new 230 kV west out of Midpoint as network upgrades. IPC is in the early stages of a 500 kV transmission project known as Gateway West, which will eventually connect Midpoint to the Treasure Valley. Gateway West will increase the transmission capacity of the Midpoint West cut-plane by well over 220 MW, however this project is not scheduled for completion until sometime after 2014. Between The Project in-service date and completion of the Midpoint – Treasure Valley portion of the Gateway West project, The Project would have to operate as a conditional firm resource, available to be tripped offline if there are problems on the system. A transmission service request will be required to secure transmission rights on the IPC system, and this new transmission project.

8.0 Dynamic Stability Analysis

Dynamic Stability Analysis will be performed if the interconnecting customer chooses to move forward with the System Impact Study. To perform a stability analysis, the interconnecting customer needs to provide IPC with GE PSLF dynamic data for the specific wind turbines they plan to use. This information is required so that IPC can accurately model, and study, the stability of the system.

Additional modifications to the transmission system not identified in this Feasibility Study may be required, depending on system stability.

9.0 Description and Cost Estimate of Required Facility Upgrades

These cost estimates include direct equipment and installation labor costs, indirect labor costs and overheads (Tax Gross Up has not been included presuming construction of interconnection facilities will not qualify under IRS rules as a taxable event. Allowance for funds used during construction (AFUDC) has not been included in the cost estimates since it is assumed that IPC will be provided up-front funding by the Project). No attempt has been made in this study to assign network upgrade costs and not all of the estimated facility costs are necessarily the responsibility of The Project. These are cost estimates only and final charges to the customer will be based on the actual construction costs incurred.

Table 1. Estimated Costs for Required Idaho Power Local Area Upgrades

Description	**Cost**
New Substation (Site Work)	$1,000,000
New Substation (345 kV Portion)	$9,000,000
TOTAL	**$10,000,000**

Costs for potential Network Upgrades are not included, but could be sizable.

10.0 Conclusions

The requested interconnection of The Project to Idaho Power's system was studied. The result of this work indicates that the local area Idaho Power transmission system can be upgraded to support this project. The estimated costs of the modifications required, excluding potential network transmission upgrades, are listed in Section 9.0 of this report. These are estimated costs only and final charges to the customer will be based on the actual construction costs incurred.

Next, IPC requires further direction on what the interconnection customer would like to pursue in the System Impact Study. IPC also requires GE PSLF dynamic data about the type of wind turbines the interconnection customer plans to use to perform a detailed stability analysis of the wind project.

APPENDIX A

A-1.0 Method of Study

The System Impact Study inserts the Project up to the maximum requested injection into the selected Western Electric Coordinating Council (WECC) power flow case and then, using GE's Positive Sequence Load Flow (PSLF) analysis tools or Power World Simulator, examines the impacts of the new resource on Idaho Power's system (lines, transformers, etc.) within the study area under various operating/outage scenarios. The WECC and Idaho Power reliability criteria and Idaho Power operating procedures were used to determine the acceptability of the configurations considered. The WECC case is a recent case modified to simulate stressed but reasonable pre-contingency energy transfers utilizing the IPC system.

A-2.0 Acceptability Criteria

The following acceptability criteria were used in the power flow analysis to determine under which system configuration modifications may be required:

> The continuous rating of equipment is assumed to be the normal thermal rating of the equipment. This rating will be as determined by the manufacturer of the equipment or as determined by Idaho Power. Less than or equal to 100% of continuous rating is acceptable.
>
> Idaho Power's Voltage Operating Guidelines were used to determine voltage requirements on the system. This states, in part, that distribution voltages, under normal operating conditions, are to be maintained within plus or minus 5% (0.05 per unit) of nominal everywhere on the feeder. Therefore, voltages greater than or equal to 0.95 pu voltage and less than or equal to 1.05 pu voltage are acceptable.
>
> All customer generation must meet IEEE 519 and ANSI C84.1 Standards.
>
> All other applicable national and Idaho Power standards and prudent utility practices were used to determine the acceptability of the configurations considered.
>
> The stable operation of the system requires an adequate supply of volt-amperes reactive (VARs) to maintain a stable voltage profile under both steady-state and dynamic system conditions. An inadequate supply of VARs will result in voltage decay or even collapse under the worst conditions.

Equipment/line/path ratings used will be those that are in use at the time of the study or that are represented by IPC upgrade projects that are either currently under construction or whose budgets have been approved for construction in the near future. All other potential future ratings are outside the scope of this study. Future transmission changes may, however, affect current facility ratings used in the study.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 10

GENERATOR INTERCONNECTION FEASIBILITY STUDY

for integration of the proposed

IPC ProjectQ#325 & #327

in

TWIN FALLS COUNTY, IDAHO

to the

IDAHO POWER COMPANY ELECTRICAL SYSTEM

for

the

INTERCONNECTION CUSTOMER

FINAL REPORT

July 28, 2010

JLE

1.0 Introduction

The Interconnection Customer has contracted with Idaho Power Company (IPC) to perform a Feasibility Study (FS) for the integration of IPC Generation Interconnection Project Queue #325 and #327, a 20 MW wind project and 200 MW wind project respectively (to be further referred to as The Project). The Project is located in IPCs southern service territory in Twin Falls County, Idaho. The new generation will be interconnected at 345 kV to a new substation. The point of interconnection to the IPC system will be the customer side of the 345 kV breaker at the interconnection substation.

This report documents the basis for and the results of this FS for the proposed 220 MW of wind generation. It describes the proposed project, the impact of associated projects and results of all work in the areas of concern.

2.0 Summary

This FS will look at interconnecting the project to the Midpoint – Humboldt 345 kV line.

Connecting The Project to the Midpoint – Humboldt 345 kV line will require the following:

1) A new 345/138 kV class substation at the project location.

Capacity Benefit Margin problems exist if the entire 220 MW of wind generation is sold to IPC with only a single connection to the 345 kV system. IPC has no knowledge or where this generation is planned to be sold; this problem will be addressed in an associated Transmission Service Request.

Total Estimated Cost: $3,980,000

More detail is located in Section 5.

IPC Transmission Network Upgrades may be necessary if firm transmission is required to deliver The Project's generation from the point of interconnection (point of receipt) to a point of delivery. A transmission service request (TSR) will be required to secure transmission rights on the IPC system, either through latent capacity, or Network Upgrades. Either the interconnection customer, or the merchant purchasing the generation from the interconnection customer, will have to make this TSR. Transmission rights are beyond the scope of the Generation Interconnection Process. **IPC Transmission Network Upgrade costs are not included in this GI FS, however, costs could be sizeable.**

3.0 Scope of Interconnection System Impact Study

The Interconnection Feasibility Study was done and prepared in accordance with Idaho Power Company Standard Generator Interconnection Procedures, to provide a preliminary evaluation of the feasibility of the interconnection of the proposed generating project to the Idaho Power system. As listed in Section 5.0 of the Interconnection Feasibility Study agreement, the Interconnection Feasibility Study report provides the following information:

- Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;
- Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;
- Initial review of grounding requirements and electric system protection; and
- Description and non-binding estimated cost of facilities required to interconnect the proposed Small Generating Facility and to address the identified short circuit and power flow issues.

All other proposed Generation projects prior to this project in the Generator Interconnect queue were considered in this study. A current list of these projects can be found on the Idaho Power web site, **http://www.oatioasis.com/ipco/index.html**.

4.0 Description of Proposed Generating Project

ProjectQ#325 consists of up to 20 MW of wind power and ProjectQ#327 consists of up to 200 MW of wind power. A 34.5 kV feeder system will be used to collect the generation. At a new substation, the generation will be stepped up from 34.5 kV to 345 kV.

The proposed in-service date is December, 2011.

5.0 Integration of The Project

Connecting The Project to the Midpoint – Humboldt 345 kV line will require the following:

1) A new 345/138 kV class substation at the project location.

The new 345/138 kV class substation will consist of at least one 345 kV line terminal and a customer owned 345/34.5 kV transformer. The Midpoint – Humboldt 345 kV line could be wrapped in-and-out of the new substation, however the line currently utilizes single-pole tripping. Additional studies will have to be performed to determine neutral reactor requirements at Midpoint, Humboldt, and The Project Substation with differing bus configurations at the new substation. This study assumes that single pole tripping will not be impacted if the new substation is set up as a tap on the 345 kV line. The point of interconnection will be the 345 kV breaker on the high side of the 345/34.5 kV transformer.

The IPC – Sierra transmission path's rating limits the south to north transfers across Midpoint – Humboldt to 360 MW. Existing IPC generation utilizes 262.5 MW of this transfer capability, leaving 97.5 MW of capacity available for firm transmission northbound (which may or may not be available to The Project). The 360 MW transfer limit could likely be increased by going through the WECC rating process.

IPCs Capacity Benefit Margin (CBM) is a substantial problem if the entire 220 MW output of The Project is sold to IPC. IPC holds 330 MW of firm transmission capacity in reserve for the worst case generation loss on the system. With the addition of 220 MW to the Midpoint – Humboldt 345 kV line, 262.5 MW (IPC Existing) + 220 MW (The Project) = 482.5 MW could be stranded to the Sierra system with the loss of the Midpoint – The Project 345 kV line, creating a new worst-case situation.

6.0 Operational Considerations

Idaho Power and Nevada Power will have to modify the loss calculations on the Midpoint – Humboldt – Coyote – Valmy 345 kV line with the addition of The Project.

For all options, the generation step up transformer will be connected as a solidly grounded wye on the high (transmission) side.

Dynamic reactive support at the new substation may be required for system stability. Potential system stability problems could also possibly be addressed by utilizing different types of wind turbines. System stability will be addressed in the SIS.

7.0 Network Integration of The Project

Depending on where The Project wishes to sell their generation, Network Upgrades may be required to transmit the power from the point of receipt to the point of delivery. A transmission service request will be required to secure transmission rights on the IPC system. Generation Interconnection System Impact Studies cannot allocate transmission service.

In order to utilize the generation on the IPC system, The Project's generation will be transmitted to IPCs growing Treasure Valley (Boise) area. Midpoint West, an internal IPC transmission path, is a bottleneck between The Project & Boise. In order to increase Midpoint West an additional 220 MW, a new 230 kV transmission line between Midpoint and the Treasure Valley would be required. At this point, IPC is not considering options for new 230 kV west out of Midpoint as network upgrades. IPC is in the early stages of a 500 kV transmission project known as Gateway West, which will eventually connect Midpoint to the Treasure Valley. Gateway West will increase the transmission capacity of the Midpoint West cut-plane by well over 220 MW, however this project is not scheduled for completion until sometime after 2014. Between The Project in-service date and completion of the Midpoint – Treasure Valley portion of the Gateway West project, The Project would have to operate as a conditional firm resource, available to be tripped offline if there are problems on the system. A transmission service request will be required to secure transmission rights on the IPC system, and this new transmission project.

8.0 Dynamic Stability Analysis

Dynamic Stability Analysis will be performed if the interconnecting customer chooses to move forward with the System Impact Study. To perform a stability analysis, the interconnecting customer needs to provide IPC with GE PSLF dynamic data for the specific wind turbines they plan to use. This information is required so that IPC can accurately model, and study, the stability of the system.

Additional modifications to the transmission system not identified in this Feasibility Study may be required, depending on system stability.

9.0 Description and Cost Estimate of Required Facility Upgrades

These cost estimates include direct equipment and installation labor costs, indirect labor costs and overheads (Tax Gross Up has not been included presuming construction of interconnection facilities will not qualify under IRS rules as a taxable event. Allowance for funds used during construction (AFUDC) has not been included in the cost estimates since it is assumed that IPC will be provided up-front funding by the Project). No attempt has been made in this study to assign network upgrade costs and not all of the estimated facility costs are necessarily the responsibility of The Project. These are cost estimates only and final charges to the customer will be based on the actual construction costs incurred.

Table 1. Estimated Costs for Required Idaho Power Local Area Upgrades

Description	**Cost**
Project Substation Site Prep, General Facilities	$800,000
One 345 kV terminal	$1,000,000
Control Area Metering Relocation	$400,000
Network Communications	$750,000
Contingencies & Overheads	$1,030,000
TOTAL	**$3,980,000**

Costs for potential Network Upgrades are not included, but could be sizable.

10.0 Conclusions

The requested interconnection of The Project to Idaho Power's system was studied. The result of this work indicates that the local area Idaho Power transmission system can be upgraded to support this project. The estimated costs of the modifications required, excluding potential network transmission upgrades, are listed in Section 9.0 of this report. These are estimated costs only and final charges to the customer will be based on the actual construction costs incurred.

Next, IPC requires further direction on what the interconnection customer would like to pursue in the System Impact Study. IPC also requires GE PSLF dynamic data about the type of wind turbines the interconnection customer plans to use to perform a detailed stability analysis of the wind project.

APPENDIX A

A-1.0 Method of Study

The System Impact Study inserts the Project up to the maximum requested injection into the selected Western Electric Coordinating Council (WECC) power flow case and then, using GE's Positive Sequence Load Flow (PSLF) analysis tools or Power World Simulator, examines the impacts of the new resource on Idaho Power's system (lines, transformers, etc.) within the study area under various operating/outage scenarios. The WECC and Idaho Power reliability criteria and Idaho Power operating procedures were used to determine the acceptability of the configurations considered. The WECC case is a recent case modified to simulate stressed but reasonable pre-contingency energy transfers utilizing the IPC system.

A-2.0 Acceptability Criteria

The following acceptability criteria were used in the power flow analysis to determine under which system configuration modifications may be required:

> The continuous rating of equipment is assumed to be the normal thermal rating of the equipment. This rating will be as determined by the manufacturer of the equipment or as determined by Idaho Power. Less than or equal to 100% of continuous rating is acceptable.
>
> Idaho Power's Voltage Operating Guidelines were used to determine voltage requirements on the system. This states, in part, that distribution voltages, under normal operating conditions, are to be maintained within plus or minus 5% (0.05 per unit) of nominal everywhere on the feeder. Therefore, voltages greater than or equal to 0.95 pu voltage and less than or equal to 1.05 pu voltage are acceptable.
>
> All customer generation must meet IEEE 519 and ANSI C84.1 Standards.
>
> All other applicable national and Idaho Power standards and prudent utility practices were used to determine the acceptability of the configurations considered.
>
> The stable operation of the system requires an adequate supply of volt-amperes reactive (VARs) to maintain a stable voltage profile under both steady-state and dynamic system conditions. An inadequate supply of VARs will result in voltage decay or even collapse under the worst conditions.

Equipment/line/path ratings used will be those that are in use at the time of the study or that are represented by IPC upgrade projects that are either currently under construction or whose budgets have been approved for construction in the near future. All other potential future ratings are outside the scope of this study. Future transmission changes may, however, affect current facility ratings used in the study.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 11

IDAHO POWER®
An IDACORP Company

March 25, 2010

Randy C. Allphin
Sr. Energy Contract Coordinator
Tel: (208) 388-2614
rallphin@idahopower.com

Exergy Development Group of Idaho
c/o Richardson & O'Leary, PLLC
Attn: Peter Richardson
P.O. Box 7218
Boise, ID 83707

E-mail Copy: peter@richardsonandoleary.com

RE: Letter of Understanding
Rogerson Flats Wind Park, LLC - Proposed Wind Project

Mr. Richardson,

Summarized below is a brief outline of the purchase power agreement, interconnection process and transmission capacity requirements for the proposed Rogerson Flats Wind Park generation project.

Purchase Power Agreement

The project you have described appears to be eligible for a purchase power agreement under the guidelines for a Qualifying Facility as defined by the Public Utilities Regulatory Policies Act of 1978 (PURPA). When your project has met the requirements described below and is therefore eligible for a purchase power agreement, Idaho Power will prepare a purchase power agreement that complies with the current rules and orders that govern these PURPA agreements.

Prior to Idaho Power executing a purchase power agreement it will be required that you have:

1.) Provided documentation that substantiates that the project has filed for interconnection and is in compliance with any payments and/or other requirements specified in the interconnection process applicable to this project and;

2.) Received and accepted an interconnection feasibility study report for this project and;

3.) Returned a signed copy of this letter of understanding and all of the required information to enable Idaho Power to file an application requesting transmission capacity for this project. Completion of the enclosed Transmission Capacity Application Questionnaire will provide the majority of this information and;

4.) Confirmation that the results of the initial transmission capacity application are known and the project accepts these results and intends to continue with the development of the project including, if applicable, execution of a Network Resource Integration Study Agreement in the form enclosed herein.

Interconnection and Transmission Capacity

Your project will be responsible for all costs of physically interconnecting the project to the Idaho Power electrical system and any costs associated with acquiring adequate firm transmission capacity on the Idaho Power transmission system to enable the project's energy to be delivered to Idaho Power customers.

Interconnection

Your project will be required to complete the interconnection process and execute a Generation Interconnection Agreement ("GIA") in accordance with the applicable state and federal requirements.

Transmission Capacity

To sell your project's energy to Idaho Power, your project must be designated as a Network Resource ("DNR").

In order for this project to achieve DNR status, Idaho Power is required to make a request (complete and file an application) and be granted firm transmission capacity from the Idaho Power delivery business unit ("Delivery") to move your project's energy from the physical interconnection point to Idaho Power customers. The project must be granted DNR status no later than 60 days prior to the project delivering any energy to Idaho Power.

Idaho Power will begin this firm transmission capacity application process only after the project has returned a signed copy of this letter of understanding and all of the information required for Idaho Power to file this application (see attached Transmission Capacity Application Questionnaire).

After filing a complete firm transmission capacity application with Delivery, Idaho Power will receive notification back from Delivery within approximately 30 days that: (a) adequate transmission capacity is available for this project without the need to construct upgrades; or (b) a transmission capacity system impact study is required to determine the available transmission capacity and/or required upgrades; or (c) a statement of the required transmission upgrades and the associated costs. Idaho Power will notify the project of this response to the transmission capacity application in a timely manner after the response is received from Delivery.

P O Box 70 Boise, Idaho 83707 1221 W Idaho St. Boise, Idaho 83702

If the response from Delivery is as specified in item (a) (transmission capacity is available), the project will be required to execute a purchase power agreement with Idaho Power within 30 days in order to retain this transmission capacity reservation.

If the response from Delivery is as specified in items (b) or (c) (studies required and/or upgrades required), the project will be required to execute a Network Resource Integration Study Agreement (sample copy attached for your information) and submit all required deposits or fees within 15 days after receiving notification of this requirement in order for Idaho Power to continue the transmission capacity request process. This Network Resource Integration Study Agreement will specify that the project will be responsible for costs incurred by Idaho Power to perform any required studies. If, after the studies are concluded and the costs of upgrades (if any) are known, and the project wishes to continue the pursuit of transmission capacity, the project will also be responsible for all transmission system upgrade costs identified within the studies. The fees and costs will be in the form of both initial deposits as well as actual costs. If at any time after executing the Network Resource Integration Study Agreement the project does not pay any required fees, or elects to stop the transmission study or upgrade process, the project shall be responsible for all costs incurred by Idaho Power in performing the studies or upgrades up to the point of termination of the Network Resource Integration Study Agreement.

Upon successful completion of the above described transmission capacity upgrade study process, a transmission capacity reservation will exist for this project. However, in order to finalize this transmission capacity reservation, a purchase power agreement with Idaho Power must be executed no later than 30 days after the transmission capacity upgrades studies are completed. If the purchase power agreement is not executed by this deadline, the transmission capacity reservation will be released and this process will have to be repeated if the project later requests transmission capacity.

As noted earlier, this transmission capacity acquisition and receipt of the associated Network Resource designation must be completed, at the minimum, 60 days prior to the project delivering any energy to Idaho Power. In addition, the project must provide routine updates to Idaho Power of the expected online date of the generation project to ensure Idaho Power is capable of accepting the energy from the project on the actual date the project comes online.

P O Box 70 Boise, Idaho 83707 1221 W Idaho St. Boise, Idaho 83702

Please return all required information to:

Idaho Power Company
Attn: Randy C. Allphin
P O Box 70
Boise, ID 83707
E-mail: rallphin@idahopower.com

Sincerely,

R C. Allphin

Randy C Allphin
Idaho Power Company

Understood and accepted this 16th day of August, 2010

Signature ____________________

Print Name James T Carkulis

Title President

Rogerson Flats Wind Park, LLC

IDAHO POWER®
An IDACORP Company

March 25, 2010

Randy C. Allphin
Sr. Energy Contract Coordinator
Tel: (208) 388-2614
rallphin@idahopower.com

Exergy Development Group of Idaho
c/o Richardson & O'Leary, PLLC
Attn: Peter Richardson
P.O. Box 7218
Boise, ID 83707

E-mail Copy: peter@richardsonandoleary.com

RE: Letter of Understanding
Jack Ranch Wind Park, LLC - Proposed Wind Project AkA cottonwood wind Park, LLC

Mr. Richardson,

Summarized below is a brief outline of the purchase power agreement, interconnection process and transmission capacity requirements for the proposed Jack Ranch Wind Park generation project.

Purchase Power Agreement

The project you have described appears to be eligible for a purchase power agreement under the guidelines for a Qualifying Facility as defined by the Public Utilities Regulatory Policies Act of 1978 (PURPA). When your project has met the requirements described below and is therefore eligible for a purchase power agreement, Idaho Power will prepare a purchase power agreement that complies with the current rules and orders that govern these PURPA agreements.

Prior to Idaho Power executing a purchase power agreement it will be required that you have:

1.) Provided documentation that substantiates that the project has filed for interconnection and is in compliance with any payments and/or other requirements specified in the interconnection process applicable to this project and;

2.) Received and accepted an interconnection feasibility study report for this project and;

3.) Returned a signed copy of this letter of understanding and all of the required information to enable Idaho Power to file an application requesting transmission capacity for this project. Completion of the enclosed Transmission Capacity Application Questionnaire will provide the majority of this information and;

4.) Confirmation that the results of the initial transmission capacity application are known and the project accepts these results and intends to continue with the development of the project including, if applicable, execution of a Network Resource Integration Study Agreement in the form enclosed herein.

Interconnection and Transmission Capacity

Your project will be responsible for all costs of physically interconnecting the project to the Idaho Power electrical system and any costs associated with acquiring adequate firm transmission capacity on the Idaho Power transmission system to enable the project's energy to be delivered to Idaho Power customers.

Interconnection

Your project will be required to complete the interconnection process and execute a Generation Interconnection Agreement ("GIA") in accordance with the applicable state and federal requirements.

Transmission Capacity

To sell your project's energy to Idaho Power, your project must be designated as a Network Resource ("DNR").

In order for this project to achieve DNR status, Idaho Power is required to make a request (complete and file an application) and be granted firm transmission capacity from the Idaho Power delivery business unit ("Delivery") to move your project's energy from the physical interconnection point to Idaho Power customers. The project must be granted DNR status no later than 60 days prior to the project delivering any energy to Idaho Power.

Idaho Power will begin this firm transmission capacity application process only after the project has returned a signed copy of this letter of understanding and all of the information required for Idaho Power to file this application (see attached Transmission Capacity Application Questionnaire).

After filing a complete firm transmission capacity application with Delivery, Idaho Power will receive notification back from Delivery within approximately 30 days that: (a) adequate transmission capacity is available for this project without the need to construct upgrades; or (b) a transmission capacity system impact study is required to determine the available transmission capacity and/or required upgrades; or (c) a statement of the required transmission upgrades and the associated costs. Idaho Power will notify the project of this response to the transmission capacity application in a timely manner after the response is received from Delivery.

If the response from Delivery is as specified in item (a) (transmission capacity is available), the project will be required to execute a purchase power agreement with Idaho Power within 30 days in order to retain this transmission capacity reservation.

If the response from Delivery is as specified in items (b) or (c) (studies required and/or upgrades required), the project will be required to execute a Network Resource Integration Study Agreement (sample copy attached for your information) and submit all required deposits or fees within 15 days after receiving notification of this requirement in order for Idaho Power to continue the transmission capacity request process. This Network Resource Integration Study Agreement will specify that the project will be responsible for costs incurred by Idaho Power to perform any required studies. If, after the studies are concluded and the costs of upgrades (if any) are known, and the project wishes to continue the pursuit of transmission capacity, the project will also be responsible for all transmission system upgrade costs identified within the studies. The fees and costs will be in the form of both initial deposits as well as actual costs. If at any time after executing the Network Resource Integration Study Agreement the project does not pay any required fees, or elects to stop the transmission study or upgrade process, the project shall be responsible for all costs incurred by Idaho Power in performing the studies or upgrades up to the point of termination of the Network Resource Integration Study Agreement.

Upon successful completion of the above described transmission capacity upgrade study process, a transmission capacity reservation will exist for this project. However, in order to finalize this transmission capacity reservation, a purchase power agreement with Idaho Power must be executed no later than 30 days after the transmission capacity upgrades studies are completed. If the purchase power agreement is not executed by this deadline, the transmission capacity reservation will be released and this process will have to be repeated if the project later requests transmission capacity.

As noted earlier, this transmission capacity acquisition and receipt of the associated Network Resource designation must be completed, at the minimum, 60 days prior to the project delivering any energy to Idaho Power. In addition, the project must provide routine updates to Idaho Power of the expected online date of the generation project to ensure Idaho Power is capable of accepting the energy from the project on the actual date the project comes online.

Please return all required information to:

Idaho Power Company
Attn: Randy C. Allphin
P O Box 70
Boise, ID 83707
E-mail: rallphin@idahopower.com

Sincerely,

Randy C Allphin
Idaho Power Company

Understood and accepted this 4 day of August, 2010

Signature ______________________

Print Name ______________________

Title President

Cottonwood Wind Park, LLC
(formerly Jack Ranch Wind Park, LLC)

IDAHO POWER®
An IDACORP Company

March 25, 2010

Randy C. Allphin
Sr. Energy Contract Coordinator
Tel: (208) 388-2614
rallphin@idahopower.com

Exergy Development Group of Idaho
c/o Richardson & O'Leary, PLLC
Attn: Peter Richardson
P.O. Box 7218
Boise, ID 83707

E-mail Copy: peter@richardsonandoleary.com

RE: Letter of Understanding
JR-1, LLC - Proposed Wind Project AKA Deep Creek Wind Park, LLC

Mr. Richardson,

Summarized below is a brief outline of the purchase power agreement, interconnection process and transmission capacity requirements for the proposed JR-1 generation project.

Purchase Power Agreement

The project you have described appears to be eligible for a purchase power agreement under the guidelines for a Qualifying Facility as defined by the Public Utilities Regulatory Policies Act of 1978 (PURPA). When your project has met the requirements described below and is therefore eligible for a purchase power agreement, Idaho Power will prepare a purchase power agreement that complies with the current rules and orders that govern these PURPA agreements.

Prior to Idaho Power executing a purchase power agreement it will be required that you have:

1.) Provided documentation that substantiates that the project has filed for interconnection and is in compliance with any payments and/or other requirements specified in the interconnection process applicable to this project and;

2.) Received and accepted an interconnection feasibility study report for this project and;

3.) Returned a signed copy of this letter of understanding and all of the required information to enable Idaho Power to file an application requesting transmission capacity for this project. Completion of the enclosed Transmission Capacity Application Questionnaire will provide the majority of this information and;

4.) Confirmation that the results of the initial transmission capacity application are known and the project accepts these results and intends to continue with the development of the project including, if applicable, execution of a Network Resource Integration Study Agreement in the form enclosed herein.

Interconnection and Transmission Capacity

Your project will be responsible for all costs of physically interconnecting the project to the Idaho Power electrical system and any costs associated with acquiring adequate firm transmission capacity on the Idaho Power transmission system to enable the project's energy to be delivered to Idaho Power customers.

Interconnection

Your project will be required to complete the interconnection process and execute a Generation Interconnection Agreement ("GIA") in accordance with the applicable state and federal requirements.

Transmission Capacity

To sell your project's energy to Idaho Power, your project must be designated as a Network Resource ("DNR").

In order for this project to achieve DNR status, Idaho Power is required to make a request (complete and file an application) and be granted firm transmission capacity from the Idaho Power delivery business unit ("Delivery") to move your project's energy from the physical interconnection point to Idaho Power customers. The project must be granted DNR status no later than 60 days prior to the project delivering any energy to Idaho Power.

Idaho Power will begin this firm transmission capacity application process only after the project has returned a signed copy of this letter of understanding and all of the information required for Idaho Power to file this application (see attached Transmission Capacity Application Questionnaire).

After filing a complete firm transmission capacity application with Delivery, Idaho Power will receive notification back from Delivery within approximately 30 days that: (a) adequate transmission capacity is available for this project without the need to construct upgrades; or (b) a transmission capacity system impact study is required to determine the available transmission capacity and/or required upgrades; or (c) a statement of the required transmission upgrades and the associated costs. Idaho Power will notify the project of this response to the transmission capacity application in a timely manner after the response is received from Delivery.

If the response from Delivery is as specified in item (a) (transmission capacity is available), the project will be required to execute a purchase power agreement with Idaho Power within 30 days in order to retain this transmission capacity reservation.

If the response from Delivery is as specified in items (b) or (c) (studies required and/or upgrades required), the project will be required to execute a Network Resource Integration Study Agreement (sample copy attached for your information) and submit all required deposits or fees within 15 days after receiving notification of this requirement in order for Idaho Power to continue the transmission capacity request process. This Network Resource Integration Study Agreement will specify that the project will be responsible for costs incurred by Idaho Power to perform any required studies. If, after the studies are concluded and the costs of upgrades (if any) are known, and the project wishes to continue the pursuit of transmission capacity, the project will also be responsible for all transmission system upgrade costs identified within the studies. The fees and costs will be in the form of both initial deposits as well as actual costs. If at any time after executing the Network Resource Integration Study Agreement the project does not pay any required fees, or elects to stop the transmission study or upgrade process, the project shall be responsible for all costs incurred by Idaho Power in performing the studies or upgrades up to the point of termination of the Network Resource Integration Study Agreement.

Upon successful completion of the above described transmission capacity upgrade study process, a transmission capacity reservation will exist for this project. However, in order to finalize this transmission capacity reservation, a purchase power agreement with Idaho Power must be executed no later than 30 days after the transmission capacity upgrades studies are completed. If the purchase power agreement is not executed by this deadline, the transmission capacity reservation will be released and this process will have to be repeated if the project later requests transmission capacity.

As noted earlier, this transmission capacity acquisition and receipt of the associated Network Resource designation must be completed, at the minimum, 60 days prior to the project delivering any energy to Idaho Power. In addition, the project must provide routine updates to Idaho Power of the expected online date of the generation project to ensure Idaho Power is capable of accepting the energy from the project on the actual date the project comes online.

P O Box 70 Boise, Idaho 83707 1221 W Idaho St. Boise, Idaho 83702

Please return all required information to:

Idaho Power Company
Attn: Randy C. Allphin
P O Box 70
Boise, ID 83707
E-mail: rallphin@idahopower.com

Sincerely,

R C. Allphin

Randy C Allphin
Idaho Power Company

Understood and accepted this 10th day of August, 2010

Signature [illegible]

Print Name [illegible]

Title President

Deep Creek Wind Park, LLC
(formerly JR-1, LLC)

IDAHO POWER®
An IDACORP Company

March 25, 2010

Randy C. Allphin
Sr. Energy Contract Coordinator
Tel: (208) 388-2614
rallphin@idahopower.com

Exergy Development Group of Idaho
c/o Richardson & O'Leary, PLLC
Attn: Peter Richardson
P.O. Box 7218
Boise, ID 83707

E-mail Copy: peter@richardsonandoleary.com

RE: Letter of Understanding
Salmon Creek Wind Park, LLC - Proposed Wind Project

Mr. Richardson,

Summarized below is a brief outline of the purchase power agreement, interconnection process and transmission capacity requirements for the proposed Salmon Creek Wind Park generation project.

Purchase Power Agreement

The project you have described appears to be eligible for a purchase power agreement under the guidelines for a Qualifying Facility as defined by the Public Utilities Regulatory Policies Act of 1978 (PURPA). When your project has met the requirements described below and is therefore eligible for a purchase power agreement, Idaho Power will prepare a purchase power agreement that complies with the current rules and orders that govern these PURPA agreements.

Prior to Idaho Power executing a purchase power agreement it will be required that you have:

1.) Provided documentation that substantiates that the project has filed for interconnection and is in compliance with any payments and/or other requirements specified in the interconnection process applicable to this project and;

2.) Received and accepted an interconnection feasibility study report for this project and;

3.) Returned a signed copy of this letter of understanding and all of the required information to enable Idaho Power to file an application requesting transmission capacity for this project. Completion of the enclosed Transmission Capacity Application Questionnaire will provide the majority of this information and;

4.) Confirmation that the results of the initial transmission capacity application are known and the project accepts these results and intends to continue with the development of the project including, if applicable, execution of a Network Resource Integration Study Agreement in the form enclosed herein.

Interconnection and Transmission Capacity

Your project will be responsible for all costs of physically interconnecting the project to the Idaho Power electrical system and any costs associated with acquiring adequate firm transmission capacity on the Idaho Power transmission system to enable the project's energy to be delivered to Idaho Power customers.

Interconnection

Your project will be required to complete the interconnection process and execute a Generation Interconnection Agreement ("GIA") in accordance with the applicable state and federal requirements.

Transmission Capacity

To sell your project's energy to Idaho Power, your project must be designated as a Network Resource ("DNR").

In order for this project to achieve DNR status, Idaho Power is required to make a request (complete and file an application) and be granted firm transmission capacity from the Idaho Power delivery business unit ("Delivery") to move your project's energy from the physical interconnection point to Idaho Power customers. The project must be granted DNR status no later than 60 days prior to the project delivering any energy to Idaho Power.

Idaho Power will begin this firm transmission capacity application process only after the project has returned a signed copy of this letter of understanding and all of the information required for Idaho Power to file this application (see attached Transmission Capacity Application Questionnaire).

After filing a complete firm transmission capacity application with Delivery, Idaho Power will receive notification back from Delivery within approximately 30 days that: (a) adequate transmission capacity is available for this project without the need to construct upgrades; or (b) a transmission capacity system impact study is required to determine the available transmission capacity and/or required upgrades; or (c) a statement of the required transmission upgrades and the associated costs. Idaho Power will notify the project of this response to the transmission capacity application in a timely manner after the response is received from Delivery.

If the response from Delivery is as specified in item (a) (transmission capacity is available), the project will be required to execute a purchase power agreement with Idaho Power within 30 days in order to retain this transmission capacity reservation.

If the response from Delivery is as specified in items (b) or (c) (studies required and/or upgrades required), the project will be required to execute a Network Resource Integration Study Agreement (sample copy attached for your information) and submit all required deposits or fees within 15 days after receiving notification of this requirement in order for Idaho Power to continue the transmission capacity request process. This Network Resource Integration Study Agreement will specify that the project will be responsible for costs incurred by Idaho Power to perform any required studies. If, after the studies are concluded and the costs of upgrades (if any) are known, and the project wishes to continue the pursuit of transmission capacity, the project will also be responsible for all transmission system upgrade costs identified within the studies. The fees and costs will be in the form of both initial deposits as well as actual costs. If at any time after executing the Network Resource Integration Study Agreement the project does not pay any required fees, or elects to stop the transmission study or upgrade process, the project shall be responsible for all costs incurred by Idaho Power in performing the studies or upgrades up to the point of termination of the Network Resource Integration Study Agreement.

Upon successful completion of the above described transmission capacity upgrade study process, a transmission capacity reservation will exist for this project. However, in order to finalize this transmission capacity reservation, a purchase power agreement with Idaho Power must be executed no later than 30 days after the transmission capacity upgrades studies are completed. If the purchase power agreement is not executed by this deadline, the transmission capacity reservation will be released and this process will have to be repeated if the project later requests transmission capacity.

As noted earlier, this transmission capacity acquisition and receipt of the associated Network Resource designation must be completed, at the minimum, 60 days prior to the project delivering any energy to Idaho Power. In addition, the project must provide routine updates to Idaho Power of the expected online date of the generation project to ensure Idaho Power is capable of accepting the energy from the project on the actual date the project comes online.

P O Box 70 Boise, Idaho 83707 1221 W Idaho St. Boise, Idaho 83702

Please return all required information to:

Idaho Power Company
Attn: Randy C. Allphin
P O Box 70
Boise, ID 83707
E-mail: rallphin@idahopower.com

Sincerely,

Randy C Allphin
Idaho Power Company

Understood and accepted this 10th day of August, 2010

Signature

Print Name

Title

Salmon Creek Wind Park, LLC

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 12

INTERCONNECTION SYSTEM IMPACT STUDY AGREEMENT

THIS AGREEMENT is made and entered into this_______________day of 2010, by and between ________________ a __________________ organized and existing under the laws of the State of_____________ ("Interconnection Customer,") and Idaho Power Company - Delivery, a Corporation existing under the laws of the State of Idaho, ("Transmission Provider "). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer, and

WHEREAS, Interconnection Customer desires to interconnect the Large Generating Facility with the Transmission System;

WHEREAS, Transmission Provider has completed an Interconnection Feasibility Study (the "Feasibility Study") and provided the results of said study to Interconnection Customer; and

WHEREAS, Interconnection Customer has requested Transmission Provider to perform an Interconnection System Impact Study to assess the impact of interconnecting the Large Generating Facility to the Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved Large Generator Interconnection Procedures (LGIP).

2.0 Interconnection Customer elects and Transmission Provider shall cause to be performed an Interconnection System Impact Study consistent with Section 7.0 of the LGIP in accordance with the Tariff.

3.0 The scope of the Interconnection System Impact Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interconnection System Impact Study will be based upon the results of the Interconnection Feasibility Study and the technical information provided by Interconnection Customer in the Interconnection Request, subject to any modifications in accordance with Section 4.4 of the LGIP. Transmission Provider reserves the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Customer System Impact Study. If Interconnection Customer modifies its designated Point of Interconnection (POI), Interconnection Request, or the technical information provided therein is modified, the time to complete the Interconnection System Impact Study may be extended.

5.0 The Interconnection System Impact Study report shall provide the following information:

- identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

- identification of any thermal overload or voltage limit violations resulting from the interconnection;

- identification of any instability or inadequately damped response to system disturbances resulting from the interconnection and

- description and non-binding, good-faith estimated cost of facilities required to interconnect the Large Generating Facility to the Transmission System and to address the identified short circuit, instability, and power flow issues.

6.0 Interconnection Customer shall provide a deposit of $50,000 for the performance of the Interconnection System Impact Study. Transmission Provider's good-faith estimate for the time of completion of the Interconnection System Impact Study is 90 days from the date of execution, unless otherwise noted.

Upon receipt of the Interconnection System Impact Study, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection System Impact Study.

Any difference between the deposit and the actual cost of the study shall be paid by or refunded to Interconnection Customer, as appropriate.

7.0 Effective Date, Duration and Termination. This Agreement becomes effective upon execution by all Parties and shall continue until the work required by the Agreement is completed; provided, however, the Interconnection Customer may terminate this Agreement at any time after providing written notice. In addition, if Interconnecting Customer withdraws its application for interconnection, this Agreement shall terminate effective with the date the application for interconnection is withdrawn.

8.0 No Obligation to Complete Generating Facility. Nothing in this Agreement obligates Interconnection Customer to continue or complete development of the Generating Facility or enter into a Large Generator Interconnection Agreement ("LGIA"). A binding agreement and commitment with respect to interconnecting the Large Generating Facility to the Transmission System will only occur upon the execution of an LGIA by Transmission Provider and Interconnection Customer.

9.0 Relationship of the Parties. This Agreement is intended to create an independent contractor relationship between the Parties. It is not to be construed as constituting the Parties as partners, as creating a joint venture, or as creating any other form of legal association or arrangement which would impose liability upon a Party for the act or omission of the other Party.

10.0 Remedies. In no event will Transmission Provider or its respective agents, employees, officers, directors, affiliates or representatives be liable for incidental, special, punitive or consequential damages including but not limited to lost profits, even if the Parties have been advised of the possibility of such damages. Interconnecting Customer agrees that Transmission Provider's liability arising out of this Agreement and the services provided under this Agreement, whether under theories of contract, negligence, tort, strict liability, warranty or equity will not exceed the amounts payable by Interconnecting Customer to Transmission Provider for the services that are the basis of such claim.

11.0 Governing Law. The validity, interpretation and performance of this Agreement shall be governed by the laws of the State of Idaho, without regard to its conflict of law principles; and in addition, shall be subject to all applicable federal laws, regulations and judicial or administrative orders

of the Federal Energy Regulatory Commission. Venue for any action to enforce the terms and conditions of this Agreement shall be in Boise, Idaho.

12.0 Amendment. This Agreement may not be modified except by mutual agreement by a signed document duly executed by both Parties.

13.0 Waiver. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon such Party.

14.0 Severability and Savings Clause. If any provision of this Agreement is held to be void, voidable, contrary to public policy, or unenforceable, that provision will be deemed severable from the Agreement as to the smallest part so held, and the remainder of the Agreement will continue in full effect as if the severed provision had not been included, in which case the Agreement will be construed and interpreted to implement the objectives of the Parties as stated in this Agreement. The Parties agree that neither Party will be deemed the drafter of any term that may subsequently be found to be ambiguous or vague.

15.0 Survival. This Agreement shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, to permit the determination and enforcement of liability obligations arising from acts or events that occurred while this Agreement was in effect.

16.0 Assignment and Subcontracts. This Agreement may not be transferred or assigned by either Party hereto without the prior written consent of the other Party, which such consent will not be unreasonably withheld. Transmission Provider may subcontract any portion of the work required by this Agreement without the permission of the Interconnecting Customer.

17.0 Successors and Assigns. This Agreement shall be binding upon and inure to the benefit of the Parties hereto and their respective successors and permitted assigns. Nothing in this Agreement shall be deemed to confer upon any other person any rights, remedies, obligations or liabilities under or by reason of this Agreement.

18.0 Notices. Any notice required by this Agreement is properly given if submitted in writing and delivered to the individual set forth below in person, delivered to a nationally-recognized overnight courier service properly addressed and with delivery charges prepaid, delivered to the

United States Postal Service properly addressed and with proper postage prepaid, transmitted by facsimile with confirmation of successful transmission, or transmitted by email. Either Party may change at any time the individual authorized to receive notice, an address, telephone number or email address by providing notice to the other Party.

If to Interconnecting Customer, to:	If to the Transmission Provider, to:
______________________________	Idaho Power Company
______________________________	Delivery Business Unit
______________________________	1221 West Idaho Street
______________________________	Boise, ID 83702
______________________________	Attention: Rowena Bishop
______________________________	Telephone: 208/388-2658
______________________________	Fax: 208/388-5504
______________________________	Email: rbishop@idahopower.com

19.0 Entire Agreement. This Agreement and its Attachments constitutes the complete agreement between the Parties concerning its subject matter and supersedes all previous communications, negotiation, and agreements, whether oral or written, with respect to this Agreement. None of the terms or obligations under this Agreement may be changed or waived in any manner whatsoever by an action or inaction of either Party unless in a writing duly executed by the Parties. Any provision of this Agreement which is prohibited or unenforceable in any jurisdiction shall be, as to such jurisdiction, ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions in any jurisdiction, and shall not invalidate or render unenforceable such provision in any other jurisdiction.

20.0 Dispute Resolution. Any dispute between Transmission Provider and Interconnection Customer involving the provisions of this Agreement shall be referred to a senior representative of Transmission Provider and a senior representative of Interconnection Customer for resolution on an informal basis as promptly as practicable.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly-authorized officers or agents on the day and year first above written.

Transmission Provider: Idaho Power Company - Delivery

By: Signed

By: Printed Orlando Ciniglio

Title: Engineering Leader, System Planning

Date: August 11, 2010August 11, 2010

Interconnection Customer: ______________________

By: Signed ______________________

By: Printed ______________________

Title: ______________________

Date: ______________________

Attachment A

ASSUMPTIONS USED IN CONDUCTING THE INTERCONNECTION SYSTEM IMPACT STUDY

The Interconnection System Impact Study will be based upon the results of the Interconnection Feasibility Study, subject to any modifications in accordance with Section 4.4 of the LGIP, and the following assumptions:

Designation of Point of Interconnection and configuration to be studied

A single connection to the Midpoint – Humboldt 345 kV line at the Jack Ranch project site.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 13

System Impact Study Agreement

THIS AGREEMENT is made and entered into this_____day of______________ 2010, by and between____, a _______________________organized and existing under the laws of the State of ________________________________, ("Interconnection Customer,") and Idaho Power Company a Corporation existing under the laws of the State of Idaho, ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer, and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a feasibility study and provided the results of said study to the Interconnection Customer (This recital to be omitted if the Parties have agreed to forego the feasibility study.); and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a system impact study(s) to assess the impact of interconnecting the Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed a system impact study(s) consistent with the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of a system impact study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 A system impact study will be based upon the results of the feasibility study and the technical information provided by Interconnection Customer in the Interconnection Request. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the system impact study. If the Interconnection Customer modifies its designated Point of Interconnection,

Interconnection Request, or the technical information provided therein is modified, the time to complete the system impact study may be extended.

5.0 A system impact study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. A system impact study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. A system impact study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

6.0 A distribution system impact study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.

7.0 Affected Systems may participate in the preparation of a system impact study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon a system impact study that covers potential adverse system impacts on their electric systems, and the Transmission Provider has 20 additional Business Days to complete a system impact study requiring review by Affected Systems.

8.0 If the Transmission Provider uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the system impact study shall consider all generating facilities (and with respect to paragraph 8.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the system impact study is commenced –

8.1 Are directly interconnected with the Transmission Provider's electric system; or

8.2 Are interconnected with Affected Systems and may have an impact on the proposed interconnection; and

8.3 Have a pending higher queued Interconnection Request to interconnect with the Transmission Provider's electric system.

9.0 A distribution system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 30 Business Days after this Agreement is signed by the Parties. A transmission system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 45 Business Days after this Agreement is signed by the Parties, or in accordance with the Transmission Provider's queuing procedures.

10.0 A $10,000 deposit will be required from the Interconnection Customer upon execution of this agreement by the Interconnection Customer.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

Transmission Provider: Idaho Power Company

Signed: Marc Patterson

Printed: Marc Patterson

Title: Leader, T&D Planning

Date: July 27, 2010

Interconnection Customer: ____________________

Signed____________________

Printed____________________

Title____________________

Date____________________

Attachment A
Assumptions Used in Conducting the System Impact Study

The system impact study shall be based upon the results of the feasibility study, subject to any modifications in accordance with the standard Small Generator Interconnection Procedures, and the following assumptions:

1) Designation of Point of Interconnection and configuration to be studied.

   Connecting at 138kV to the Salmon-Wells line approximately 2 miles south of Rogerson, Idaho, and approximately 6 miles west.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

System Impact Study Agreement

THIS AGREEMENT is made and entered into this_____day of______________ 2010, by and between____, a ________________________organized and existing under the laws of the State of ____________________________________, ("Interconnection Customer,") and Idaho Power Company a Corporation existing under the laws of the State of Idaho, ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer, and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a feasibility study and provided the results of said study to the Interconnection Customer (This recital to be omitted if the Parties have agreed to forego the feasibility study.); and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a system impact study(s) to assess the impact of interconnecting the Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed a system impact study(s) consistent with the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of a system impact study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 A system impact study will be based upon the results of the feasibility study and the technical information provided by Interconnection Customer in the Interconnection Request. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the system impact study. If the Interconnection Customer modifies its designated Point of Interconnection,

Interconnection Request, or the technical information provided therein is modified, the time to complete the system impact study may be extended.

5.0 A system impact study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. A system impact study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. A system impact study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

6.0 A distribution system impact study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.

7.0 Affected Systems may participate in the preparation of a system impact study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon a system impact study that covers potential adverse system impacts on their electric systems, and the Transmission Provider has 20 additional Business Days to complete a system impact study requiring review by Affected Systems.

8.0 If the Transmission Provider uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the system impact study shall consider all generating facilities (and with respect to paragraph 8.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the system impact study is commenced –

8.1 Are directly interconnected with the Transmission Provider's electric system; or

8.2 Are interconnected with Affected Systems and may have an impact on the proposed interconnection; and

8.3 Have a pending higher queued Interconnection Request to interconnect with the Transmission Provider's electric system.

9.0 A distribution system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 30 Business Days after this Agreement is signed by the Parties. A transmission system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 45 Business Days after this Agreement is signed by the Parties, or in accordance with the Transmission Provider's queuing procedures.

10.0 A $10,000 deposit will be required from the Interconnection Customer upon execution of this agreement by the Interconnection Customer.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

Transmission Provider: Idaho Power Company

Signed: Marc Patterson

Printed: Marc Patterson

Title: Leader, T&D Planning

Date: July 27, 2010

Interconnection Customer: ____________________

Signed____________________

Printed____________________

Title____________________

Date____________________

Attachment A
Assumptions Used in Conducting the System Impact Study

The system impact study shall be based upon the results of the feasibility study, subject to any modifications in accordance with the standard Small Generator Interconnection Procedures, and the following assumptions:

1) Designation of Point of Interconnection and configuration to be studied.

Connecting at 138 kV to the Salmon-Wells line approximately 2 miles south of Rogerson, Idaho, and approximately 6 miles west.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

System Impact Study Agreement

THIS AGREEMENT is made and entered into this_____day of______________ 2010, by and between_______________________________________, a ______________________organized and existing under the laws of the State of ________________________________, ("Interconnection Customer,") and Idaho Power Company a Corporation existing under the laws of the State of Idaho, ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer, and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a feasibility study and provided the results of said study to the Interconnection Customer (This recital to be omitted if the Parties have agreed to forego the feasibility study.); and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a system impact study(s) to assess the impact of interconnecting the Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed a system impact study(s) consistent with the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of a system impact study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 A system impact study will be based upon the results of the feasibility study and the technical information provided by Interconnection Customer in the Interconnection Request. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the system impact study. If the Interconnection Customer modifies its designated Point of Interconnection,

Interconnection Request, or the technical information provided therein is modified, the time to complete the system impact study may be extended.

5.0 A system impact study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. A system impact study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. A system impact study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

6.0 A distribution system impact study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.

7.0 Affected Systems may participate in the preparation of a system impact study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon a system impact study that covers potential adverse system impacts on their electric systems, and the Transmission Provider has 20 additional Business Days to complete a system impact study requiring review by Affected Systems.

8.0 If the Transmission Provider uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the system impact study shall consider all generating facilities (and with respect to paragraph 8.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the system impact study is commenced –

8.1 Are directly interconnected with the Transmission Provider's electric system; or

8.2 Are interconnected with Affected Systems and may have an impact on the proposed interconnection; and

8.3 Have a pending higher queued Interconnection Request to interconnect with the Transmission Provider's electric system.

9.0 A distribution system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 30 Business Days after this Agreement is signed by the Parties. A transmission system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 45 Business Days after this Agreement is signed by the Parties, or in accordance with the Transmission Provider's queuing procedures.

10.0 A $10,000 deposit will be required from the Interconnection Customer upon execution of this agreement by the Interconnection Customer.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

Transmission Provider: Idaho Power Company

Signed: Marc Patterson

Printed: Marc Patterson

Title: Leader, T&D Planning

Date: ~~July 30, 2010~~

Interconnection Customer: ______________________________

Signed________________________________

Printed________________________________

Title__________________________________

Date__________________________________

Attachment A
Assumptions Used in Conducting the System Impact Study

The system impact study shall be based upon the results of the feasibility study, subject to any modifications in accordance with the standard Small Generator Interconnection Procedures, and the following assumptions:

1) Designation of Point of Interconnection and configuration to be studied.

   Connecting at 138 kV to the Salmon-Wells line approximately 2 miles south of Rogerson, Idaho, and approximately 6 miles west.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 14

System Impact Study Agreement

THIS AGREEMENT is made and entered into this 25th day of August 2010, by and between Exergy Development Group of Idaho, a LLC organized and existing under the laws of the State of Idaho, ("Interconnection Customer,") and Idaho Power Company a Corporation existing under the laws of the State of Idaho, ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer, and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a feasibility study and provided the results of said study to the Interconnection Customer (This recital to be omitted if the Parties have agreed to forego the feasibility study.); and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a system impact study(s) to assess the impact of interconnecting the Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed a system impact study(s) consistent with the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of a system impact study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 A system impact study will be based upon the results of the feasibility study and the technical information provided by Interconnection Customer in the Interconnection Request. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the system impact study. If the Interconnection Customer modifies its designated Point of Interconnection,

Interconnection Request, or the technical information provided therein is modified, the time to complete the system impact study may be extended.

5.0 A system impact study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. A system impact study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. A system impact study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

6.0 A distribution system impact study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.

7.0 Affected Systems may participate in the preparation of a system impact study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon a system impact study that covers potential adverse system impacts on their electric systems, and the Transmission Provider has 20 additional Business Days to complete a system impact study requiring review by Affected Systems.

8.0 If the Transmission Provider uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the system impact study shall consider all generating facilities (and with respect to paragraph 8.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the system impact study is commenced –

8.1 Are directly interconnected with the Transmission Provider's electric system; or

8.2 Are interconnected with Affected Systems and may have an impact on the proposed interconnection; and

8.3 Have a pending higher queued Interconnection Request to interconnect with the Transmission Provider's electric system.

9.0 A distribution system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 30 Business Days after this Agreement is signed by the Parties. A transmission system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 45 Business Days after this Agreement is signed by the Parties, or in accordance with the Transmission Provider's queuing procedures.

10.0 A $10,000 deposit will be required from the Interconnection Customer upon execution of this agreement by the Interconnection Customer.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

Transmission Provider: Idaho Power Company

Signed: Marc Patterson

Printed: Marc Patterson

Title: Leader, T&D Planning

Date: July 27, 2010

Interconnection Customer: Exergy Development Group of Idaho, LLC

Signed

Printed JAMES CARKULIS

Title PRESIDENT

Date 8/25/2010

Attachment A
Assumptions Used in Conducting the System Impact Study

The system impact study shall be based upon the results of the feasibility study, subject to any modifications in accordance with the standard Small Generator Interconnection Procedures, and the following assumptions:

1) Designation of Point of Interconnection and configuration to be studied.

   Connecting at 138kV to the Salmon-Wells line approximately 2 miles south of Rogerson, Idaho, and approximately 6 miles west.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

System Impact Study Agreement

THIS AGREEMENT is made and entered into this 25th day of August 2010, by and between Energy Development Group of Idaho, a LLC organized and existing under the laws of the State of Idaho, ("Interconnection Customer,") and Idaho Power Company a Corporation existing under the laws of the State of Idaho, ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer, and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a feasibility study and provided the results of said study to the Interconnection Customer (This recital to be omitted if the Parties have agreed to forego the feasibility study.); and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a system impact study(s) to assess the impact of interconnecting the Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed a system impact study(s) consistent with the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of a system impact study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 A system impact study will be based upon the results of the feasibility study and the technical information provided by Interconnection Customer in the Interconnection Request. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the system impact study. If the Interconnection Customer modifies its designated Point of Interconnection,

Interconnection Request, or the technical information provided therein is modified, the time to complete the system impact study may be extended.

5.0 A system impact study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. A system impact study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. A system impact study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

6.0 A distribution system impact study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.

7.0 Affected Systems may participate in the preparation of a system impact study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon a system impact study that covers potential adverse system impacts on their electric systems, and the Transmission Provider has 20 additional Business Days to complete a system impact study requiring review by Affected Systems.

8.0 If the Transmission Provider uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the system impact study shall consider all generating facilities (and with respect to paragraph 8.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the system impact study is commenced –

8.1 Are directly interconnected with the Transmission Provider's electric system; or

8.2 Are interconnected with Affected Systems and may have an impact on the proposed interconnection; and

8.3 Have a pending higher queued Interconnection Request to interconnect with the Transmission Provider's electric system.

9.0 A distribution system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 30 Business Days after this Agreement is signed by the Parties. A transmission system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 45 Business Days after this Agreement is signed by the Parties, or in accordance with the Transmission Provider's queuing procedures.

10.0 A $10,000 deposit will be required from the Interconnection Customer upon execution of this agreement by the Interconnection Customer.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

Transmission Provider: Idaho Power Company

Signed: Marc Patterson

Printed: Marc Patterson

Title: Leader, T&D Planning

Date: July 27, 2010

Interconnection Customer: Exergy Development Group of Idaho, LLC

Signed

Printed JAMES CARKULIS

Title PRESIDENT

Date 8/25/2010

Attachment A
Assumptions Used in Conducting the System Impact Study

The system impact study shall be based upon the results of the feasibility study, subject to any modifications in accordance with the standard Small Generator Interconnection Procedures, and the following assumptions:

1) Designation of Point of Interconnection and configuration to be studied.

   Connecting at 138 kV to the Salmon-Wells line approximately 2 miles south of Rogerson, Idaho, and approximately 6 miles west.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

System Impact Study Agreement

THIS AGREEMENT is made and entered into this 16th day of SEPTEMBER 2010, by and between ENERGY DEVELOPMENT GROUP OF IDAHO, a LLC organized and existing under the laws of the State of IDAHO, ("Interconnection Customer,") and Idaho Power Company a Corporation existing under the laws of the State of Idaho, ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer, and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a feasibility study and provided the results of said study to the Interconnection Customer (This recital to be omitted if the Parties have agreed to forego the feasibility study.); and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a system impact study(s) to assess the impact of interconnecting the Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed a system impact study(s) consistent with the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of a system impact study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 A system impact study will be based upon the results of the feasibility study and the technical information provided by Interconnection Customer in the Interconnection Request. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the system impact study. If the Interconnection Customer modifies its designated Point of Interconnection,

Interconnection Request, or the technical information provided therein is modified, the time to complete the system impact study may be extended.

5.0 A system impact study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. A system impact study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. A system impact study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

6.0 A distribution system impact study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.

7.0 Affected Systems may participate in the preparation of a system impact study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon a system impact study that covers potential adverse system impacts on their electric systems, and the Transmission Provider has 20 additional Business Days to complete a system impact study requiring review by Affected Systems.

8.0 If the Transmission Provider uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the system impact study shall consider all generating facilities (and with respect to paragraph 8.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the system impact study is commenced –

8.1 Are directly interconnected with the Transmission Provider's electric system; or

8.2 Are interconnected with Affected Systems and may have an impact on the proposed interconnection; and

8.3 Have a pending higher queued Interconnection Request to interconnect with the Transmission Provider's electric system.

9.0 A distribution system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 30 Business Days after this Agreement is signed by the Parties. A transmission system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 45 Business Days after this Agreement is signed by the Parties, or in accordance with the Transmission Provider's queuing procedures.

10.0 A $10,000 deposit will be required from the Interconnection Customer upon execution of this agreement by the Interconnection Customer.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

Transmission Provider: Idaho Power Company

Signed: Marc Patterson

Printed: Marc Patterson

Title: Leader, T&D Planning

Date: 8/18, 2010 August 18, 2010

Interconnection Customer: EXERGY DEVELOPMENT GROUP OF IDAHO, LLC

Signed

Printed COLLIN RUDEEN ON BEHALF OF JAMES CARKULIS //SS//

Title LEAD PROJECT ENGINEER

Date 9/16/2010

Attachment A
Assumptions Used in Conducting the System Impact Study

The system impact study shall be based upon the results of the feasibility study, subject to any modifications in accordance with the standard Small Generator Interconnection Procedures, and the following assumptions:

1) Designation of Point of Interconnection and configuration to be studied.

   Connecting at 138 kV to the Salmon-Wells line approximately 2 miles south of Rogerson, Idaho, and approximately 6 miles west.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 15

INTERCONNECTION SYSTEM IMPACT STUDY AGREEMENT

THIS AGREEMENT is made and entered into this 253rd day of 2010, by and between EXERGY DEVELOPMENT GROUP OF IDAHO a LLC organized and existing under the laws of the State of IDAHO ("Interconnection Customer,") and Idaho Power Company - Delivery, a Corporation existing under the laws of the State of Idaho, ("Transmission Provider "). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer, and

WHEREAS, Interconnection Customer desires to interconnect the Large Generating Facility with the Transmission System;

WHEREAS, Transmission Provider has completed an Interconnection Feasibility Study (the "Feasibility Study") and provided the results of said study to Interconnection Customer; and

WHEREAS, Interconnection Customer has requested Transmission Provider to perform an Interconnection System Impact Study to assess the impact of interconnecting the Large Generating Facility to the Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved Large Generator Interconnection Procedures (LGIP).

2.0 Interconnection Customer elects and Transmission Provider shall cause to be performed an Interconnection System Impact Study consistent with Section 7.0 of the LGIP in accordance with the Tariff.

3.0 The scope of the Interconnection System Impact Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interconnection System Impact Study will be based upon the results of the Interconnection Feasibility Study and the technical information provided by Interconnection Customer in the Interconnection Request, subject to any modifications in accordance with Section 4.4 of the LGIP. Transmission Provider reserves the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Customer System Impact Study. If Interconnection Customer modifies its designated Point of Interconnection (POI), Interconnection Request, or the technical information provided therein is modified, the time to complete the Interconnection System Impact Study may be extended.

5.0 The Interconnection System Impact Study report shall provide the following information:

- identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

- identification of any thermal overload or voltage limit violations resulting from the interconnection;

- identification of any instability or inadequately damped response to system disturbances resulting from the interconnection and

- description and non-binding, good-faith estimated cost of facilities required to interconnect the Large Generating Facility to the Transmission System and to address the identified short circuit, instability, and power flow issues.

6.0 Interconnection Customer shall provide a deposit of $50,000 for the performance of the Interconnection System Impact Study. Transmission Provider's good-faith estimate for the time of completion of the Interconnection System Impact Study is 90 days from the date of execution, unless otherwise noted.

Upon receipt of the Interconnection System Impact Study, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection System Impact Study.

Any difference between the deposit and the actual cost of the study shall be paid by or refunded to Interconnection Customer, as appropriate.

7.0 Effective Date, Duration and Termination. This Agreement becomes effective upon execution by all Parties and shall continue until the work required by the Agreement is completed; provided, however, the Interconnection Customer may terminate this Agreement at any time after providing written notice. In addition, if Interconnecting Customer withdraws its application for interconnection, this Agreement shall terminate effective with the date the application for interconnection is withdrawn.

8.0 No Obligation to Complete Generating Facility. Nothing in this Agreement obligates Interconnection Customer to continue or complete development of the Generating Facility or enter into a Large Generator Interconnection Agreement ("LGIA"). A binding agreement and commitment with respect to interconnecting the Large Generating Facility to the Transmission System will only occur upon the execution of an LGIA by Transmission Provider and Interconnection Customer.

9.0 Relationship of the Parties. This Agreement is intended to create an independent contractor relationship between the Parties. It is not to be construed as constituting the Parties as partners, as creating a joint venture, or as creating any other form of legal association or arrangement which would impose liability upon a Party for the act or omission of the other Party.

10.0 Remedies. In no event will Transmission Provider or its respective agents, employees, officers, directors, affiliates or representatives be liable for incidental, special, punitive or consequential damages including but not limited to lost profits, even if the Parties have been advised of the possibility of such damages. Interconnecting Customer agrees that Transmission Provider's liability arising out of this Agreement and the services provided under this Agreement, whether under theories of contract, negligence, tort, strict liability, warranty or equity will not exceed the amounts payable by Interconnecting Customer to Transmission Provider for the services that are the basis of such claim.

11.0 Governing Law. The validity, interpretation and performance of this Agreement shall be governed by the laws of the State of Idaho, without regard to its conflict of law principles; and in addition, shall be subject to all applicable federal laws, regulations and judicial or administrative orders

of the Federal Energy Regulatory Commission. Venue for any action to enforce the terms and conditions of this Agreement shall be in Boise, Idaho.

12.0 Amendment. This Agreement may not be modified except by mutual agreement by a signed document duly executed by both Parties.

13.0 Waiver. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon such Party.

14.0 Severability and Savings Clause. If any provision of this Agreement is held to be void, voidable, contrary to public policy, or unenforceable, that provision will be deemed severable from the Agreement as to the smallest part so held, and the remainder of the Agreement will continue in full effect as if the severed provision had not been included, in which case the Agreement will be construed and interpreted to implement the objectives of the Parties as stated in this Agreement. The Parties agree that neither Party will be deemed the drafter of any term that may subsequently be found to be ambiguous or vague.

15.0 Survival. This Agreement shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, to permit the determination and enforcement of liability obligations arising from acts or events that occurred while this Agreement was in effect.

16.0 Assignment and Subcontracts. This Agreement may not be transferred or assigned by either Party hereto without the prior written consent of the other Party, which such consent will not be unreasonably withheld. Transmission Provider may subcontract any portion of the work required by this Agreement without the permission of the Interconnecting Customer.

17.0 Successors and Assigns. This Agreement shall be binding upon and inure to the benefit of the Parties hereto and their respective successors and permitted assigns. Nothing in this Agreement shall be deemed to confer upon any other person any rights, remedies, obligations or liabilities under or by reason of this Agreement.

18.0 Notices. Any notice required by this Agreement is properly given if submitted in writing and delivered to the individual set forth below in person, delivered to a nationally-recognized overnight courier service properly addressed and with delivery charges prepaid, delivered to the

United States Postal Service properly addressed and with proper postage prepaid, transmitted by facsimile with confirmation of successful transmission, or transmitted by email. Either Party may change at any time the individual authorized to receive notice, an address, telephone number or email address by providing notice to the other Party.

If to Interconnecting Customer, to:	If to the Transmission Provider, to:
COLLIN RUDEEN	Idaho Power Company
EXERGY DEVELOPMENT GROUP	Delivery Business Unit
802 W. BANNOCK, STE 1200	1221 West Idaho Street
BOISE, ID 83702	Boise, ID 83702
	Attention: Rowena Bishop
PHONE: (208)336-9793	Telephone: 208/388-2658
FAX: (208)336-9431	Fax: 208/388-5504
EMAIL: CRUDEEN@EXERGYDEVELOPMENT.COM	Email: rbishop@idahopower.com

19.0 Entire Agreement. This Agreement and its Attachments constitutes the complete agreement between the Parties concerning its subject matter and supersedes all previous communications, negotiation, and agreements, whether oral or written, with respect to this Agreement. None of the terms or obligations under this Agreement may be changed or waived in any manner whatsoever by an action or inaction of either Party unless in a writing duly executed by the Parties. Any provision of this Agreement which is prohibited or unenforceable in any jurisdiction shall be, as to such jurisdiction, ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions in any jurisdiction, and shall not invalidate or render unenforceable such provision in any other jurisdiction.

20.0 Dispute Resolution. Any dispute between Transmission Provider and Interconnection Customer involving the provisions of this Agreement shall be referred to a senior representative of Transmission Provider and a senior representative of Interconnection Customer for resolution on an informal basis as promptly as practicable.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly-authorized officers or agents on the day and year first above written.

Transmission Provider: Idaho Power Company - Delivery

By: Signed

By: Printed Orlando Ciniglio

Title: Engineering Leader, System Planning

Date: August 11, 2010August 11, 2010

Interconnection Customer: EXERGY DEVELOPMENT GROUP OF IDAHO, LLC

By: Signed

By: Printed Collin Rudeen on behalf of James Carkulis //SS//

Title: Lead Project Engineer

Date: 9/10/2010

Attachment A

ASSUMPTIONS USED IN CONDUCTING THE INTERCONNECTION SYSTEM IMPACT STUDY

The Interconnection System Impact Study will be based upon the results of the Interconnection Feasibility Study, subject to any modifications in accordance with Section 4.4 of the LGIP, and the following assumptions:

Designation of Point of Interconnection and configuration to be studied

A single connection to the Midpoint – Humboldt 345 kV line at the Jack Ranch project site.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 16

IDAHO POWER®
An IDACORP Company

October 26, 2010

Randy C. Allphin
Senior Energy Contract Coordinator

Exergy Development Group of Idaho, LLC
802 West Bannock
Ste. 1200
Boise, ID 83702

Original: U S Mail

E-mail: Peter Richardson peter@richardsonandoleary.com
James Carkulis jcarkulis@exergydevelopment.com

Re: Rogerson Flats Wind Park Power Transmission Service Request

At this time we have received a response from the Idaho Power transmission group to our request for 20 MWs of transmission capacity for your project. Currently there is <u>no transmission capacity available</u> for your project, therefore transmission upgrades may be required to enable your project to deliver energy to Idaho Power.

As noted in previous letters and documents provided to you, as a PURPA project your project will be responsible for all costs associated with any required interconnection and/or transmission equipment and upgrades to interconnect and integrate your project's energy deliveries into the Idaho Power electrical system.

The first step in determining any potential required transmission upgrades is to perform a transmission system impact study. The initial deposit required to begin this study is $10,000, however we have received requests from 4 other projects to interconnect and make use of the same transmission path, therefore our transmission group has advised they will be doing a single transmission study for this "cluster" of projects. Therefore, at this time your allocation of this initial required deposit is $2,000 (1/5th of the total deposit required). If any of the other projects elect to not proceed with participation in the transmission system impact study, this allocation may be revised to reflect the change in number of participants in this transmission system impact study.

For example –

Currently your project is responsible for $1/5^{th}$ of the initial \$10,000 deposit (\$2,000), if one of the projects elects to not proceed with the transmission system impact study, then your project would be responsible for $1/4^{th}$ of the initial \$10,000 deposit (\$2,500) and so on. I will promptly notify you of any change in the \$2,000 initial deposit requirement.

If additional deposits are required beyond the initial \$10,000 deposit, the allocation of those deposits will be made in the same manner.

The completion of the transmission system impact study will result in identification of required transmission upgrades and estimated cost of those upgrades. At that time an allocation of those costs will be determined based on numerous factors. Some of those cost allocation factors being how many projects elect to proceed and the minimum transmission upgrades required to accommodate the projects.

If you wish for us to proceed with the transmission system impact study for your project please complete and execute the attached Network Resource Integration Study Agreement **no later than November 1, 2010** and make payment of the required deposit as specified within the agreement. Upon receipt of the executed Network Resource Integration Study Agreement and the required deposit, Idaho Power will execute the same agreement and submit the request to the transmission group to begin the transmission system impact study.

If either the executed Network Resource Integration Study Agreement or the deposit is not received by the date listed above, the initial request for transmission capacity for your project will be withdrawn.

If you have any questions please do not hesitate to contact me at (208) 388-2614 or rallphin@idahopower.com.

Sincerely,

R C. Allp

Randy C. Allphin
Senior Energy Contract Coordinator

Cc: (IPCo) Donovan Walker

IDAHO POWER®
An IDACORP Company

October 26, 2010

Randy C. Allphin
Senior Energy Contract Coordinator

Exergy Development Group of Idaho, LLC
802 West Bannock
Ste. 1200
Boise, ID 83702

Original: U S Mail

E-mail: Peter Richardson peter@richardsonandoleary.com
James Carkulis jcarkulis@exergydevelopment.com

Re: Cottonwood Wind Park Power Transmission Service Request

At this time we have received a response from the Idaho Power transmission group to our request for 20 MWs of transmission capacity for your project. Currently there is <u>no transmission capacity available</u> for your project, therefore transmission upgrades may be required to enable your project to deliver energy to Idaho Power.

As noted in previous letters and documents provided to you, as a PURPA project your project will be responsible for all costs associated with any required interconnection and/or transmission equipment and upgrades to interconnect and integrate your project's energy deliveries into the Idaho Power electrical system.

The first step in determining any potential required transmission upgrades is to perform a transmission system impact study. The initial deposit required to begin this study is $10,000, however we have received requests from 4 other projects to interconnect and make use of the same transmission path, therefore our transmission group has advised they will be doing a single transmission study for this "cluster" of projects. Therefore, at this time your allocation of this initial required deposit is $2,000 (1/5th of the total deposit required). If any of the other projects elect to not proceed with participation in the transmission system impact study, this allocation may be revised to reflect the change in number of participants in this transmission system impact study.

For example –

> Currently your project is responsible for 1/5th of the initial $10,000 deposit ($2,000), if one of the projects elects to not proceed with the transmission system impact study, then your project would be responsible for 1/4th of the initial $10,000 deposit ($2,500) and so on. I will promptly notify you of any change in the $2,000 initial deposit requirement.

If additional deposits are required beyond the initial $10,000 deposit, the allocation of those deposits will be made in the same manner.

The completion of the transmission system impact study will result in identification of required transmission upgrades and estimated cost of those upgrades. At that time an allocation of those costs will be determined based on numerous factors. Some of those cost allocation factors being how many projects elect to proceed and the minimum transmission upgrades required to accommodate the projects.

If you wish for us to proceed with the transmission system impact study for your project please complete and execute the attached Network Resource Integration Study Agreement **no later than November 1, 2010** and make payment of the required deposit as specified within the agreement. Upon receipt of the executed Network Resource Integration Study Agreement and the required deposit, Idaho Power will execute the same agreement and submit the request to the transmission group to begin the transmission system impact study.

If either the executed Network Resource Integration Study Agreement or the deposit is not received by the date listed above, the initial request for transmission capacity for your project will be withdrawn.

If you have any questions please do not hesitate to contact me at (208) 388-2614 or rallphin@idahopower.com.

Sincerely,

R C. Allphin

Randy C. Allphin
Senior Energy Contract Coordinator

Cc: (IPCo) Donovan Walker

IDAHO POWER®
An IDACORP Company

October 26, 2010

Randy C. Allphin
Senior Energy Contract Coordinator

Exergy Development Group of Idaho, LLC
802 West Bannock
Ste. 1200
Boise, ID 83702

Original: U S Mail

E-mail: Peter Richardson peter@richardsonandoleary.com
James Carkulis jcarkulis@exergydevelopment.com

Re: Deep Creek Wind Park Power Transmission Service Request

At this time we have received a response from the Idaho Power transmission group to our request for 20 MWs of transmission capacity for your project. Currently there is no transmission capacity available for your project, therefore transmission upgrades may be required to enable your project to deliver energy to Idaho Power.

As noted in previous letters and documents provided to you, as a PURPA project your project will be responsible for all costs associated with any required interconnection and/or transmission equipment and upgrades to interconnect and integrate your project's energy deliveries into the Idaho Power electrical system.

The first step in determining any potential required transmission upgrades is to perform a transmission system impact study. The initial deposit required to begin this study is $10,000, however we have received requests from 4 other projects to interconnect and make use of the same transmission path, therefore our transmission group has advised they will be doing a single transmission study for this "cluster" of projects. Therefore, at this time your allocation of this initial required deposit is $2,000 (1/5th of the total deposit required). If any of the other projects elect to not proceed with participation in the transmission system impact study, this allocation may be revised to reflect the change in number of participants in this transmission system impact study.

For example –

Currently your project is responsible for 1/5th of the initial $10,000 deposit ($2,000), if one of the projects elects to not proceed with the transmission system impact study, then your project would be responsible for 1/4th of the initial $10,000 deposit ($2,500) and so on. I will promptly notify you of any change in the $2,000 initial deposit requirement.

If additional deposits are required beyond the initial $10,000 deposit, the allocation of those deposits will be made in the same manner.

The completion of the transmission system impact study will result in identification of required transmission upgrades and estimated cost of those upgrades. At that time an allocation of those costs will be determined based on numerous factors. Some of those cost allocation factors being how many projects elect to proceed and the minimum transmission upgrades required to accommodate the projects.

If you wish for us to proceed with the transmission system impact study for your project please complete and execute the attached Network Resource Integration Study Agreement **no later than November 1, 2010** and make payment of the required deposit as specified within the agreement. Upon receipt of the executed Network Resource Integration Study Agreement and the required deposit, Idaho Power will execute the same agreement and submit the request to the transmission group to begin the transmission system impact study.

If either the executed Network Resource Integration Study Agreement or the deposit is not received by the date listed above, the initial request for transmission capacity for your project will be withdrawn.

If you have any questions please do not hesitate to contact me at (208) 388-2614 or rallphin@idahopower.com.

Sincerely,

R C. Allpn

Randy C. Allphin
Senior Energy Contract Coordinator

Cc: (IPCo) Donovan Walker

IDAHO POWER®
An IDACORP Company

October 26, 2010

Randy C. Allphin
Senior Energy Contract Coordinator

Exergy Development Group of Idaho, LLC
802 West Bannock
Ste. 1200
Boise, ID 83702

Original: U S Mail

E-mail: Peter Richardson peter@richardsonandoleary.com
James Carkulis jcarkulis@exergydevelopment.com

Re: Salmon Creek Wind Park Power Transmission Service Request

At this time we have received a response from the Idaho Power transmission group to our request for 20 MWs of transmission capacity for your project. Currently there is no transmission capacity available for your project, therefore transmission upgrades may be required to enable your project to deliver energy to Idaho Power.

As noted in previous letters and documents provided to you, as a PURPA project your project will be responsible for all costs associated with any required interconnection and/or transmission equipment and upgrades to interconnect and integrate your project's energy deliveries into the Idaho Power electrical system.

The first step in determining any potential required transmission upgrades is to perform a transmission system impact study. The initial deposit required to begin this study is $10,000, however we have received requests from 4 other projects to interconnect and make use of the same transmission path, therefore our transmission group has advised they will be doing a single transmission study for this "cluster" of projects. Therefore, at this time your allocation of this initial required deposit is $2,000 ($1/5^{th}$ of the total deposit required). If any of the other projects elect to not proceed with participation in the transmission system impact study, this allocation may be revised to reflect the change in number of participants in this transmission system impact study.

For example –

Currently your project is responsible for 1/5th of the initial $10,000 deposit ($2,000), if one of the projects elects to not proceed with the transmission system impact study, then your project would be responsible for 1/4th of the initial $10,000 deposit ($2,500) and so on. I will promptly notify you of any change in the $2,000 initial deposit requirement.

If additional deposits are required beyond the initial $10,000 deposit, the allocation of those deposits will be made in the same manner.

The completion of the transmission system impact study will result in identification of required transmission upgrades and estimated cost of those upgrades. At that time an allocation of those costs will be determined based on numerous factors. Some of those cost allocation factors being how many projects elect to proceed and the minimum transmission upgrades required to accommodate the projects.

If you wish for us to proceed with the transmission system impact study for your project please complete and execute the attached Network Resource Integration Study Agreement **no later than November 1, 2010** and make payment of the required deposit as specified within the agreement. Upon receipt of the executed Network Resource Integration Study Agreement and the required deposit, Idaho Power will execute the same agreement and submit the request to the transmission group to begin the transmission system impact study.

If either the executed Network Resource Integration Study Agreement or the deposit is not received by the date listed above, the initial request for transmission capacity for your project will be withdrawn.

If you have any questions please do not hesitate to contact me at (208) 388-2614 or rallphin@idahopower.com.

Sincerely,

R C. Allphin

Randy C. Allphin
Senior Energy Contract Coordinator

Cc: (IPCo) Donovan Walker

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 17

Allphin, Randy

From: Allphin, Randy
Sent: Friday, November 12, 2010 7:11 AM
To: 'James Carkulis'
Subject: RE: contractsR

James I am out of town for the next two weeks.

As you are most likely aware, with the joint filing that was made at the commission on Nov 5, Idaho Power will not be executing these agreements with the Published avoided cost in them until we get some rulings or guidance from the commission.

If the commission agrees to the request (reduce eligibility from 10 aMW to 100 KW) most likely there will be some form or grandfathering process that we will need to run your projects through to make the determination if we can ultimately sign them or not.

That being said, if the project or projects is less than 80 MW (FERC PURPA threshold) nothing prevents us from working through the process of negotiating an agreement. As you have suggested, there may be some things we could both negotiate into a contract that may be beneficial for everyone.

Randy

From: James Carkulis [mailto:jcarkulis@exergydevelopment.com]
Sent: Friday, November 12, 2010 6:26 AM
To: Allphin, Randy
Subject: contractsR

Randy:

Let's meet around 10 AM Monday morning. There is probably no reason we cannot move to contract execution on those 3 projects given they shall be standard agreements. I would much prefer to add more 'capacity' solutions if IPCo is open to this, but we should move forward.

Thanks

James

exergy

James T Carkulis
802 W Bannock, 12th Floor Boise, ID 83702
Office: 208.336.9793 | Mobile: 406.459.3013
jcarkulis@exergydevelopment.com
www.exergydevelopment.com

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 18

RECEIVED
NOV 15 2010
By CB

RICHARDSON & O'LEARY, PLLC
ATTORNEYS AT LAW

Peter Richardson

Tel: 208-938-7901 Fax: 208-938-7904
peter@richardsonandoleary.com
P.O. Box 7218 Boise, ID 83707 - 515 N. 27th St. Boise, ID 83702

November 15, 2010

Donovan Walker
Legal Department
Idaho Power Company
1221 West Idaho Street
Boise, Idaho 83702
HAND DELIVERY
Electronic mail dwalker@idahopower.com

Re: Violation of Idaho Code Section 61-702

Dear Mr. Walker:

My client, Exergy Development Group of Idaho, has been pursing PURPA contracts for four wind projects located in Southern Idaho. The projects are on the J. R. Simplot ranch near the Nevada border just north of Jackpot, Nevada. The four projects are known as the Badger Peak, Bonanza Bar, Conner Ridge and Chapin Mountain wind park projects.

Mr. Carkulis has been in contact with Mr. Allphin for many months on these projects and is frustrated at the lack of movement on the Company's part. My client's frustration has been exacerbated by a November 12, 2010, e-mail communication from Mr. Allphin in which he states, "*As you are most likely aware, with the joint filing that was made at the commission on Nov 5, **Idaho Power will not be executing these agreements with the Published avoided cost in them** until we get some rulings or guidance from the commission.*" [Emphasis provided.] This assertion that Idaho Power is now refusing to execute contracts is contrary to law and is a violation of existing Commission orders and Idaho Power's own PURPA tariffs. Failure to execute these contracts will cause my client significant monetary damages because of the delay in proceeding with an executed contract. As you, know time is of the essence with the pending expiration of the federal tax credits at the end of next month. In addition, my client's damages will be greatly enhanced should the Commission grant the pending joint motion and joint petition that is referenced in Mr. Allphin's e-mail communication prior to executing the requested contracts.

I want to remind you of the provisions of Idaho Code Section 61-702 which provides for a private right of action against a regulated utility for damages or injury resulting from the utility's failure to comply with any law, order or decision of the Commission. Idaho Power's assertion that it has unilaterally ceased executing PURPA contracts violates multiple PUC decisions and orders too numerous to enumerate here. For example, in March of this year the Commission issued Order No. 31025 in which it published new avoided cost rates for projects such as Exergy's. That order is the latest ruling from the Commission on the subject and has not been repealed, stayed or otherwise rendered void or inapplicable. It is, in short, the law of the land and cannot be unilaterally disregarded by Idaho Power Company.

Idaho Code Section 61-702 provides:

> In case any public utility shall do, cause to be done or permit to be done, any act, matter or thing prohibited, forbidden or declared to be unlawful, **or shall omit to do any act, matter or thing required to be done, either by the constitution, any law of this state, or any order or decision of the commission**, according to the terms of this act, such public utility **shall be liable to the persons or corporations affected thereby for all loss, damages or injury caused thereby** or resulting therefrom. An action to recover such loss, damage or injury may be brought in any court of competent jurisdiction by any corporation or person.

Emphasis provided.

Be assured that Exergy intends to assert its legal rights to the fullest extent and that Idaho Power's continued refusal to deal with my client will be considered a willful act that may implicate punitive damages.

Also, by copy of this letter, I am requesting that the Idaho Public Utilities Commission and the Idaho Attorney General's office fulfill their respective duties under Idaho Code Section 61-701 which provides:

> **It is hereby the made the duty of the commission to see that the provisions of the constitution and statutes of this state affecting public utilities,** the enforcement of which is not specifically vested in some other officer or tribunal, are enforced and obeyed, and that **violations thereof are promptly prosecuted and penalties due the state therefore recovered and collected** and to this end it may sue in the name of the people of the state of Idaho. Upon the request of the Commission, it shall be the duty of the attorney general or the prosecuting attorney of the proper county, to aid in any investigation, hearing or trial had under the provisions of this act and to institute and prosecute actions or proceedings for the enforcement of the provisions of the constitution and statues

of this state affecting the public utilities and for the punishment of all violations thereof.

Emphasis provided.

Pursuant to Idaho Code Sections 61-703, 704 and Sections 61-706, 707, the violation of Commission Orders subjects Idaho Power to penalties of up to $2,000 per day for each and every offense. For Exergy's four projects Idaho Power is subject to civil penalties of up to $8,000 for every day the Company continues to refuse to execute power purchase agreements pursuant to the Commission's orders.

Exergy and Idaho Power have worked collaboratively over the years. Exergy has been a great partner with Idaho Power since 2004. It has helped move Idaho Power into the renewable energy world. Exergy would hate to see that solid relationship deteriorate. That said, your immediate attention to this matter is required.

Sincerely

Peter Richardson

Cc: Lawrence Wasden, Attorney General of the State of Idaho
Jim Kempton, President Idaho Public Utilities Commission
Don Howell, Chief Counsel Idaho Public Utilities Commission

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 19

IDAHO POWER®
An IDACORP Company

DONOVAN E. WALKER
Senior Counsel
dwalker@idahopower.com

COPY

November 17, 2010

Peter J. Richardson
RICHARDSON & O'LEARY, PLLC
515 North 27th Street
P.O. Box 7218
Boise, Idaho 83702

Re: Your November 15, 2010, Letter Alleging a Violation of Idaho Code Section 61-702

Mr. Richardson:

Thank you for your letter of November 15, 2010. First of all, please let me clarify that it is ***not*** Idaho Power Company's ("Idaho Power" or "Company") position to refuse to sign contracts pursuant to the Public Utility Regulatory Policies Act of 1978 ("PURPA"). In fact, subsequent to the Joint Petition that was filed with the Idaho Public Utilities Commission ("IPUC") on November 5, 2010, Idaho Power has signed and filed seven PURPA contracts containing the current published avoided cost rates for PURPA qualifying facilities ("QF") under 10 average megawatts, seeking approval of the same from the IPUC.

With regard to your client, Mr. Carkulis, Idaho Power can confirm that it received initial inquiries regarding his four new projects in March of this year. On March 25, 2010, Mr. Carkulis was sent, in the ordinary course of business, a standard letter of understanding spelling out the process and asking for the return of certain transmission related information about his projects so that Idaho Power-Power Supply could file the Transmission Service Requests ("TSR") for his projects. Idaho Power did not receive the signed letter of understanding back until August 10, 2010, at which time the TSRs were requested. In October, Idaho Power-Delivery responded to the TSRs stating that a transmission study needed to be completed, which was communicated to Mr. Carkulis, who subsequently paid the required deposit for this study on October 28, 2010.

It was Idaho Power's understanding that Mr. Carkulis wished to get the results of the required interconnection and transmission studies, which will identify the need for and cost of interconnection facilities and possible transmission upgrades, prior to the time at which he would sign a Firm Energy Sales Agreement ("FESA") which would obligate the projects to a Scheduled Operation Date. As you are aware, the FESA contains provisions providing for delay damages should the projects fail to meet the Scheduled Operation Date set forth in the FESA. These delay damages are secured by the requirement to post liquid delay damage security thirty (30) days subsequent to IPUC approval of the FESA. As you are also aware, it is your client's responsibility to work with Idaho Power's Delivery business unit to ensure that sufficient time and resources will be available for Delivery to construct the interconnection facilities, and transmission upgrades if required, in time to allow the projects to achieve the Scheduled Operation Date set forth in the FESA. As Mr. Carkulis has previously been advised, delays in the interconnection or transmission process do not constitute excusable delays in achieving the Scheduled Operation Date, and, if the projects fail to achieve the Scheduled Operation Date at the times specified in the FESA, delay damages will be assessed. It was for this reason that Idaho Power was of the understanding that your client was not yet ready to commit to the execution of a FESA.

If this is not the case, and if your client wishes to proceed forward with the execution of a FESA prior to completion of the interconnection and transmission studies and accept the associated risk thereto, then Idaho Power can send you a draft PURPA Wind FESA that contains the most recent and up-to-date "standard" terms and conditions that have been approved by the IPUC. As you know, there is a certain amount of project specific factual information that you must then insert into the FESA and return to Idaho Power, whereby Idaho Power will then generate a final, executable copy for signatures. Upon execution by both parties, the FESA can then be filed with the IPUC for approval.

It is unfortunate that this misunderstanding was escalated to a formal letter containing allegations that Idaho Power was in violation of Idaho law when in fact it was not, and also unfortunate that you felt the need to disseminate such letter to the Idaho Attorney General and the President of the IPUC. I would have thought that based upon our numerous previous dealings, many of which involved your client, Mr. Carkulis, as well as many other matters, that you could have simply called me to inquire as to the Company's position with regard the negotiation and signing of FESAs. Had you done so, these matters could have been clarified in a more appropriate manner.

Idaho Power has not failed "to comply with any law, order or decision of the Commission" and has not "unilaterally ceased executing PURPA contracts." Idaho Power continues to negotiate, process, execute, and file for IPUC approval PURPA FESAs in the ordinary course of business, just as it had prior to the November 5, 2010, Joint Petition filing. If you would please confirm in writing that your client wishes to move forward at this time with a PURPA FESA and is aware of the risk and responsibility inherent in proceeding forward at this time with the execution of that FESA prior to completion of the interconnection and transmission studies, Idaho Power will send you a draft PURPA Wind FESA as referenced above.

Sincerely,

Donovan E. Walker

DEW:csb
cc: Lawrence G. Wasden, Attorney General ✓
Jim D. Kempton, President Idaho Public Utilities Commission ✓
Donald L. Howell, II, Deputy Attorney General ✓

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 20

RICHARDSON & O'LEARY, PLLC
ATTORNEYS AT LAW

Peter Richardson

Tel: 208-938-7901 Fax: 208-938-7904
peter@richardsonandoleary.com
P.O. Box 7218 Boise, ID 83707 - 515 N. 27th St. Boise, ID 83702

23 November 2010

Via U.S. Mail and Electronic Mail

Donovan Walker
Legal Department
Idaho Power Company
1221 West Idaho Street
Boise, ID 83702

RE: Exergy Projects, Salmon Creek, Rogerson Flats, Cottonwood (formerly Jack Ranch), and Deep Creek (formerly JR-1)

Dear Donovan:

Thank you for our meeting to discuss the PPA requests for the above-referenced wind projects. As you requested, I write to confirm that Exergy, as the developer of these four projects, is willing to sign contracts including the standard $45/kw delay liquidated damages clause prior to completion of the entire interconnection and transmission processes for these projects, including Idaho Power internal processes required to designate the resource as a network resource. Exergy understands that, under the current standard contract Idaho Power would agree to enter into, a delay in achieving the online date caused by the interconnection or transmission processes is a delay which will not excuse a possible trigger in the delay damages clause.

As we agreed, you will provide a suitable agreement for Exergy's projects containing the project-specific information already provided by Exergy. We look forward to receipt of the agreements and your letter acknowledging that Exergy is fully engaged with Idaho Power in the contracting process. It is our hope that it will not be necessary to file a complaint in order to insure our eligibility for the current published avoided cost rates.

Sincerely,

Peter J. Richardson
Richardson & O'Leary PLLC

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 21

IDAHO POWER®
An IDACORP Company

DONOVAN E. WALKER
Senior Counsel
dwalker@idahopower.com

November 24, 2010

VIA E-MAIL

Peter J. Richardson
RICHARDSON & O'LEARY, PLLC
515 North 27th Street
P.O. Box 7218
Boise, Idaho 83702

Re: Exergy Wind Projects: Salmon Creek, Rogerson Flats, Cottonwood (formerly Jack Ranch), and Deep Creek (formerly JR-1)

Mr. Richardson:

Please let this confirm receipt of your November 23, 2010, letter regarding the above-referenced proposed projects subsequent to our November 19, 2010, meeting. With that letter you request, on behalf of your client, that Idaho Power send draft contracts containing the "standard" terms and conditions for a PURPA, less than 10 average megawatts, published avoided cost rate Firm Energy Sales Agreement ("FESA"). With this letter Idaho Power transmits the same, and by so doing acknowledges that Idaho Power and your client are fully engaged in the referred to PURPA contracting process.

Your letter also confirms and acknowledges that your client wishes to move forward with the FESA, including the standard, Idaho Public Utilities Commission ("Commission") approved $45 per kilowatt of project capacity delay security, prior to completion of the interconnection and transmission studies and processes. Further, that your client understands it is their responsibility to work with Idaho Power's Delivery business unit to ensure that sufficient time and resources will be available for Delivery to construct the interconnection facilities, and transmission upgrades if required, in time to allow the projects to achieve the Scheduled Operation Date that the projects will commit themselves to in the FESA. In addition, your client has been advised, and accepts the risk, that delays in the interconnection or transmission process do not constitute excusable delays in achieving the Scheduled Operation Date, and if the projects fail to achieve the Scheduled Operation Date at the times specified in the FESA, delay damages will be assessed, and delay security applied. Please allow me to suggest that special consideration be given to the Scheduled Operation Date selected by the projects for inclusion in the FESA, such that with the information available at this time a date is chosen that has a good probability of providing time for the anticipated interconnection and possible transmission upgrades to be completed.

1221 W. Idaho St. (83702)
P.O. Box 70
Boise, ID 83707

Additionally, given the very large amount of PURPA generation projects that are proposed for integration into Idaho Power's system, as well as the issues raised in the November 5, 2010, Joint Petition filed with the Commission, Idaho Power would like to call your attention to some of the existing terms and conditions that are part of the Commission-approved standard PURPA FESA, as well as part of the Company's approved Tariff Schedule 72, and make certain that both Idaho Power and your clients have a common understanding and meeting of the minds as to the meaning of these terms and conditions prior to executing the FESAs and submitting the same to the Commission for approval.

According to the standard provisions of the FESA (included below for your reference), curtailment without compensation may occur if there is an event of Force Majeure, a Forced Outage, or a temporary disconnection of the Facility in accordance with Tariff Schedule 72. If the generation from your client's facility will have an adverse affect upon Idaho Power's service to its customers, Idaho Power may temporarily disconnect the facility from Idaho Power's transmission/distribution system as specified within Schedule 72, or take such other reasonable steps as Idaho Power deems appropriate. Idaho Power's intent and understanding is that non-compensated curtailment would be exercised when the generation being provided by facilities connected to its system in certain operating conditions exceeds or approaches the minimum load levels of the Company's system such that it may have a detrimental effect upon the Company's ability to manage its thermal, hydro, and other resources in order to meet its obligation to reliably serve loads on its system.

Idaho Power trusts that these provisions are acceptable to you and your clients, as they have been part of the Commission-approved standard FESA, as well as part of the Commission-approved Tariff Schedule 72 for quite some time. Signing and submitting the FESAs to the Commission will evidence your specific acknowledgment that both parties have a common understanding as set out above with regard to the possible curtailment, without compensation, that may occur in certain operating conditions on Idaho Power's system.

Please review the enclosed draft contracts; fill-in or correct any of the project specific, factual information contained therein; and return the draft to Idaho Power so that the Company can then initiate the Sarbanes-Oxley contract approval process and generate an executable draft for signatures.

Sincerely,

Donovan E. Walker

DEW:csb
Enclosures
cc: Randy Allphin

Article XII: Operations, from the FESA states as follows:

12 .1 Communications – Idaho Power and the Seller shall maintain appropriate operating communications through Idaho Power's Designated Dispatch Facility in accordance with Appendix A of this Agreement.

12 .2 Energy Acceptance –

12.2.1 Idaho Power shall be excused from accepting and paying for Net Energy or accepting Inadvertent Energy which would have otherwise been produced by the Facility and delivered by the Seller to the Point of Delivery, if it is prevented from doing so by an event of Force Majeure, Forced Outage or temporary disconnection of the Facility in accordance with Schedule 72. If, for reasons other than an event of Force Majeure or a Forced Outage, a temporary disconnection under Schedule 72 exceeds twenty (20) days, beginning with the twenty-first day of such interruption, curtailment or reduction, Seller will be deemed to be delivering Net Energy at a rate equivalent to the pro rata daily average of the amounts specified for the applicable month in paragraph 6.2. Idaho Power will notify Seller when the interruption, curtailment or reduction is terminated.

12.2.2 If, in the reasonable opinion of Idaho Power, Seller's operation of the Facility or Interconnection Facilities is unsafe or may otherwise adversely affect Idaho Power's equipment, personnel or service to its customers, Idaho Power may temporarily disconnect the Facility from Idaho Power's transmission/distribution system as specified within Schedule 72 or take such other reasonable steps as Idaho Power deems appropriate.

12.2.3 Under no circumstances will the Seller deliver Net Energy and/or Inadvertent Energy from the Facility to the Point of Delivery in an amount that exceeds the Maximum Capacity Amount at any moment in time. Seller's failure to limit deliveries to the Maximum Capacity Amount will be a Material Breach of this Agreement.

12.2.4 If Idaho Power is unable to accept the energy from this Facility and is not excused from accepting the Facility's energy, Idaho Power's damages shall be limited to only the value of the estimated energy that Idaho Power was unable to accept. Idaho Power will have no responsibility to pay for any other costs, lost revenue or consequential damages the Facility may incur.

12.3 Scheduled Maintenance – On or before January 31 of each calendar year, Seller shall submit a written proposed maintenance schedule of significant Facility maintenance for that calendar year and Idaho Power and Seller shall mutually agree as to the acceptability of the proposed schedule. The Parties determination as to the acceptability of the Seller's timetable for scheduled maintenance will take into consideration Prudent Electrical Practices, Idaho Power system requirements and the Seller's preferred schedule. Neither Party shall unreasonably withhold acceptance of the proposed maintenance schedule.

12.4 Maintenance Coordination – The Seller and Idaho Power shall, to the extent practical, coordinate their respective line and Facility maintenance schedules such that they occur simultaneously.

12.5 Contact Prior to Curtailment – Idaho Power will make a reasonable attempt to contact the Seller prior to exercising its rights to interrupt interconnection or curtail deliveries from the Seller's Facility. Seller understands that in the case of emergency circumstances, real time operations of the electrical system, and/or unplanned events Idaho Power may not be able to provide notice to the Seller prior to interruption, curtailment, or reduction of electrical energy deliveries to Idaho Power.

Idaho Power's Schedule 72, Interconnections to Non-Utility Generation, states in pertinent part:

5.3 Temporary Disconnection. Temporary disconnection shall continue only for so long as reasonably necessary under "Good Utility Practice." Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region. Good Utility Practice includes compliance with WECC or NERC requirements. Payment of lost revenue resulting from temporary disconnection shall be governed by the power purchase agreement.

5.3.1 Emergency Conditions. "Emergency Condition" means a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of the Company, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Company's transmission/distribution system, the Company's Interconnection Facilities or the equipment of the Company's customers; or (3) that, in the case of the Seller, is imminently likely (as determined in a nondiscriminatory manner) to cause a material adverse effect on the reliability and security of, or damage to, the Generation Facility or the Seller's Interconnection Facilities. Under Emergency Conditions, either the Company or the Seller may immediately suspend interconnection service and temporarily disconnect the Generation Facility. The Company shall notify the Seller promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Seller's operation of the Generation Facility. The Seller shall notify the Company promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Company's equipment or service to the Company's customers. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of both Parties' facilities and operations, its anticipated duration, and the necessary corrective action.

5.3.2 Routine Maintenance, Construction, and Repair. The Company may interrupt interconnection service or curtail the output of the Seller's Generation Facility and temporarily disconnect the Generation Facility from the Company's transmission/distribution system when necessary for routine maintenance, construction, and repairs on the Company's transmission/distribution system. The Company will make a reasonable attempt to contact the Seller prior to exercising its rights to interrupt interconnection or curtail deliveries from the Seller's Facility. Seller understands that in the case of emergency circumstances, real time operations of the electrical system, and/or unplanned events, the Company may not be able to provide notice to the Seller prior to interruption, curtailment or reduction of electrical energy deliveries to the Company. The Company shall use reasonable efforts to coordinate such reduction or temporary disconnection with the Seller.

5.3.3 Scheduled Maintenance. On or before January 31 of each calendar year, Seller shall submit a written proposed maintenance schedule of significant Facility maintenance for that calendar year and the Company and Seller shall mutually agree as to the acceptability of the proposed schedule. The Parties determination as to the acceptability of the Seller's timetable for scheduled maintenance will take into consideration Good Utility Practices, Idaho Power system requirements and the Seller's preferred schedule. Neither Party shall unreasonably withhold acceptance of the proposed maintenance schedule.

5.3.4 Maintenance Coordination. The Seller and the Company shall, to the extent practical, coordinate their respective transmission/distribution system and Generation Facility maintenance schedules such that they occur simultaneously. Seller shall provide and maintain adequate protective equipment sufficient to prevent damage to the Generation Facility and Seller-furnished Interconnection Facilities. In some cases, some of Seller's protective relays will provide back-up protection for Idaho Power's facilities. In that event, Idaho Power will test such relays annually and Seller will pay the actual cost of such annual testing.

5.3.5 Forced Outages. During any forced outage, the Company may suspend interconnection service to effect immediate repairs on the Company's transmission/distribution system. The Company shall use reasonable efforts to provide the Seller with prior notice. If prior notice is not given, the Company shall, upon request, provide the Seller written documentation after the fact explaining the circumstances of the disconnection.

5.3.6 Adverse Operating Effects. The Company shall notify the Seller as soon as practicable if, based on Good Utility Practice, operation of the Seller's Generation Facility may cause disruption or deterioration of service to other customers served from the same electric system, or if operating the Generation Facility could cause damage to the Company's transmission/distribution system or other affected systems. Supporting documentation used to reach the decision to disconnect shall be provided to the Seller upon request. If, after notice, the Seller fails to remedy the adverse operating effect within a reasonable time, the Company may disconnect the Generation Facility. The Company shall provide the Seller with reasonable notice of such disconnection, unless the provisions of Article 5.3.1 apply.

5.3.7 Modification of the Generation Facility. The Seller must receive written authorization from the Company before making any change to the Generation Facility that may have a material impact on the safety or reliability of the Company's transmission/distribution system. Such authorization shall not be unreasonably withheld. Modifications shall be done in accordance with Good Utility Practice. If the Seller makes such modification without the Company's prior written authorization, the latter shall have the right to temporarily disconnect the Generation Facility.

5.3.8 Reconnection. The Parties shall cooperate with each other to restore the Generation Facility, Interconnection Facilities, and the Company's transmission/distribution system to their normal operating state as soon as reasonably practicable following a temporary disconnection.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 22

RICHARDSON & O'LEARY, PLLC
ATTORNEYS AT LAW
Peter Richardson
Tel: 208-938-7901 Fax: 208-938-7904
peter@richardsonandoleary.com
P.O. Box 7218 Boise, ID 83707 - 515 N. 27th St. Boise, ID 83702

COPY

29 November 2010

Via U.S. Mail and Electronic Mail

Donovan Walker
Legal Department
Idaho Power Company
1221 West Idaho Street
Boise, ID 83702

RE: Exergy Projects, Salmon Creek, Rogerson Flats, Cottonwood (formerly Jack Ranch), and Deep Creek (formerly JR-1)

Dear Donovan:

Thank you for your letter of November 24, 2010, and the draft agreements for the above referenced Exergy projects. Exergy if fully aware of the contracts' provisions and, as you know has successfully developed many projects using the standard Idaho Power contract. Exergy is also fully aware of transmission and interconnection risks, as well as the liquid security provision.

Exergy is ready to execute the agreements and we appreciate the fact that Idaho Power is processing them as quickly as possible, subject only to your standard Sarbanes-Oxley contract approval process.

To that end, enclosed you will find the fully filled out contract for each of the above referenced projects.

Sincerely,

Peter J. Richardson
Richardson & O'Leary PLLC

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 23

GENERATOR INTERCONNECTION
SYSTEM IMPACT STUDY

for integration of the proposed

IPC Project Q#322, #323, & #324

in

TWIN FALLS COUNTY, IDAHO

to the

IDAHO POWER COMPANY ELECTRICAL SYSTEM

for

the

INTERCONNECTION CUSTOMER

DRAFT REPORT

November 29, 2010

JLE

1.0 Introduction

The Interconnection Customer has contracted with Idaho Power Company (IPC) to perform a System Impact Study (SIS) for the integration of IPC Generation Interconnection Project Queue #322, 323, & 324, three 20 MW wind projects (all to be further referred to as The Projects). The Projects are located in IPCs southern service territory in Twin Falls County, Idaho. The new generation will be connected to the IPC 138 kV system at a new station located under the Upper Salmon – Wells 138 kV line. The point of interconnection to IPC will be the customer side of the generator interconnection package.

This report documents the basis for and the results of this SIS for the proposed three 20 MW wind generation projects. It describes the proposed projects, the impact of associated projects and results of all work in the areas of concern.

2.0 Summary

This SIS looks at two items: (1) Local interconnection requirements for the interconnection of The Projects to IPCs Upper Salmon – Wells 138 kV line, and (2) Transient stability of The Projects.

IPC Transmission Network Upgrades may be necessary if firm transmission is required to deliver The Projects generation from the point of interconnection (point of receipt) to a point of delivery. A transmission service request (TSR) will be required to secure transmission rights on the IPC system, either through latent capacity, or Network Upgrades. Either the interconnection customer, or the merchant purchasing the generation from the interconnection customer, will have to make this TSR. Transmission rights are beyond the scope of this Generation Interconnection System Impact Study. **IPC Transmission Network Upgrade costs are not included in this GI SIS, however, costs could be sizeable.**

Local Interconnection Requirements

If firm transmission is required, the Upper Salmon – Blue Gulch 138 kV line (10.2 miles) will have to be rebuilt in order to integrate the first 20 MW (ProjectQ#322) of The Project. The first 20 MW can be integrated with 10 MW of firm transmission and 10 MW of non-firm transmission without the rebuild. This integration will require the addition of an overload mitigation scheme at the point of interconnection. Transmission is only "firm" as far as Upper Salmon; a TSR will be required to secure transmission rights on the remaining IPC system.

In order to integrate the second 20 MW (ProjectQ#323), 40 MW total, the Upper Salmon – Blue Gulch line must be rebuilt. An overload mitigation scheme is not required, and will offer no benefit.

In order to integrate the last 20 MW (ProjectQ#324), 60 MW total, if firm transmission is required, the entire 138 kV transmission line from the point of interconnection to Upper Salmon will have to be rebuilt. The Projects can be integrated with 50 MW of firm transmission and 10 MW of non-firm transmission with the 10.2 mile Upper Salmon – Blue Gulch 138 kV rebuild and an overload mitigation scheme. Transmission is only "firm" as far as Upper Salmon; a TSR will be required to secure transmission rights on the remaining IPC system.

Integration of any of all of The Projects requires the addition of a new substation. IPCs section of the new substation will consist of at least one 138 kV breaker and potentially a building to house protection equipment including the generation interconnection package. The point of interconnection will be on the customer side of the generator interconnection package.

The generation step up transformer will be connected as a solidly grounded wye on the high (transmission) side.

Transient Stability of The Projects

Select outages were studied using GE PSLF software. The stability analysis performed demonstrated that, for the initial conditions and outages examined, the system was stable and damped and that none of the results exceeded the stated voltage or frequency stability criteria on the system external to The Projects. IPC does not anticipate that any additional transmission system modifications will have to be made to arrest or otherwise manage any stability issues as a result of introducing the proposed new resource to the transmission system.

3.0 Scope of Interconnection System Impact Study

The Interconnection System Impact Study was done and prepared in accordance with Idaho Power Company Standard Generator Interconnection Procedures, to provide a detailed evaluation of the interconnection of the proposed generating project to the Idaho Power system. As listed in Section 5.0 of the Interconnection System Impact Study agreement, the Interconnection System Impact Study report provides the following information:

- identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

- identification of any thermal overload or voltage limit violations resulting from the interconnection;

- identification of any instability or inadequately damped response to system disturbances resulting from the interconnection; and

- description and non-binding, good faith estimated cost of facilities required to interconnect the Large Generating Facility to the Transmission System and to address the identified short circuit, stability, and power flow issues.

All other proposed Generation projects prior to this project in the Generator Interconnect queue were considered in this study. A current list of these projects can be found on the Idaho Power web site, **http://www.oatioasis.com/ipco/index.html.**

4.0 Description of Proposed Generating Project

The Projects consist of three 20 MW wind generation projects, ProjectQ#322, #323, and #324.

At a new station, under the Upper Salmon – Wells 138 kV line, the generation will interconnect to the IPC system.

The proposed in-service date for this project is December 2011.

5.0 Local Area 138 kV Facility Upgrades

5.1 Transmission Line Facilities

Idaho Power's Upper Salmon – Wells 138 kV transmission line serves the interconnection area. Due to the age and lack of growth in the area, the Upper Salmon – Wells 138 kV line has deteriorated and upgrades have not been carried out. Due to this, the rating of the line has been recommended at 50 MVA. Considering other projects ahead of The Projects in the IPC Generation Interconnection queue, there is not transmission capacity available on this line to serve The Projects.

There is capacity for one 20 MW project, without extensive upgrades, if load south of the point of interconnection always remains online (load always exceeds 10 MW). If load at Wells were to trip offline, and generation on the Upper Salmon – Wells 138 kV line was peaking, the Upper Salmon – Blue Gulch line would overload beyond the 50 MW limit.

If firm transmission is required, the Upper Salmon – Blue Gulch 138 kV line (10.2 miles) will have to be rebuilt in order to integrate the first 20 MW (ProjectQ#322) of The Project. The first 20 MW can be integrated with 10 MW of firm transmission and 10 MW of non-firm transmission without the rebuild. This integration will require the addition of an overload mitigation scheme at the point of interconnection; transmission flow will be limited to 10 MW north (20 MW generation minus 10 MW assumed load south) from the point of interconnection to Blue Gulch. Transmission is only firm as far as Upper Salmon; a TSR will be required to secure transmission rights on the remaining IPC system.

In order to integrate the second 20 MW (ProjectQ#323), 40 MW total, the Upper Salmon – Blue Gulch line must be rebuilt. An overload mitigation scheme is not required, and will offer no benefit.

In order to integrate the last 20 MW (ProjectQ#324), 60 MW total, if firm transmission is required, the entire 138 kV transmission line from the point of interconnection to Upper Salmon will have to be rebuilt. The Projects can be integrated with 50 MW of firm transmission and 10 MW of non-firm transmission with the 10.2 mile Upper Salmon – Blue Gulch 138 kV rebuild and an overload mitigation scheme. Transmission is only firm as far as Upper Salmon; a TSR will be required to secure transmission rights on the remaining IPC system.

5.2 Substation Facilities

The Projects will be interconnected at a new 138 kV class substation. IPCs section of the new substation will consist of at least one 138 kV breaker and potentially a building to house protection equipment including the generation interconnection package. The point of interconnection will be on the customer side of the generator interconnection package.

The generation step up transformer will be connected as a solidly grounded wye on the high (transmission) side.

Studies indicate that there is adequate short circuit interrupting capability on breakers in the area for the addition of this generation project. Protective relaying and communications upgrades may be required in adjacent substations.

6.0 Operational Considerations

Connecting The Projects to the Upper Salmon – Wells 138 kV line offers some major problems in terms of voltage control. Without absorbing a significant amount of VARs (at least 13 MVARs), the voltage at the point of interconnection exceeds 1.05 per unit. This study assumes that the generators at the three projects will be Type 3 machines, capable of +/- 0.95 operation. The Projects should be capable of +/- 0.95 power factor operation, as measured at the interconnection point, for all MW production levels from zero MW output to full rated MW output. The interconnection customer will be provided a voltage schedule from Idaho Power Grid Operations prior to Commercial Operation of the project. These projects cannot interconnect without +/- 0.95 power factor capability.

If The Projects use units other than Type 3 wind turbine generators, the interconnection customer must work with IPC to determine the amount of switched capacitors/reactors and possible SVC (dynamic VAR) type devices required to interconnect the project and mitigate high voltage concerns.

7.0 Network Integration of The Projects

Depending on where The Project wishes to sell their generation, Network Upgrades may be required to transmit the power from the point of receipt to the point of delivery. A transmission service request will be required to secure transmission rights on the IPC system. Generation Interconnection System Impact Studies cannot allocate transmission service.

In order to utilize the generation on the IPC system, The Projects' generation will be transmitted to IPCs growing Treasure Valley (Boise) area. Midpoint West, an internal IPC transmission path, is a bottleneck between The Projects & Boise. In order to increase Midpoint West an additional 60 MW, a new 230 kV transmission line between Midpoint and the Treasure Valley would be required. At this point, IPC is not considering options for new 230 kV west out of Midpoint as network upgrades. IPC is in the early stages of a 500 kV transmission project known as Gateway West, which will eventually connect Midpoint to the Treasure Valley. Gateway West will increase the transmission capacity of the Midpoint West cut-plane by well over 60 MW, however this project is not scheduled for completion until sometime after 2014. Between The Projects' in-service date and completion of the Midpoint – Treasure Valley portion of the Gateway West project, The Projects would have to operate as a conditional firm resource, available to be tripped offline if there are problems on the system. A transmission service request will be required to secure transmission rights on the IPC system, and this new transmission project.

8.0 Transient Stability of The Projects

Select outages were studied using GE PSLF software. The stability analysis performed demonstrated that, for the initial conditions and outages examined, the system was stable and damped and that none of the results exceeded the stated voltage or frequency stability criteria on the system external to The Projects. IPC does not anticipate that any additional transmission system modifications will have to be made to arrest or otherwise manage any stability issues as a result of introducing the proposed new resource to the transmission system.

9.0 Description and Cost Estimate of Required Facility Upgrades

The following table lists cost estimates of the directly assignable costs for the upgrades needed to accommodate the proposed project. Allowance for funds used during construction (AFUDC) has not been included in the cost estimates since it is assumed that IPC will be provided up-front funding by the Project. No attempt has been made in this study to assign network upgrade costs and not all of the estimated facility costs are necessarily the responsibility of the Project. These are cost estimates only and final charges to the customer will be based on the actual construction costs incurred. Note that this estimate does not include the cost of the customer's equipment.

Table 1. Estimated Costs for Required Idaho Power Local Area Upgrades

Description	Cost
10.2 mile 138 kV line	$5,000,000
Generation Interconnection Package	$250,000
Total Estimated Cost	**$5,250,000**

Costs for potential Network Upgrades are not included, but could be sizable.

10.0 Conclusions

The requested interconnection of ProjectQ#322, #323, & #324 to Idaho Power's system was studied. The result of this work indicates that the local area Idaho Power transmission system can be upgraded to support this project. The estimated costs of the modifications required, excluding potential network transmission upgrades, are listed in Section 9.0 of this report. These are estimated costs only and final charges to the customer will be based on the actual construction costs incurred.

Next, a facility study will be required to look at the requirements from a construction standpoint. The Facility Study will yield a much more detailed and thorough cost estimate.

APPENDIX A

A-1.0 Method of Study

The System Impact Study inserts the Project up to the maximum requested injection into the selected Western Electric Coordinating Council (WECC) power flow case and then, using GE's Positive Sequence Load Flow (PSLF) analysis tools or Power World Simulator, examines the impacts of the new resource on Idaho Power's system (lines, transformers, etc.) within the study area under various operating/outage scenarios. The WECC and Idaho Power reliability criteria and Idaho Power operating procedures were used to determine the acceptability of the configurations considered. The WECC case is a recent case modified to simulate stressed but reasonable pre-contingency energy transfers utilizing the IPC system.

A-2.0 Acceptability Criteria

The following acceptability criteria were used in the power flow analysis to determine under which system configuration modifications may be required:

> The continuous rating of equipment is assumed to be the normal thermal rating of the equipment. This rating will be as determined by the manufacturer of the equipment or as determined by Idaho Power. Less than or equal to 100% of continuous rating is acceptable.
>
> Idaho Power's Voltage Operating Guidelines were used to determine voltage requirements on the system. This states, in part, that distribution voltages, under normal operating conditions, are to be maintained within plus or minus 5% (0.05 per unit) of nominal everywhere on the feeder. Therefore, voltages greater than or equal to 0.95 pu voltage and less than or equal to 1.05 pu voltage are acceptable.
>
> All customer generation must meet IEEE 519 and ANSI C84.1 Standards.
>
> All other applicable national and Idaho Power standards and prudent utility practices were used to determine the acceptability of the configurations considered.
>
> The stable operation of the system requires an adequate supply of volt-amperes reactive (VARs) to maintain a stable voltage profile under both steady-state and dynamic system conditions. An inadequate supply of VARs will result in voltage decay or even collapse under the worst conditions.

Equipment/line/path ratings used will be those that are in use at the time of the study or that are represented by IPC upgrade projects that are either currently under construction or whose budgets have been approved for construction in the near future. All other potential future ratings are outside the scope of this study. Future transmission changes may, however, affect current facility ratings used in the study.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 24

GENERATOR INTERCONNECTION
SYSTEM IMPACT STUDY

for integration of the proposed

IPC Project Q#325, & #327

in

TWIN FALLS COUNTY, IDAHO

to the

IDAHO POWER COMPANY ELECTRICAL SYSTEM

for

the

INTERCONNECTION CUSTOMER

DRAFT REPORT

December 10, 2010

JLE

1.0 Introduction

The Interconnection Customer has contracted with Idaho Power Company (IPC) to perform a System Impact Study (SIS) for the integration of IPC Generation Interconnection Project Queue #325 & 327, a 20 MW wind generation project and 200 MW wind generation project respectively (both to be further referred to as The Projects). The Projects are located in IPCs southern service territory in Twin Falls County, Idaho. The new generation will be interconnected at a new substation (Station325) under the Midpoint – Humboldt 345 kV transmission line. The point of interconnection to IPC will be the customer side of the generator interconnection package.

This report documents the basis for and the results of this SIS for the proposed projects. It describes the proposed projects, the impact of associated projects and results of all work in the areas of concern.

2.0 Summary

This SIS looks at two items: (1) Local interconnection requirements for the interconnection of The Projects to the Midpoint – Humboldt 345 kV line, and (2) Transient stability of The Projects.

IPC Transmission Network Upgrades may be necessary if firm transmission is required to deliver The Projects generation from the point of interconnection (point of receipt) to a point of delivery. A transmission service request (TSR) will be required to secure transmission rights on the IPC system, either through latent capacity, or Network Upgrades. Either the interconnection customer, or the merchant purchasing the generation from the interconnection customer, will have to make this TSR. Transmission rights are beyond the scope of this Generation Interconnection System Impact Study. **IPC Transmission Network Upgrade costs are not included in this GI SIS, however, costs could be sizeable.**

Local Interconnection Requirements

Connecting The Project to the Midpoint – Humboldt 345 kV line will require the following:

1) A new 345/138 kV class substation at the project location.

Capacity Benefit Margin problems exist if the entire 220 MW of wind generation is sold to IPC with only a single connection to the 345 kV system. IPC has no knowledge or where this generation is planned to be sold; this problem will be addressed in an associated Transmission Service Request.

Total Estimated Cost: $3,980,000

More detail is located in Section 5.

The generation step up transformer will be connected as a solidly grounded wye on the high (transmission) side.

Transient Stability of The Projects

Select outages were studied using GE PSLF software. The stability analysis performed demonstrated that, for the initial conditions and outages examined, the system was stable and damped and that none of the results exceeded the stated voltage or frequency stability criteria on the system external to The Projects. IPC does not anticipate that any additional transmission system modifications will have to be made to arrest or otherwise manage any stability issues as a result of introducing the proposed new resource to the transmission system.

3.0 Scope of Interconnection System Impact Study

The Interconnection System Impact Study was done and prepared in accordance with Idaho Power Company Standard Generator Interconnection Procedures, to provide a detailed evaluation of the interconnection of the proposed generating project to the Idaho Power system. As listed in Section 5.0 of the Interconnection System Impact Study agreement, the Interconnection System Impact Study report provides the following information:

- identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;
- identification of any thermal overload or voltage limit violations resulting from the interconnection;
- identification of any instability or inadequately damped response to system disturbances resulting from the interconnection; and
- description and non-binding, good faith estimated cost of facilities required to interconnect the Large Generating Facility to the Transmission System and to address the identified short circuit, stability, and power flow issues.

All other proposed Generation projects prior to this project in the Generator Interconnect queue were considered in this study. A current list of these projects can be found on the Idaho Power web site, **http://www.oatioasis.com/ipco/index.html.**

4.0 Description of Proposed Generating Project

The Projects consist of 220 MW of wind generation. ProjectQ#325 is a 20 MW project and ProjectQ#327 is a 200 MW project.

At a new station, under the Midpoint – Humboldt 345 kV line, the generation will interconnect to the IPC system.

The proposed in-service date for this project is December, 2011.

5.0 Local Area 345 kV Facility Upgrades

5.1 Transmission Line Facilities

Connecting The Project to the Midpoint – Humboldt 345 kV line will require the following:

1) A new 345/138 kV class substation at the project location.

The new 345/138 kV class substation will consist of at least one 345 kV line terminal and a customer owned 345/34.5 kV transformer. The Projects will be added to the Midpoint – Humboldt 345 kV line as a tap. The fact that the line currently utilizes single-pole tripping is not expected to be a problem. The point of interconnection will be the 345 kV breaker on the high side of the 345/34.5 kV transformer.

The IPC – Sierra transmission path's rating limits the south to north transfers across Midpoint – Humboldt to 360 MW. Existing IPC generation utilizes 262.5 MW of this transfer capability, leaving 97.5 MW of capacity available for firm transmission northbound (which may or may not be available to The Project). The 360 MW transfer limit could likely be increased by going through the WECC rating process.

IPCs Capacity Benefit Margin (CBM) is a substantial problem if the entire 220 MW output of The Projects is sold to IPC. IPC holds 330 MW of firm transmission capacity in reserve for the worst case generation loss on the system. With the addition of 220 MW to the Midpoint – Humboldt 345 kV line, 262.5 MW (IPC Existing) + 220 MW (The Project) = 482.5 MW could be either tripped or stranded to the Sierra system with the loss of the Midpoint – Humboldt 345 kV line, creating a new worst-case situation.

NV Energy owns a major share in the Midpoint – Humboldt 345 kV line. These interconnection projects will have to be coordinated between the interconnection customer, Idaho Power, NV Energy, and other planned projects connecting to the Midpoint – Humboldt 345 kV line. Coordination is required to ensure system integrity.

5.2 Substation Facilities

Connecting The Project to the Midpoint – Humboldt 345 kV line will require the following:

1) A new 345/138 kV class substation at the project location.

The new 345/138 kV class substation will consist of at least one 345 kV line terminal and a customer owned 345/34.5 kV transformer. The Projects will be added to the Midpoint – Humboldt 345 kV line as a tap. The fact that the line currently utilizes single-pole tripping is not expected to be a problem. The point of interconnection will be the 345 kV breaker on the high side of the 345/34.5 kV transformer.

The generation step up transformer will be connected as a solidly grounded wye on the high (transmission) side.

Studies indicate that there is adequate short circuit interrupting capability on breakers in the area for the addition of this generation project. Protective relaying and communications upgrades may be required in adjacent substations.

6.0 Operational Considerations

This study assumes that the generators at the three projects will be Type 3 machines, capable of +/- 0.95 operation. The Projects should be capable of +/- 0.95 power factor operation, as measured at the interconnection point, for all MW production levels from zero MW output to full rated MW output. The interconnection customer will be provided a voltage schedule from Idaho Power Grid Operations prior to Commercial Operation of the project. These projects cannot interconnect without +/- 0.95 power factor capability.

Idaho Power and Nevada Power will have to modify the loss calculations on the Midpoint – Humboldt – Coyote – Valmy 345 kV line with the addition of The Project.

If The Projects use units other than Type 3 wind turbine generators, the interconnection customer must work with IPC to determine the amount of switched capacitors/reactors and possible SVC (dynamic VAR) type devices required to interconnect the project.

7.0 Network Integration of The Projects

Depending on where The Projects wish to sell their generation, Network Upgrades may be required to transmit the power from the point of receipt to the point of delivery. A transmission service request will be required to secure transmission rights on the IPC system. Generation Interconnection System Impact Studies cannot allocate transmission service.

8.0 Transient Stability of The Projects

Select outages were studied using GE PSLF software. The stability analysis performed demonstrated that, for the initial conditions and outages examined, the system was stable and damped and that none of the results exceeded the stated voltage or frequency stability criteria on the system external to The Projects. IPC does not anticipate that any additional transmission system modifications will have to be made to arrest or otherwise manage any stability issues as a result of introducing the proposed new resource to the transmission system.

9.0 Description and Cost Estimate of Required Facility Upgrades

The following table lists cost estimates of the directly assignable costs for the upgrades needed to accommodate the proposed project. Allowance for funds used during construction (AFUDC) has not been included in the cost estimates since it is assumed that IPC will be provided up-front funding by the Project. No attempt has been made in this study to assign network upgrade costs and not all of the estimated facility costs are necessarily the responsibility of the Project. These are cost estimates only and final charges to the customer will be based on the actual construction costs incurred. Note that this estimate does not include the cost of the customer's equipment.

Table 1. Estimated Costs for Required Idaho Power Local Area Upgrades

Description	**Cost**
Project Substation Site Prep, General Facilities	$800,000
One 345 kV terminal	$1,000,000
Control Area Metering Relocation	$400,000
Network Communications	$750,000
Contingencies & Overheads	$1,030,000
TOTAL	**$3,980,000**

Costs for potential Network Upgrades are not included, but could be sizable.

10.0 Conclusions

The requested interconnection of ProjectQ#325 & #327 to Idaho Power's system was studied. The result of this work indicates that the local area Idaho Power transmission system can be upgraded to support this project. The estimated costs of the modifications required, excluding potential network transmission upgrades, are listed in Section 9.0 of this report. These are estimated costs only and final charges to the customer will be based on the actual construction costs incurred.

Next, a facility study will be required to look at the requirements from a construction standpoint. The Facility Study will yield a much more detailed and thorough cost estimate.

APPENDIX A

A-1.0 Method of Study

The System Impact Study inserts the Project up to the maximum requested injection into the selected Western Electric Coordinating Council (WECC) power flow case and then, using GE's Positive Sequence Load Flow (PSLF) analysis tools or Power World Simulator, examines the impacts of the new resource on Idaho Power's system (lines, transformers, etc.) within the study area under various operating/outage scenarios. The WECC and Idaho Power reliability criteria and Idaho Power operating procedures were used to determine the acceptability of the configurations considered. The WECC case is a recent case modified to simulate stressed but reasonable pre-contingency energy transfers utilizing the IPC system.

A-2.0 Acceptability Criteria

The following acceptability criteria were used in the power flow analysis to determine under which system configuration modifications may be required:

> The continuous rating of equipment is assumed to be the normal thermal rating of the equipment. This rating will be as determined by the manufacturer of the equipment or as determined by Idaho Power. Less than or equal to 100% of continuous rating is acceptable.
>
> Idaho Power's Voltage Operating Guidelines were used to determine voltage requirements on the system. This states, in part, that distribution voltages, under normal operating conditions, are to be maintained within plus or minus 5% (0.05 per unit) of nominal everywhere on the feeder. Therefore, voltages greater than or equal to 0.95 pu voltage and less than or equal to 1.05 pu voltage are acceptable.
>
> All customer generation must meet IEEE 519 and ANSI C84.1 Standards.
>
> All other applicable national and Idaho Power standards and prudent utility practices were used to determine the acceptability of the configurations considered.
>
> The stable operation of the system requires an adequate supply of volt-amperes reactive (VARs) to maintain a stable voltage profile under both steady-state and dynamic system conditions. An inadequate supply of VARs will result in voltage decay or even collapse under the worst conditions.

Equipment/line/path ratings used will be those that are in use at the time of the study or that are represented by IPC upgrade projects that are either currently under construction or whose budgets have been approved for construction in the near future. All other potential future ratings are outside the scope of this study. Future transmission changes may, however, affect current facility ratings used in the study.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 25

FIRM ENERGY SALES AGREEMENT

BETWEEN

IDAHO POWER COMPANY

AND

ROGERSON FLATS WIND PARK, LLC

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FIRM ENERGY SALES AGREEMENT
(10 aMW or Less)

Project Name: Rogerson Flats Wind Park

Project Number: 31721300

THIS AGREEMENT, entered into on this 10th day of December, 2010 between ROGERSON FLATS WIND PARK, LLC (Seller), and IDAHO POWER COMPANY, an Idaho corporation (Idaho Power), hereinafter sometimes referred to collectively as "Parties" or individually as "Party."

WITNESSETH:

WHEREAS, Seller will design, construct, own, maintain and operate an electric generation facility; and

WHEREAS, Seller wishes to sell, and Idaho Power is willing to purchase, firm electric energy produced by the Seller's Facility.

THEREFORE, In consideration of the mutual covenants and agreements hereinafter set forth, the Parties agree as follows:

ARTICLE I: DEFINITIONS

As used in this Agreement and the appendices attached hereto, the following terms shall have the following meanings:

1.1 "Availability Shortfall Price" - The current month's Mid-Columbia Market Energy Cost minus the current month's All Hours Energy Price specified in paragraph 7.3 of this Agreement. If this calculation results in a value less than 15.00 Mills/kWh the result shall be 15.00 Mills/kWh.

1.2 "Business Days" - means any calendar day that is not a Saturday, a Sunday, or a NERC recognized holiday.

1.3 "Calculated Net Energy Amount" - A monthly estimate, prepared and documented after the fact by Seller, reviewed and accepted by the Buyer that is the calculated monthly maximum energy deliveries (measured in kWh) for each individual wind turbine, totaled for the Facility to determine the total energy that the Facility could have delivered to Idaho Power during that month based upon: (1) each wind turbine's Nameplate Capacity, (2) Sufficient Prime Mover available for use by each wind turbine during the month, (3) incidents of Force Majeure, (4) scheduled maintenance, or (5) incidents of Forced Outages less Losses and Station Use. If the duration of an event characterized as item 3, 4 or 5 above (measured on each individual occurrence and individual wind turbine) lasts for less than 15 minutes, then the event will not be considered in this calculation. The Seller shall collect and maintain actual data to support this calculation and shall keep this data for a minimum of 3 years.

1.4 "Commission" - The Idaho Public Utilities Commission.

1.5 "Contract Year" - The period commencing each calendar year on the same calendar date as the Operation Date and ending 364 days thereafter.

1.6 "Delay Liquidated Damages" – Damages payable to Idaho Power as calculated in paragraph 5.3, 5.4, 5.5 and 5.6.

1.7 "Delay Period" – All days past the Scheduled Operation Date until the Seller's Facility achieves the Operation Date.

1.8 "Delay Price" - The current month's Mid-Columbia Market Energy Cost minus the current month's All Hours Energy Price specified in paragraph 7.3 of this Agreement. If this calculation results in a value less than 0, the result of this calculation will be 0.

1.9 "Designated Dispatch Facility" - Idaho Power's Systems Operations Group, or any subsequent group designated by Idaho Power.

1.10 "Effective Date" – The date stated in the opening paragraph of this Firm Energy Sales Agreement representing the date upon which this Firm Energy Sales Agreement was fully executed by both Parties.

1.11 "Facility" - That electric generation facility described in Appendix B of this Agreement.

1.12 "First Energy Date" - The day commencing at 00:01 hours, Mountain Time, following the day that Seller has satisfied the requirements of Article IV and the Seller begins delivering energy to the Idaho Power electrical system at the Point of Delivery.

1.13 "Forced Outage" – a partial or total reduction of a) the Facility's capacity to produce and/or deliver Net Energy to the Point of Delivery, or b) Idaho Power's ability to accept Net Energy at the Point of Delivery for non-economic reasons, as a result of Idaho Power or Facility: 1) equipment failure which was **not** the result of negligence or lack of preventative maintenance, or 2) responding to a transmission provider curtailment order, or 3) unplanned preventative maintenance to repair equipment that left unrepaired, would result in failure of equipment prior to the planned maintenance period, or 4) planned maintenance or construction of the Facility or electrical lines required to serve this Facility. The Parties shall make commercially reasonable efforts to perform this unplanned preventative maintenance during periods of low wind availability.

1.14 "Heavy Load Hours" – The daily hours beginning at 7:00 am, ending at 11:00 pm Mountain Time, (16 hours) excluding all hours on all Sundays, New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

1.15 "Inadvertent Energy" – Electric energy Seller does not intend to generate. Inadvertent energy is more particularly described in paragraph 7.5 of this Agreement.

1.16 "Interconnection Facilities" - All equipment specified in Idaho Power's Schedule 72.

1.17 "Initial Capacity Determination" – The process by which Idaho Power confirms that under normal or average design conditions the Facility will generate at no more than 10 average MW per month and is therefore eligible to be paid the published rates in accordance with Commission Order No. 29632.

1.18 "Light Load Hours" – The daily hours beginning at 11:00 pm, ending at 7:00 am Mountain Time (8 hours), plus all other hours on all Sundays, New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

1.19 "Losses" – The loss of electrical energy expressed in kilowatt hours (kWh) occurring as a result of the transformation and transmission of energy between the Metering Point and the point the Facility's energy is delivered to the Idaho Power electrical system. The loss calculation formula will be as specified in Appendix B of this Agreement.

1.20 "Market Energy Reference Price" – Eighty-five percent (85%) of the Mid-Columbia Market Energy Cost.

1.21 "Material Breach" – A Default (paragraph 19.2.1) subject to paragraph 19.2.2.

1.22 "Maximum Capacity Amount" – The maximum capacity (MW) of the Facility will be as specified in Appendix B of this Agreement.

1.23 "Mechanical Availability" - The percentage amount calculated by Seller within 5 days after the end of each month of the Facility's monthly actual Net Energy divided by the Facility's Calculated Net Energy Amount for the applicable month. Any damages due as a result of the Seller falling short of the Mechanical Availability Guarantee for each month shall be determined in accordance with paragraph 6.4.4.

1.24 "Mechanical Availability Guarantee" shall be as defined in paragraph 6.4.

1.25 "Metering Equipment" - All equipment specified in Schedule 72, this Agreement and any additional equipment specified in Appendix B required to measure, record and telemeter bi-directional power flows from the Seller's Facility at the Metering Point.

1.26 "Metering Point" - The physical point at which the Metering Equipment is located that enables accurate measurement of the Test Energy and Net Energy deliveries to Idaho Power at the Point of Delivery for this Facility that provides all necessary data to administer this Agreement.

1.27 "Mid- Columbia Market Energy Cost" – The monthly weighted average of the daily on-peak and off-peak Dow Jones Mid-Columbia Index (Dow Jones Mid-C Index) prices for non-firm energy.

If the Dow Jones Mid-Columbia Index price is discontinued by the reporting agency, both Parties will mutually agree upon a replacement index, which is similar to the Dow Jones Mid-Columbia Index. The selected replacement index will be consistent with other similar agreements and a commonly used index by the electrical industry.

1.28 "Nameplate Capacity" –The full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovolt-amperes, kilowatts, volts or other appropriate units. Usually indicated on a nameplate attached to the individual machine or device.

1.29 "Net Energy" – All of the electric energy produced by the Facility, less Station Use, less Losses, expressed in kilowatt hours (kWh) delivered to Idaho Power at the Point of Delivery. Subject to the terms of this Agreement, Seller commits to deliver all Net Energy to Idaho Power at the Point of Delivery for the full term of the Agreement. Net Energy does not include Inadvertent Energy.

1.30 "Operation Date" – The day commencing at 00:01 hours, Mountain Time, following the day that all requirements of paragraph 5.2 have been completed.

1.31 "Point of Delivery" – The location specified in Appendix B, where Idaho Power's and the Seller's electrical facilities are interconnected and the energy from this Facility is delivered to the Idaho Power electrical system.

1.32 "Prudent Electrical Practices" – Those practices, methods and equipment that are commonly and ordinarily used in electrical engineering and operations to operate electric equipment lawfully, safely, dependably, efficiently and economically.

1.33 "Scheduled Operation Date" – The date specified in Appendix B when Seller anticipates achieving the Operation Date. It is expected that the Scheduled Operation Date provided by the Seller shall be a reasonable estimate of the date that the Seller anticipates that the Seller's Facility shall achieve the Operation Date.

1.34 "Schedule 72" – Idaho Power's Tariff No 101, Schedule 72 or its successor schedules as approved by the Commission. The Seller shall be responsible to pay all costs of interconnection and integration of this Facility into the Idaho Power electrical system as specified within Schedule 72 and this Agreement.

1.35 "Season" – The three periods identified in paragraph 6.2.1 of this Agreement.

1.36 "Special Facilities" - Additions or alterations of transmission and/or distribution lines and transformers as described in Schedule 72.

1.37 "Station Use" – Electric energy that is used to operate equipment that is auxiliary or otherwise related to the production of electricity by the Facility.

1.38 "Sufficient Prime Mover" means wind speed that is (1) equal to or greater than the generation unit's manufacturer-specified minimum levels required for the generation unit to produce energy, and (2) equal to or less than the generation unit's manufacturer-specified maximum levels at which the generation unit can safely produce energy.

1.39 "Surplus Energy" – All Net Energy produced by the Seller's Facility and delivered by the Facility to the Idaho Power electrical system prior to the Operation Date.

1.40 "Total Cost of the Facility" - The total cost of structures, equipment and appurtenances.

1.41 "Wind Energy Production Forecast" – A forecast of energy deliveries from this Facility provided by an Idaho Power administered wind forecasting model. The Facility shall be responsible for an allocated portion of the total costs of the forecasting model as specified in Appendix E.

ARTICLE II: NO RELIANCE ON IDAHO POWER

2.1 Seller Independent Investigation - Seller warrants and represents to Idaho Power that in entering into this Agreement and the undertaking by Seller of the obligations set forth herein, Seller has investigated and determined that it is capable of performing hereunder and has not relied upon the advice, experience or expertise of Idaho Power in connection with the transactions contemplated by this Agreement.

2.2 Seller Independent Experts - All professionals or experts including, but not limited to, engineers, attorneys, or accountants that Seller may have consulted or relied on in undertaking the transactions contemplated by this Agreement have been solely those of Seller.

ARTICLE III: WARRANTIES

3.1 No Warranty by Idaho Power - Any review, acceptance or failure to review Seller's design, specifications, equipment or facilities shall not be an endorsement or a confirmation by Idaho Power and Idaho Power makes no warranties, expressed or implied, regarding any aspect of Seller's design, specifications, equipment or facilities, including, but not limited to, safety, durability, reliability, strength, capacity, adequacy or economic feasibility.

3.2 Qualifying Facility Status - Seller warrants that the Facility is a "Qualifying Facility," as that term is used and defined in 18 CFR 292.201 et seq. After initial qualification, Seller will take such steps as may be required to maintain the Facility's Qualifying Facility status during the term of this Agreement and Seller's failure to maintain Qualifying Facility status will be a Material Breach of this Agreement. Idaho Power reserves the right to review the Facility's Qualifying Facility status and associated support and compliance documents at anytime during the term of this Agreement.

ARTICLE IV: CONDITIONS TO ACCEPTANCE OF ENERGY

4.1 Prior to the First Energy Date and as a condition of Idaho Power's acceptance of deliveries of energy from the Seller under this Agreement, Seller shall:

4.1.1 Submit proof to Idaho Power that all licenses, permits or approvals necessary for Seller's operations have been obtained from applicable federal, state or local authorities, including, but not limited to, evidence of compliance with Subpart B, 18 CFR 292.201 et seq. as a certified Qualifying Facility.

4.1.2 Opinion of Counsel - Submit to Idaho Power an Opinion Letter signed by an attorney admitted to practice and in good standing in the State of Idaho providing an opinion that

Seller's licenses, permits and approvals as set forth in paragraph 4.1.1 above are legally and validly issued, are held in the name of the Seller and, based on a reasonable independent review, counsel is of the opinion that Seller is in substantial compliance with said permits as of the date of the Opinion Letter. The Opinion Letter will be in a form acceptable to Idaho Power and will acknowledge that the attorney rendering the opinion understands that Idaho Power is relying on said opinion. Idaho Power's acceptance of the form will not be unreasonably withheld. The Opinion Letter will be governed by and shall be interpreted in accordance with the legal opinion accord of the American Bar Association Section of Business Law (1991).

4.1.3 Initial Capacity Determination - Submit to Idaho Power such data as Idaho Power may reasonably require to perform the Initial Capacity Determination. Such data will include but not be limited to, Nameplate Capacity, equipment specifications, prime mover data, resource characteristics, normal and/or average operating design conditions and Station Use data. Upon receipt of this information, Idaho Power will review the provided data and if necessary, request additional data to complete the Initial Capacity Determination within a reasonable time.

4.1.3.1 If the Maximum Capacity specified in Appendix B of this Agreement and the cumulative manufacture Nameplate Capacity rating of the individual generation units at this Facility is less than 10 MW, the Seller shall submit detailed, manufacturer, verifiable data of the Nameplate Capacity ratings of the actual individual generation units to be installed at this Facility. Upon verification by Idaho Power that the data provided establishes the combined Nameplate Capacity rating of the generation units to be installed at this Facility is less than 10 MW, it will be deemed that the Seller has satisfied the Initial Capacity Determination for this Facility.

4.1.4 Nameplate Capacity – Submit to Idaho Power manufacturer's and engineering documentation that establishes the Nameplate Capacity of each individual generation unit that is included within this entire Facility. Upon receipt of this data, Idaho Power shall review the provided data and determine if the Nameplate Capacity specified is reasonable based upon the manufacturer's specified generation ratings for the specific generation units.

4.1.5 Engineer's Certifications - Submit an executed Engineer's Certification of Design & Construction Adequacy and an Engineer's Certification of Operations and Maintenance (O&M) Policy as described in Commission Order No. 21690. These certificates will be in the form specified in Appendix C but may be modified to the extent necessary to recognize the different engineering disciplines providing the certificates.

4.1.6 Insurance - Submit written proof to Idaho Power of all insurance required in Article XIII.

4.1.7 Interconnection – Provide written confirmation from Idaho Power's delivery business unit that Seller has satisfied all interconnection requirements.

4.1.8 Network Resource Designation – The Seller's Facility has been designated as a network resource capable of delivering firm energy up to the amount of the Maximum Capacity.

4.1.8.1 Seller has provided all information required to enable Idaho Power to file an initial transmission capacity request.

a) Results of the initial transmission capacity request are known and acceptable to the Seller.

b) Seller acknowledges responsibility for all interconnection costs and any costs associated with acquiring adequate firm transmission capacity to enable the project to be classified as an Idaho Power designated firm network resource.

c.) If the Facility is located outside of the Idaho Power service territory, in addition to the above requirements, the Seller must provide evidence that the Seller has acquired firm transmission capacity from all required transmitting entities to deliver the Facility's energy to an acceptable point of delivery on the Idaho Power electrical system.

4.1.9 Written Acceptance – Request and obtain written confirmation from Idaho Power that all conditions to acceptance of energy have been fulfilled. Such written confirmation shall be provided within a commercially reasonable time following the Seller's request and will not be unreasonably withheld by Idaho Power.

ARTICLE V: TERM AND OPERATION DATE

5.1 Term - Subject to the provisions of paragraph 5.2 below, this Agreement shall become effective on the date first written and shall continue in full force and effect for a period of twenty (20) Contract Years from the Operation Date.

5.2 Operation Date - The Operation Date may occur only after the Facility has achieved all of the following:

a) Achieved the First Energy Date.

b) Commission approval of this Agreement in a form acceptable to Idaho Power has been received.

c) Seller has demonstrated to Idaho Power's satisfaction that the Facility is complete and able to provide energy in a consistent, reliable and safe manner.

d) Seller has requested an Operation Date from Idaho Power in a written format.

e) Seller has received written confirmation from Idaho Power of the Operation Date. This confirmation will not be unreasonably withheld by Idaho Power.

5.3 Operation Date Delay - Seller shall cause the Facility to achieve the Operation Date on or before the Scheduled Operation Date. Delays in the interconnection and transmission network upgrade study, design and construction process that **are not** Force Majeure events accepted by both Parties, **shall not** prevent Delay Liquidated Damages from being due and owing as calculated in accordance with this Agreement.

5.3.1 If the Operation Date occurs after the Scheduled Operation Date but on or prior to ninety

(90) days following the Scheduled Operation Date, Seller shall pay Idaho Power Delay Liquidated Damages calculated at the end of each calendar month after the Scheduled Operation Date as follows:

Delay Liquidated Damages are equal to ((Current month's Initial Year Net Energy Amount as specified in paragraph 6.2.1 divided by the number of days in the current month) multiplied by the number of days in the Delay Period in the current month) multiplied by the current month's Delay Price.

5.3.2 If the Operation Date does not occur within ninety (90) days following the Scheduled Operation Date, the Seller shall pay Idaho Power Delay Liquidated Damages, in addition to those provided in paragraph 5.3.1, calculated as follows:

Forty five dollars ($45) multiplied by the Maximum Capacity with the Maximum Capacity being measured in kW.

5.4 If Seller fails to achieve the Operation Date within ninety (90) days following the Scheduled Operation Date, such failure will be a Material Breach and Idaho Power may terminate this Agreement at any time until the Seller cures the Material Breach. Additional Delay Liquidated Damages beyond those calculated in 5.3.1 and 5.3.2 will be calculated and payable using the Delay Liquidated Damage calculation described in 5.3.1 above for all days exceeding 90 days past the Scheduled Operation Date until such time as the Seller cures this Material Breach or Idaho Power terminates this Agreement.

5.5 Seller shall pay Idaho Power any calculated Delay Liquidated Damages within seven (7) days of when Idaho Power calculates and presents any Delay Liquidated Damages billings to the Seller. Seller's failure to pay these damages within the specified time will be a Material Breach of this Agreement and Idaho Power shall draw funds from the Delay Security provided by the Seller in an amount equal to the calculated Delay Liquidated Damages.

5.6 The Parties agree that the damages Idaho Power would incur due to delay in the Facility achieving the Operation Date on or before the Scheduled Operation Date would be difficult or impossible to predict with certainty, and that the Delay Liquidated Damages are an appropriate approximation of such damages.

5.7 Prior to the Seller executing this Agreement, the Seller shall have agreed to and executed a Letter of Understanding with Idaho Power that contains at a minimum the following requirements:

a) Seller has filed for interconnection and is in compliance with all payments and requirements of the interconnection process.

b) Seller has provided all information required to enable Idaho Power to file an initial transmission capacity request.

5.8 Within thirty (30) days of the date of a final non-appealable Commission Order as specified in Article XXI approving this Agreement; Seller shall post liquid security ("Delay Security") in a form as described in Appendix D equal to or exceeding the amount calculated in paragraph 5.8.1. Failure to post this Delay Security in the time specified above will be a Material Breach of this Agreement and Idaho Power may terminate this Agreement.

5.8.1 Delay Security The greater of forty five ($45) multiplied by the Maximum Capacity with the Maximum Capacity being measured in kW or the sum of three month's estimated revenue. Where the estimated three months of revenue is the estimated revenue associated with the first three full months following the estimated Scheduled Operation Date, the estimated kWh of energy production as specified in paragraph 6.2.1 for those three months multiplied by the All Hours Energy Price specified in paragraph 7.3 for each of those three months.

5.8.1.1 In the event (a) Seller provides Idaho Power with certification that (1) a generation interconnection agreement specifying a schedule that will enable this Facility to achieve the Operation Date no later than the Scheduled Operation Date has been completed and the Seller has paid all required interconnection costs, or (2) a generation interconnection agreement is substantially complete and all material costs of interconnection have been identified and agreed upon and the Seller is in compliance with all terms and conditions of the generation interconnection agreement, the Delay Security calculated in accordance with paragraph 5.8.1 will be reduced by ten percent (10%).

5.8.1.2 If the Seller has received a reduction in the calculated Delay Security as specified in paragraph 5.8.1.1 and subsequently (1) at Seller's request, the generation interconnection agreement specified in paragraph 5.8.1.1 is revised and as a result the Facility will not achieve its Operation Date by the Scheduled Operation Date, or (2) if the Seller does not maintain compliance with the generation interconnection agreement, the full amount of the Delay Security as calculated in paragraph 5.8.1 will be subject to reinstatement and will be due and owing within five (5) business days from the date Idaho Power requests reinstatement. Failure to timely reinstate the Delay Security will be a Material Breach of this Agreement.

5.8.2 Idaho Power shall release any remaining security posted hereunder after all calculated Delay Liquidated Damages are paid in full to Idaho Power and the earlier of: 1) thirty (30) days after the Operation Date has been achieved, or 2) sixty (60) days after the Agreement has been terminated.

ARTICLE VI: PURCHASE AND SALE OF NET ENERGY

6.1 Delivery and Acceptance of Net Energy - Except when either Party's performance is excused as provided herein, Idaho Power will purchase and Seller will sell all of the Net Energy to Idaho Power at the Point of Delivery. All Inadvertent Energy produced by the Facility will also be delivered by the Seller to Idaho Power at the Point of Delivery. At no time will the total amount of Net Energy and/or Inadvertent Energy produced by the Facility and delivered by the Seller to the Point of Delivery exceed the Maximum Capacity Amount.

6.2 Net Energy Amounts - Seller intends to produce and deliver Net Energy in the following monthly amounts. These amounts shall be consistent with the Mechanical Availability Guarantee.

6.2.1 Initial Year Monthly Net Energy Amounts:

	Month	kWh
Season 1	March	6,128,553
	April	5,679,690
	May	4,597,609
Season 2	July	3,696,361
	August	3,856,621
	November	5,585,873
	December	6,481,286
Season 3	June	3,903,920
	September	4,001,235
	October	4,922,843
	January	6,302,592
	February	6,416,221

6.3 Unless excused by an event of Force Majeure, Seller's failure to deliver Net Energy in any Contract Year in an amount equal to at least ten percent (10%) of the sum of the Initial Year Monthly Net Energy Amounts as specified in paragraph 6.2 shall constitute an event of default.

6.4 Mechanical Availability Guarantee – After the Operational Date has been established, the Facility shall achieve a minimum monthly Mechanical Availability of 85% for the Facility for each month during the full term of this Agreement (the "Mechanical Availability Guarantee"). Failure to achieve the Mechanical Availability Guarantee shall result in Idaho Power calculating damages as specified in paragraph 6.4.4.

6.4.1 At the same time the Seller provides the Monthly Power Production and Availability Report (Appendix A), the Seller shall provide and certify the calculation of the Facility's current month's Mechanical Availability. The Seller shall include a summary of all information used to calculate the Calculated Net Energy Amount including but not limited to: (a) Forced Outages, (b) Force Majeure events, (c) wind speeds and the impact on generation output, and (c) scheduled maintenance and Station Use information.

6.4.2 The Seller shall maintain and retain for three years detailed documentation supporting the monthly calculation of the Facility's Mechanical Availability.

6.4.3 Idaho Power shall have the right to review and audit the documentation supporting the calculation of the Facility's Mechanical Availability at reasonable times at the Seller's offices.

6.4.4 If the current month's Mechanical Availability is less than the Mechanical Availability Guarantee, damages shall be equal to:

((eighty-five (85) percent of the month's Calculated Net Energy Amount) minus the month's actual Net Energy deliveries) multiplied by the Availability Shortfall Price.

6.4.5 Any damages calculated in paragraph 6.4.4 will be offset against the current month's energy payment. If an unpaid balance remains after the damages are offset against the energy payment, the Seller shall pay in full the remaining balance within thirty (30) days of the date of the invoice.

ARTICLE VII: PURCHASE PRICE AND METHOD OF PAYMENT

7.1 Heavy Load Purchase Price – For all Net Energy received during Heavy Load Hours, Idaho Power will pay the non-levelized energy price in accordance with Commission Order 31025 adjusted in accordance with Commission Order 30415 for Heavy Load Hour Energy deliveries, adjusted in accordance with Commission Order 30488 for the wind integration charge, and with seasonalization factors applied:

	Season 1 - (73.50 %)	Season 2 - (120.00 %)	Season 3 - (100.00 %)
Year	Mills/kWh	Mills/kWh	Mills/kWh
2010	40.52	66.15	55.12
2011	42.80	69.87	58.24
2012	45.32	74.00	61.66
2013	47.71	78.18	64.92
2014	50.29	82.74	68.42
2015	53.05	87.64	72.17
2016	54.64	90.46	74.34
2017	56.20	93.23	76.61
2018	57.90	96.25	79.12
2019	59.57	99.21	81.59

2020	61.29	102.27	84.14
2021	63.33	105.90	87.16
2022	65.46	109.67	90.31
2023	67.67	113.59	93.57
2024	69.97	117.66	96.97
2025	72.35	121.90	100.50
2026	74.38	125.49	103.49
2027	76.62	129.20	106.58
2028	78.96	133.03	109.77
2029	81.38	136.97	113.06
2030	83.87	141.04	116.45
2031	87.22	146.51	121.01
2032	90.15	151.30	125.00
2033	93.19	156.26	129.13

7.2 Light Load Purchase Price – For all Net Energy received during Light Load Hours, Idaho Power will pay the non-levelized energy price in accordance with Commission Order 31025 adjusted in accordance with Commission Order 30415 for Light Load Hour Energy deliveries, adjusted in accordance with Commission Order 30488 for the wind integration charge, and with seasonalization factors applied:

Year	Season 1 - (73.50 %) Mills/kWh	Season 2 - (120.00 %) Mills/kWh	Season 3 - (100.00 %) Mills/kWh
2010	35.59	58.11	48.42
2011	37.88	61.84	51.54
2012	40.40	65.95	54.96
2013	42.79	69.86	58.22
2014	45.37	74.06	61.72
2015	48.13	78.91	65.48
2016	49.72	81.73	67.64
2017	51.28	84.50	69.76
2018	52.97	87.51	72.07
2019	54.65	90.47	74.35
2020	56.37	93.53	76.86
2021	58.41	97.16	79.88
2022	60.54	100.93	83.03
2023	62.74	104.85	86.29
2024	65.04	108.92	89.69
2025	67.43	113.16	93.22
2026	69.45	116.76	96.21
2027	71.55	120.47	99.30

2028	73.70	124.29	102.49
2029	76.03	128.24	105.78
2030	78.52	132.31	109.17
2031	81.87	137.77	113.73
2032	84.80	142.56	117.72
2033	87.84	147.52	121.85

7.3 All Hours Energy Price – The price to be used in the calculation of the Surplus Energy Price and Delay Price shall be the non-levelized energy price in accordance with Commission Order 31025 adjusted in accordance with Commission Order 30488 for the wind integration charge, and with seasonalization factors applied:

Year	Season 1 - (73.50 %) Mills/kWh	Season 2 - (120.00 %) Mills/kWh	Season 3 - (100.00 %) Mills/kWh
2010	38.33	62.57	52.14
2011	40.61	66.30	55.26
2012	43.13	70.42	58.68
2013	45.52	74.33	61.93
2014	48.10	78.85	65.44
2015	50.86	83.75	69.19
2016	52.45	86.58	71.36
2017	54.01	89.35	73.48
2018	55.71	92.36	75.88
2019	57.37	95.32	78.35
2020	59.10	98.38	80.90
2021	61.14	102.01	83.92
2022	63.27	105.78	87.07
2023	65.48	109.70	90.33
2024	67.78	113.77	93.73
2025	70.16	118.01	97.26
2026	72.18	121.60	100.25
2027	74.28	125.31	103.35
2028	76.58	129.14	106.53
2029	79.00	133.09	109.82
2030	81.49	137.16	113.21
2031	84.84	142.62	117.77
2032	87.77	147.41	121.76
2033	90.81	152.37	125.89

7.4 Surplus Energy Price - For all Surplus Energy, Idaho Power shall pay to the Seller the current month's Market Energy Reference Price or the All Hours Energy Price specified in paragraph

7.3, whichever is lower.

7.5 Inadvertent Energy –

7.5.1 Inadvertent Energy is electric energy produced by the Facility, expressed in kWh, which the Seller delivers to Idaho Power at the Point of Delivery that exceeds 10,000 kW multiplied by the hours in the specific month in which the energy was delivered. (For example January contains 744 hours. 744 hours times 10,000 kW = 7,440,000 kWh. Energy delivered in January in excess of 7,440, 000 kWh in this example would be Inadvertent Energy.)

7.5.2 Although Seller intends to design and operate the Facility to generate no more than ten (10) average MW and therefore does not intend to generate Inadvertent Energy, Idaho Power will accept Inadvertent Energy that does not exceed the Maximum Capacity Amount but will not purchase or pay for Inadvertent Energy.

7.6 Payment Due Date – Undisputed Energy payments, less the Wind Energy Production Forecasting Monthly Cost Allocation (MCA) described in Appendix E and any other payments due Idaho Power, will be disbursed to the Seller within 30 days of the date which Idaho Power receives and accepts the documentation of the monthly Mechanical Available Guarantee and the Net Energy actually delivered to Idaho Power as specified in Appendix A.

7.7 Continuing Jurisdiction of the Commission .This Agreement is a special contract and, as such, the rates, terms and conditions contained in this Agreement will be construed in accordance with Idaho Power Company v. Idaho Public Utilities Commission and Afton Energy, Inc., 107 Idaho 781, 693 P.2d 427 (1984), Idaho Power Company v. Idaho Public Utilities Commission, 107 Idaho 1122, 695 P.2d 1 261 (1985), Afton Energy, Inc. v. Idaho Power Company, 111 Idaho 925, 729 P.2d 400 (1986), Section 210 of the Public Utility Regulatory Policies Act of 1978 and 18 CFR §292.303-308.

ARTICLE VIII: ENVIRONMENTAL ATTRIBUTES

8.1 Seller retains ownership under this Agreement of green tags and renewable energy certificates (RECs), or the equivalent environmental attributes, directly associated with the production of energy from the Seller's Facility sold to Idaho Power.

ARTICLE IX: FACILITY AND INTERCONNECTION

9.1 Design of Facility - Seller will design, construct, install, own, operate and maintain the Facility and any Seller-owned Interconnection Facilities so as to allow safe and reliable generation and delivery of Net Energy and Inadvertent Energy to the Idaho Power Point of Delivery for the full term of the Agreement.

9.2 Interconnection Facilities - Except as specifically provided for in this Agreement, the required Interconnection Facilities will be in accordance with Schedule 72, the Generation Interconnection Process and Appendix B. The Seller is responsible for all costs associated with this equipment as specified in Schedule 72 and the Generation Interconnection Process, including but not limited to initial costs incurred by Idaho Power for equipment costs, installation costs and ongoing monthly Idaho Power operations and maintenance expenses.

ARTICLE X: METERING AND TELEMETRY

10.1 Metering - Idaho Power shall, for the account of Seller, provide, install, and maintain Metering and Telemetry Equipment to be located at a mutually agreed upon location to record and measure power flows to Idaho Power in accordance with this Agreement and Schedule 72. The Metering Equipment will be at the location and the type required to measure, record and report the Facility's Net Energy, Station Use, Inadvertent Energy and maximum energy deliveries (kW) at the Point of Delivery in a manner to provide Idaho Power adequate energy measurement data to administer this Agreement and to integrate this Facility's energy production into the Idaho Power electrical system.

10.2 Telemetry – Idaho Power will install, operate and maintain at Seller's expense metering,

communications and telemetry equipment which will be capable of providing Idaho Power with continuous instantaneous telemetry of Seller's Net Energy and Inadvertent Energy produced and delivered to the Idaho Power Point of Delivery to Idaho Power's Designated Dispatch Facility.

ARTICLE XI - RECORDS

11.1 Maintenance of Records - Seller shall maintain at the Facility or such other location mutually acceptable to the Parties adequate total generation, Net Energy, Station Use, Inadvertent Energy and maximum generation (kW) records in a form and content acceptable to Idaho Power.

11.2 Inspection - Either Party, after reasonable notice to the other Party, shall have the right, during normal business hours, to inspect and audit any or all generation, Net Energy, Station Use, Inadvertent Energy and maximum generation (kW) records pertaining to the Seller's Facility.

ARTICLE XII: OPERATIONS

12 .1 Communications - Idaho Power and the Seller shall maintain appropriate operating communications through Idaho Power's Designated Dispatch Facility in accordance with Appendix A of this Agreement.

12 .2 Energy Acceptance –

12.2.1 Idaho Power shall be excused from accepting and paying for Net Energy or accepting Inadvertent Energy which would have otherwise been produced by the Facility and delivered by the Seller to the Point of Delivery, if it is prevented from doing so by an event of Force Majeure, Forced Outage or temporary disconnection of the Facility in accordance with Schedule 72. If, for reasons other than an event of Force Majeure or a Forced Outage, a temporary disconnection under Schedule 72 exceeds twenty (20) days, beginning with the twenty-first day of such interruption, curtailment or reduction, Seller will be deemed to be delivering Net Energy at a rate equivalent to the pro rata daily average of the amounts specified for the applicable month in paragraph 6.2. Idaho Power will notify Seller when the interruption, curtailment or reduction is terminated.

12.2.2 If, in the reasonable opinion of Idaho Power, Seller's operation of the Facility or Interconnection Facilities is unsafe or may otherwise adversely affect Idaho Power's equipment, personnel or service to its customers, Idaho Power may temporarily disconnect the Facility from Idaho Power's transmission/distribution system as specified within Schedule 72 or take such other reasonable steps as Idaho Power deems appropriate.

12.2.3 Under no circumstances will the Seller deliver Net Energy and/or Inadvertent Energy from the Facility to the Point of Delivery in an amount that exceeds the Maximum Capacity Amount at any moment in time. Seller's failure to limit deliveries to the Maximum Capacity Amount will be a Material Breach of this Agreement.

12.2.4 If Idaho Power is unable to accept the energy from this Facility and is not excused from accepting the Facility's energy, Idaho Power's damages shall be limited to only the value of the estimated energy that Idaho Power was unable to accept. Idaho Power will have no responsibility to pay for any other costs, lost revenue or consequential damages the Facility may incur.

12.3 Scheduled Maintenance – On or before January 31st of each calendar year, Seller shall submit a written proposed maintenance schedule of significant Facility maintenance for that calendar year and Idaho Power and Seller shall mutually agree as to the acceptability of the proposed schedule. The Parties determination as to the acceptability of the Seller's timetable for scheduled maintenance will take into consideration Prudent Electrical Practices, Idaho Power system requirements and the Seller's preferred schedule. Neither Party shall unreasonably withhold acceptance of the proposed maintenance schedule.

12.4 Maintenance Coordination - The Seller and Idaho Power shall, to the extent practical, coordinate their respective line and Facility maintenance schedules such that they occur simultaneously.

12.5 Contact Prior to Curtailment - Idaho Power will make a reasonable attempt to contact the Seller prior to exercising its rights to interrupt interconnection or curtail deliveries from the Seller's

Facility. Seller understands that in the case of emergency circumstances, real time operations of the electrical system, and/or unplanned events Idaho Power may not be able to provide notice to the Seller prior to interruption, curtailment, or reduction of electrical energy deliveries to Idaho Power.

ARTICLE XIII: INDEMNIFICATION AND INSURANCE

13.1 Indemnification - Each Party shall agree to hold harmless and to indemnify the other Party, its officers, agents, affiliates, subsidiaries, parent company and employees against all loss, damage, expense and liability to third persons for injury to or death of person or injury to property, proximately caused by the indemnifying Party's (a) construction, ownership, operation or maintenance of, or by failure of, any of such Party's works or facilities used in connection with this Agreement or (b) negligent or intentional acts, errors or omissions. The indemnifying Party shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity. The indemnifying Party shall pay all documented costs, including reasonable attorney fees that may be incurred by the other Party in enforcing this indemnity.

13.2 Insurance - During the term of this Agreement, Seller shall secure and continuously carry the following insurance coverage:

13.2.1 Comprehensive General Liability Insurance for both bodily injury and property damage with limits equal to $1,000,000, each occurrence, combined single limit. The deductible for such insurance shall be consistent with current Insurance Industry Utility practices for similar property.

13.2.2 The above insurance coverage shall be placed with an insurance company with an A.M. Best Company rating of A- or better and shall include:

(a) An endorsement naming Idaho Power as an additional insured and loss payee as applicable; and

(b) A provision stating that such policy shall not be canceled or the limits of liability reduced without sixty (60) days' prior written notice to Idaho Power.

13.3 Seller to Provide Certificate of Insurance - As required in paragraph 4.1.6 herein and annually thereafter, Seller shall furnish Idaho Power a certificate of insurance, together with the endorsements required therein, evidencing the coverage as set forth above.

13.4 Seller to Notify Idaho Power of Loss of Coverage - If the insurance coverage required by paragraph 13.2 shall lapse for any reason, Seller will immediately notify Idaho Power in writing. The notice will advise Idaho Power of the specific reason for the lapse and the steps Seller is taking to reinstate the coverage. Failure to provide this notice and to expeditiously reinstate or replace the coverage will constitute a Material Breach of this Agreement.

ARTICLE XIV: FORCE MAJEURE

14.1 As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the control of the Seller or of Idaho Power which, despite the exercise of due diligence, such Party is unable to prevent or overcome. Force Majeure includes, but is not limited to, acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, or changes in law or regulation occurring after the Effective Date, which, by the exercise of reasonable foresight such party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome. If either Party is rendered wholly or in part unable to perform its obligations under this Agreement because of an event of Force Majeure, both Parties shall be excused from whatever performance is affected by the event of Force Majeure, provided that:

(1) The non-performing Party shall, as soon as is reasonably possible after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence.

(2) The suspension of performance shall be of no greater scope and of no longer duration than is required by the event of Force Majeure.

(3) No obligations of either Party which arose before the occurrence causing the suspension of performance and which could and should have been fully

performed before such occurrence shall be excused as a result of such occurrence.

ARTICLE XV: LIABILITY; DEDICATION

15.1 Limitation of Liability. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. Neither party shall be liable to the other for any indirect, special, consequential, nor punitive damages, except as expressly authorized by this Agreement.

15.2 Dedication. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the Party or the public or affect the status of Idaho Power as an independent public utility corporation or Seller as an independent individual or entity.

ARTICLE XVI: SEVERAL OBLIGATIONS

16.1 Except where specifically stated in this Agreement to be otherwise, the duties, obligations and liabilities of the Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or impose a trust or partnership duty, obligation or liability on or with regard to either Party. Each Party shall be individually and severally liable for its own obligations under this Agreement.

ARTICLE XVII: WAIVER

17.1 Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent default or other matter.

ARTICLE XVIII: CHOICE OF LAWS AND VENUE

18.1 This Agreement shall be construed and interpreted in accordance with the laws of the State of Idaho without reference to its choice of law provisions.

18.2 Venue for any litigation arising out of or related to this Agreement will lie in the District Court of the Fourth Judicial District of Idaho in and for the County of Ada.

ARTICLE XIX: DISPUTES AND DEFAULT

19.1 Disputes - All disputes related to or arising under this Agreement, including, but not limited to, the interpretation of the terms and conditions of this Agreement, will be submitted to the Commission for resolution.

19.2 Notice of Default

19.2.1 Defaults. If either Party fails to perform any of the terms or conditions of this Agreement (an "event of default"), the non-defaulting Party shall cause notice in writing to be given to the defaulting Party, specifying the manner in which such default occurred. If the defaulting Party shall fail to cure such default within the sixty (60) days after service of such notice, or if the defaulting Party reasonably demonstrates to the other Party that the default can be cured within a commercially reasonable time but not within such sixty (60) day period and then fails to diligently pursue such cure, then, the non-defaulting Party may, at its option, terminate this Agreement and/or pursue its legal or equitable remedies.

19.2.2 Material Breaches – The notice and cure provisions in paragraph 19.2.1 do not apply to defaults identified in this Agreement as Material Breaches. Material Breaches must be cured as expeditiously as possible following occurrence of the breach.

19.3 Security for Performance - Prior to the Operation Date and thereafter for the full term of this Agreement, Seller will provide Idaho Power with the following:

19.3.1 Insurance - Evidence of compliance with the provisions of paragraph 13.2. If Seller

fails to comply, such failure will be a Material Breach and may <u>only</u> be cured by Seller supplying evidence that the required insurance coverage has been replaced or reinstated;

19.3.2 Engineer's Certifications - Every three (3) years after the Operation Date, Seller will supply Idaho Power with a Certification of Ongoing Operations and Maintenance (O&M) from a Registered Professional Engineer licensed in the State of Idaho, which Certification of Ongoing O & M shall be in the form specified in Appendix C. Seller's failure to supply the required certificate will be an event of default. Such a default may only be cured by Seller providing the required certificate; and

19.3.3 Licenses and Permits - During the full term of this Agreement, Seller shall maintain compliance with all permits and licenses described in paragraph 4.1.1 of this Agreement. In addition, Seller will supply Idaho Power with copies of any new or additional permits or licenses. At least every fifth Contract Year, Seller will update the documentation described in Paragraph 4.1.1. If at any time Seller fails to maintain compliance with the permits and licenses described in paragraph 4.1.1 or to provide the documentation required by this paragraph, such failure will be an event of default and may only be cured by Seller submitting to Idaho Power evidence of compliance from the permitting agency.

ARTICLE XX: GOVERNMENTAL AUTHORIZATION

20.1 This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party of this Agreement.

ARTICLE XXI: COMMISSION ORDER

21.1 This Agreement shall become finally effective upon the Commission's approval of all terms and provisions hereof without change or condition and declaration that all payments to be made to Seller hereunder shall be allowed as prudently incurred expenses for ratemaking purposes.

ARTICLE XXII: SUCCESSORS AND ASSIGNS

22.1 This Agreement and all of the terms and provisions hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties hereto, except that no assignment hereof by either Party shall become effective without the written consent of both Parties being first obtained. Such consent shall not be unreasonably withheld. Notwithstanding the foregoing, any party which Idaho Power may consolidate, or into which it may merge, or to which it may convey or transfer substantially all of its electric utility assets, shall automatically, without further act, and without need of consent or approval by the Seller, succeed to all of Idaho Power's rights, obligations and interests under this Agreement. This article shall not prevent a financing entity with recorded or secured rights from exercising all rights and remedies available to it under law or contract. Idaho Power shall have the right to be notified by the financing entity that it is exercising such rights or remedies.

ARTICLE XXIII: MODIFICATION

23.1 No modification to this Agreement shall be valid unless it is in writing and signed by both Parties and subsequently approved by the Commission.

ARTICLE XXIV: TAXES

24.1 Each Party shall pay before delinquency all taxes and other governmental charges which, if failed to be paid when due, could result in a lien upon the Facility or the Interconnection Facilities.

ARTICLE XXV: NOTICES

25.1 All written notices under this Agreement shall be directed as follows and shall be considered delivered when faxed, e-mailed and confirmed with deposit in the U.S. Mail, first-class, postage prepaid, as follows:

To Seller:

Original document to:

James Carkulis
802 W Bannock, ste 1200
Boise, ID 83702
E-mail: crudeen@exergydevelopment.com

To Idaho Power:

Original document to:

Senior Vice President, Power Supply
Idaho Power Company
P.O. Box 70
Boise, Idaho 83707
Email: Lgrow@idahopower.com

Copy of document to:

Cogeneration and Small Power Production
Idaho Power Company
P.O. Box 70
Boise, Idaho 83707
E-mail: rallphin@idahopower.com

Either Party may change the contact person and/or address information listed above, by providing written notice from an authorized person representing the Party.

ARTICLE XXVI: ADDITIONAL TERMS AND CONDITIONS

26.1 This Agreement includes the following appendices, which are attached hereto and included by reference:

Appendix A	-	Monthly Power Production and Availability Report
Appendix B	-	Facility and Point of Delivery
Appendix C	-	Engineer's Certifications
Appendix D	-	Forms of Liquid Security
Appendix E	-	Wind Energy Production Forecasting

ARTICLE XXVII: SEVERABILITY

27.1 The invalidity or unenforceability of any term or provision of this Agreement shall not affect the validity or enforceability of any other terms or provisions and this Agreement shall be construed

in all other respects as if the invalid or unenforceable term or provision were omitted.

ARTICLE XXVIII: COUNTERPARTS

28.1 This Agreement may be executed in two or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

ARTICLE XXIX: ENTIRE AGREEMENT

29.1 This Agreement constitutes the entire Agreement of the Parties concerning the subject matter hereof and supersedes all prior or contemporaneous oral or written agreements between the Parties concerning the subject matter hereof.

IN WITNESS WHEREOF, The Parties hereto have caused this Agreement to be executed in their respective names on the dates set forth below:

Idaho Power Company	Rogerson Flats Wind Park, LLC
By Lisa A. Grow	By
Lisa A. Grow Sr. Vice President, Power Supply	James Carkulis, Manager
Dated 12·10·10	Dated 09-December-2010
"Idaho Power"	"Seller"

APPENDIX A

A –1 MONTHLY POWER PRODUCTION AND AVAILABILITY REPORT

At the end of each month the following required documentation will be submitted to:

Idaho Power Company
Attn: Cogeneration and Small Power Production
P.O. Box 70
Boise, Idaho 83707

The meter readings required on this report will be the readings on the Idaho Power Meter Equipment measuring the Facility's total energy production delivered to Idaho Power and Station Usage and the maximum generated energy (kW) as recorded on the Metering Equipment and/or any other required energy measurements to adequately administer this Agreement. This document shall be the document to enable Idaho Power to begin the energy payment calculation and payment process. The meter readings on this report shall not be used to calculate the actual payment, but instead will be a check of the automated meter reading information that will be gathered as described in item A-2 below:

This report shall also include the Seller's calculation of the Mechanical Availability.

Idaho Power Company

Cogeneration and Small Power Production

MONTHLY POWER PRODUCTION AND AVAILABILITY REPORT

Month ____________ **Year** ____________

Project Name ______________________ **Project Number:** ____________

Address ______________________ **Phone Number:** ____________

City ________ **State** ____ **Zip** ________

	Net Facility Output	Station Usage	Station Usage	Metered Maximum Generation
Meter Number:				
End of Month kWh Meter Reading:				kW
Beginning of Month kWh Meter:				
Difference:				
Times Meter Constant:				Net Generation
kWh for the Month:	-	-	=	
Metered Demand:				

Mechanical Availability Guarantee

Seller Calculated Mechanical Availability ______________________

As specified in this Agreement, the Seller shall include with this monthly report a summary statement of the Mechanical Availability of this Facility for the calendar month. This summary shall include details as to how the Seller calculated this value and summary of the Facility data used in the calculation. Idaho Power and the Seller shall work together to mutually develop a summary report that provides the required data. Idaho Power reserves the right to review the detailed data used in this calculation as allowed within the Agreement.

______________________ ____________

Signature **Date**

A-2 AUTOMATED METER READING COLLECTION PROCESS

Monthly, Idaho Power will use the provided Metering and Telemetry equipment and processes to collect the meter reading information from the Idaho Power provided Metering Equipment that measures the Net Energy and energy delivered to supply Station Use for the Facility recorded at 12:00 AM (Midnight) of the last day of the month.

The meter information collected will include but not be limited to energy production, Station Use, the maximum generation (kW) and any other required energy measurements to adequately administer this Agreement.

A-3 ROUTINE REPORTING

Idaho Power Contact Information

Daily Energy Production Reporting

Call daily by 10 a.m., 1-800-356-4328 or 1-800-635-1093 and leave the following information:

- Project Identification - Project Name and Project Number
- Current Meter Reading
- Estimated Generation for the current day
- Estimated Generation for the next day

Planned and Unplanned Project outages

Call 1-800-345-1319 and leave the following information:

- Project Identification - Project Name and Project Number
- Approximate time outage occurred

Estimated day and time of project coming back online

Seller's Contact Information

24-Hour Project Operational Contact

Name: ____________________
Telephone Number: ____________________
Cell Phone: ____________________

Project On-site Contact information

Telephone Number: ______________________

APPENDIX B

FACILITY AND POINT OF DELIVERY

Project Name: Rogerson Flats Wind Park

Project Number: 31721300

B-1 DESCRIPTION OF FACILITY

(Must include the Nameplate Capacity rating and VAR capability (both leading and lagging) of all generation units to be included in the Facility.)

The facility will consist of thirteen 1.6 MW wind turbine generators, with a combined nameplate limited to 20 MW. VAR capability is .95 to .95 leading and lagging.

B-2 LOCATION OF FACILITY

Near: Rogerson, ID

T14S R15E

SEC 1: SE1/4SW1/4, SW/14SE1/4 SEC 12: W1/2, W1/2E12, W1/2SE1/3, NW1/4SE1/4

SEC 13: ALL SEC 7: SW1/4, SW1/4NW1/4, S1/2SE1/4, NW1/4SE1/4

County: Twin Falls, ID.

Description of Interconnection Location: N42° 12.74327, W114° 42.55795

Nearest Idaho Power Substation: ______________________________

B-3 SCHEDULED FIRST ENERGY AND OPERATION DATE

Seller has selected May 30, 2012 as the Scheduled First Energy Date.

Seller has selected June 30, 2012 as the Scheduled Operation Date.

In making these selections, Seller recognizes that adequate testing of the Facility and completion of all requirements in paragraph 5.2 of this Agreement must be completed prior to the project being granted an Operation Date.

B-4 MAXIMUM CAPACITY AMOUNT:

This value will be 20 MW which is consistent with the value provided by the Seller to Idaho Power in accordance with Schedule 72. This value is the maximum energy (MW) that potentially could be delivered by the Seller's Facility to the Idaho Power electrical system at any moment in time.

B-5 POINT OF DELIVERY

"Point of Delivery" means, unless otherwise agreed by both Parties, the point of where the Sellers Facility's energy is delivered to the Idaho Power electrical system. Schedule 72 will determine the specific Point of Delivery for this Facility. The Point of Delivery identified by Schedule 72 will become an integral part of this Agreement.

B-6 LOSSES

If the Idaho Power Metering equipment is capable of measuring the exact energy deliveries by the Seller to the Idaho Power electrical system at the Point of Delivery, no Losses will be calculated for this Facility. If the Idaho Power Metering equipment is unable to measure the exact energy deliveries by the Seller to the Idaho Power electrical system at the Point of Delivery, a Losses calculation will be established to measure the energy losses (kWh) between the Seller's Facility and the Idaho Power Point of Delivery. This loss calculation will be initially set at 2% of the kWh energy production recorded on the Facility generation metering equipment. At such time as Seller provides Idaho Power with the electrical equipment specifications (transformer loss specifications, conductor sizes, etc.) of all of the electrical equipment between the Facility and the Idaho Power electrical system, Idaho Power will configure a revised loss calculation formula to be agreed to by both parties and used to calculate the kWh Losses for the remaining term of the Agreement. If at any time during the term of this Agreement, Idaho Power determines that the loss calculation does not correctly reflect the actual kWh losses attributed to the electrical equipment between the Facility and the Idaho Power electrical system, Idaho Power may adjust the calculation and retroactively adjust the previous months kWh loss calculations.

B-7 METERING AND TELEMETRY

Schedule 72 will determine the specific metering and telemetry requirements for this Facility. At the minimum, the Metering Equipment and Telemetry equipment must be able to provide and record hourly energy deliveries to the Point of Delivery and any other energy measurements required to administer this Agreement. These specifications will include but not be limited to equipment specifications, equipment location, Idaho Power provided equipment, Seller provided equipment, and all costs associated with the equipment, design and installation of the Idaho Power provided equipment. Seller will arrange for and make available at Seller's cost communication circuit(s) compatible with Idaho Power's communications equipment and dedicated to Idaho Power's use terminating at the Idaho Power facilities capable of providing Idaho Power with continuous instantaneous information on the Facilities energy production. Idaho Power provided equipment will be owned and maintained by Idaho Power, with total cost of purchase, installation, operation, and maintenance, including administrative cost to be reimbursed to Idaho Power by the Seller. Payment of these costs will be in accordance with Schedule 72 and the total metering cost will be included in the calculation of the Monthly Operation and Maintenance Charges specified in Schedule 72.

B-8 NETWORK RESOURCE DESIGNATION

Idaho Power cannot accept or pay for generation from this Facility until a Network Resource Designation ("NRD") application has been accepted by Idaho Power's delivery business unit. Federal Energy Regulatory Commission ("FERC") rules require Idaho Power to prepare and submit the NRD. Because much of the information Idaho Power needs to prepare the NRD is specific to the Seller's Facility, Idaho Power's ability to file the NRD in a timely manner is contingent upon timely receipt of the required information from the Seller. Prior to Idaho Power beginning the process to enable Idaho Power to submit a request for NRD status for this Facility, the Seller shall have completed all requirements as specified in Paragraph 5.7 of this Agreement. **Seller's failure to provide complete and accurate information in a timely manner can**

significantly impact Idaho Power's ability and cost to attain the NRD designation for the Seller's Facility and the Seller shall bear the costs of any of these delays that are a result of any action or inaction by the Seller.

APPENDIX C

ENGINEER'S CERTIFICATION

OF

OPERATIONS & MAINTENANCE POLICY

The undersigned ______________________________, on behalf of himself/herself and __________, hereinafter collectively referred to as "Engineer," hereby states and certifies to the Seller as follows:

1. That Engineer is a Licensed Professional Engineer in good standing in the State of Idaho.

2. That Engineer has reviewed the Energy Sales Agreement, hereinafter "Agreement," between Idaho Power as Buyer, and ______________as Seller, dated ______________________.

3. That the cogeneration or small power production project which is the subject of the Agreement and this Statement is identified as IPCo Facility No. ______________ and is hereinafter referred to as the "Project."

4. That the Project, which is commonly known as the ________________Project, is located in Section _____ Township ________ Range _______, Boise Meridian, _________ County, Idaho.

5. That Engineer recognizes that the Agreement provides for the Project to furnish electrical energy to Idaho Power for a 20 year period.

6. That Engineer has substantial experience in the design, construction and operation of electric power plants of the same type as this Project.

7. That Engineer has no economic relationship to the Design Engineer of this Project.

8. That Engineer has reviewed and/or supervised the review of the Policy for Operation and Maintenance ("O&M") for this Project and it is his professional opinion that, provided said Project has been designed and built to appropriate standards, adherence to said O&M Policy will result in the Project's producing at or near the design electrical output, efficiency and plant factor for a 20 year period.

9. That Engineer recognizes that Idaho Power, in accordance with paragraph 5.2 of the Agreement, is relying on Engineer's representations and opinions contained in this Statement.

10. That Engineer certifies that the above statements are complete, true and accurate to the best of his/her knowledge and therefore sets his/her hand and seal below.

By ______________________________

(P.E. Stamp)

Date ______________________________

APPENDIX C

ENGINEER'S CERTIFICATION

OF

ONGOING OPERATIONS AND MAINTENANCE

The undersigned ______________________________, on behalf of himself/herself and ______________________ hereinafter collectively referred to as "Engineer," hereby states and certifies to the Seller as follows:

1. That Engineer is a Licensed Professional Engineer in good standing in the State of Idaho.

2. That Engineer has reviewed the Energy Sales Agreement, hereinafter "Agreement," between Idaho Power as Buyer, and ________________ as Seller, dated ______________________.

3. That the cogeneration or small power production project which is the subject of the Agreement and this Statement is identified as IPCo Facility No. ____________ and hereinafter referred to as the "Project".

4. That the Project, which is commonly known as the ________________ Project, is located in Section _____ Township ________ Range ________, Boise Meridian, __________ County, Idaho.

5. That Engineer recognizes that the Agreement provides for the Project to furnish electrical energy to Idaho Power for a 20 year period.

6. That Engineer has substantial experience in the design, construction and operation of electric power plants of the same type as this Project.

7. That Engineer has no economic relationship to the Design Engineer of this Project.

8. That Engineer has made a physical inspection of said Project, its operations and maintenance records since the last previous certified inspection. It is Engineer's professional opinion, based on the Project's appearance, that its ongoing O&M has been substantially in accordance with said O&M Policy; that it is in reasonably good operating condition; and that if adherence to said O&M Policy continues, the Project will continue producing at or near its design electrical output, efficiency and plant factor for the remaining ______ years of the Agreement.

9. That Engineer recognizes that Idaho Power, in accordance with paragraph 5.2 of the Agreement, is relying on Engineer's representations and opinions contained in this Statement.

10. That Engineer certifies that the above statements are complete, true and accurate to the best of his/her knowledge and therefore sets his/her hand and seal below.

By ______________________________

(P.E. Stamp)

Date ______________________________

APPENDIX C

ENGINEER'S CERTIFICATION

OF

DESIGN & CONSTRUCTION ADEQUACY

The undersigned ______________________________, on behalf of himself/herself and ______________________ hereinafter collectively referred to as "Engineer", hereby states and certifies to Idaho Power as follows:

1. That Engineer is a Licensed Professional Engineer in good standing in the State of Idaho.

2. That Engineer has reviewed the Firm Energy Sales Agreement, hereinafter "Agreement", between Idaho Power as Buyer, and ___________________________ as Seller, dated _________, ___________________________.

3. That the cogeneration or small power production project, which is the subject of the Agreement and this Statement, is identified as IPCo Facility No _______________ and is hereinafter referred to as the "Project".

4. That the Project, which is commonly known as the __________________ Project, is located in Section _____ Township ________ Range _______, Boise Meridian, __________ County, Idaho.

5. That Engineer recognizes that the Agreement provides for the Project to furnish electrical energy to Idaho Power for a 20 year period.

6. That Engineer has substantial experience in the design, construction and operation of electric power plants of the same type as this Project.

7. That Engineer has no economic relationship to the Design Engineer of this Project and has made the analysis of the plans and specifications independently.

8. That Engineer has reviewed the engineering design and construction of the Project, including the civil work, electrical work, generating equipment, prime mover conveyance system, Seller furnished Interconnection Facilities and other Project facilities and equipment.

9. That the Project has been constructed in accordance with said plans and specifications, all applicable codes and consistent with Prudent Electrical Practices as that term is described in the Agreement.

10. That the design and construction of the Project is such that with reasonable and prudent operation and maintenance practices by Seller, the Project is capable of performing in accordance with the terms of the Agreement and with Prudent Electrical Practices for a 20 year period.

11. That Engineer recognizes that Idaho Power, in accordance with paragraph 5.2 of the Agreement, in interconnecting the Project with its system, is relying on Engineer's representations and opinions contained in this Statement.

12. That Engineer certifies that the above statements are complete, true and accurate to the best of his/her knowledge and therefore sets his/her hand and seal below.

By ______________________________
(P.E. Stamp)

Date ______________________________

<u>APPENDIX D</u>

FORMS OF LIQUID SECURITY

The Seller shall provide Idaho Power with commercially reasonable security instruments such as Cash Escrow Security, Guarantee or Letter of Credit as those terms are defined below or other forms of liquid financial security that would provide readily available cash to Idaho Power to satisfy the Delay Security requirement and any other security requirement within this Agreement.

For the purpose of this Appendix D, the term "Credit Requirements" shall mean acceptable financial creditworthiness of the entity providing the security instrument in relation to the term of the obligation in the reasonable judgment of Idaho Power, provided that any guarantee and/or letter of credit issued by any other entity with a short-term or long-term investment grade credit rating by Standard & Poor's Corporation or Moody's Investor Services, Inc. shall be deemed to have acceptable financial creditworthiness.

1. Cash Escrow Security – Seller shall deposit funds in an escrow account established by the Seller in a banking institution acceptable to both Parties equal to the Delay Security or any other required security amount(s). The Seller shall be responsible for all costs, and receive any interest earned associated with establishing and maintaining the escrow account(s).

Guarantee or Letter of Credit Security – Seller shall post and maintain in an amount equal to the Delay Security or other required security amount(s): (a) a guaranty from a party that satisfies the Credit Requirements, in a form acceptable to Idaho Power at its discretion, or b) an irrevocable_Letter of Credit in a form acceptable to Idaho Power, in favor of Idaho Power. The Letter of Credit will be issued by a financial institution acceptable to both parties. The Seller shall be responsible for all costs associated with establishing and maintaining the Guarantee(s) or Letter(s) of Credit.

APPENDIX E

WIND ENERGY PRODUCTION FORECASTING

As specified in Commission Order 30488, Idaho Power shall make use of a Wind Energy Production Forecasting model to forecast the energy production from this Facility and other Qualifying Facility wind generation resources. Seller and Idaho Power will share the cost of Wind Energy Production Forecasting. The Facility's share of Wind Energy Production Forecasting is determined as specified below. Sellers share will not be greater than 0.1% of the total energy payments made to Seller by Idaho Power during the previous Contract Year.

a. For every month of this Agreement beginning with the first full month after the First Energy Date as specified in Appendix of this Agreement, the Wind Energy Production Forecasting Monthly Cost Allocation (MCA) will be due and payable by the Seller. Any Wind Energy Production Forecasting Monthly Cost Allocations (MCA) that are not reimbursed to Idaho Power shall be deducted from energy payments to the Seller.

   - As the value of the 0.1% cap of the Facilities total energy payments will not be known until the first Contract Year is complete, at the end of the first Contract Year any prior allocations that exceeded the 0.1% cap shall be adjusted to reflect the 0.1% cap and if the Facility has paid the monthly allocations a refund will be included in equal monthly amounts over the ensuing Contract Year. If the Facility has not paid the monthly allocations the amount due Idaho Power will be adjusted accordingly and the unpaid balance will be deducted from the ensuing Contract Year's energy payments.

b. During the first Contract Year, as the value of the 0.1% cap of the Facilities total

energy payments will not be known until the first Contract Year is complete, Idaho Power will deduct the Facility's calculated share of the Wind Energy Production Forecasting costs specified in item d each month during the first Contract Year and subsequently refund any overpayment (payments that exceed the cap) in equal monthly amounts over the ensuing Contract Year.

c. The cost allocation formula described below will be reviewed and revised if necessary on the last day of any month in which the cumulative MW nameplate of wind projects having Commission approved agreements to deliver energy to Idaho Power has been revised by an action of the Commission.

d. The monthly cost allocation will be based upon the following formula :

Where: <u>**Total MW (TMW)**</u> is equal to the total nameplate rating of all QF wind projects that are under contract to provide energy to Idaho Power Company.

<u>**Facility MW (FMW)**</u> is equal to the nameplate rating of this Facility as specified in Appendix B.

<u>**Annual Wind Energy Production Forecasting Cost (AFCost)**</u> is equal to the total annual cost Idaho Power incurs to provide Wind Energy Production Forecasting. Idaho Power will estimate the AFCost for the current year based upon the previous year's cost and expected costs for the current year. At year-end, Idaho Power will compare the actual costs to the estimated costs and any differences between the estimated AFCost and the actual AFCost will be included in the next year's AFCost.

Annual Cost Allocation (ACA) = AFCost X (FMW / TMW)

And

Monthly Cost Allocation (MCA) = ACA / 12

e. The Wind Energy Production Forecasting Monthly Cost Allocation (MCA) is

due and payable to Idaho Power. The MCA will first be netted against any monthly energy payments owed to the Seller. If the netting of the MCA against the monthly energy payments results in a balance being due Idaho Power, the Facility shall pay this amount within 15 days of the date of the payment invoice.

FIRM ENERGY SALES AGREEMENT

BETWEEN

IDAHO POWER COMPANY

AND

SALMON CREEK WIND PARK, LLC

TABLE OF CONTENTS

12/7/2010

FIRM ENERGY SALES AGREEMENT
(10 aMW or Less)

Project Name: Salmon Creek Wind Park

Project Number: 31721400

THIS AGREEMENT, entered into on this 10th day of December, 2010 between SALMON CREEK WIND PARK, LLC (Seller), and IDAHO POWER COMPANY, an Idaho corporation (Idaho Power), hereinafter sometimes referred to collectively as "Parties" or individually as "Party."

WITNESSETH:

WHEREAS, Seller will design, construct, own, maintain and operate an electric generation facility; and

WHEREAS, Seller wishes to sell, and Idaho Power is willing to purchase, firm electric energy produced by the Seller's Facility.

THEREFORE, In consideration of the mutual covenants and agreements hereinafter set forth, the Parties agree as follows:

ARTICLE I: DEFINITIONS

As used in this Agreement and the appendices attached hereto, the following terms shall have the following meanings:

1.1 "Availability Shortfall Price" - The current month's Mid-Columbia Market Energy Cost minus the current month's All Hours Energy Price specified in paragraph 7.3 of this Agreement. If this calculation results in a value less than 15.00 Mills/kWh the result shall be 15.00 Mills/kWh.

1.2 "Business Days" - means any calendar day that is not a Saturday, a Sunday, or a NERC recognized holiday.

1.3 "Calculated Net Energy Amount" - A monthly estimate, prepared and documented after the fact by Seller, reviewed and accepted by the Buyer that is the calculated monthly maximum energy deliveries (measured in kWh) for each individual wind turbine, totaled for the Facility to determine the total energy that the Facility could have delivered to Idaho Power during that month based upon: (1) each wind turbine's Nameplate Capacity, (2) Sufficient Prime Mover available for use by each wind turbine during the month, (3) incidents of Force Majeure, (4) scheduled maintenance, or (5) incidents of Forced Outages less Losses and Station Use. If the duration of an event characterized as item 3, 4 or 5 above (measured on each individual occurrence and individual wind turbine) lasts for less than 15 minutes, then the event will not be considered in this calculation. The Seller shall collect and maintain actual data to support this calculation and shall keep this data for a minimum of 3 years.

1.4 "Commission" - The Idaho Public Utilities Commission.

1.5 "Contract Year" - The period commencing each calendar year on the same calendar date as the Operation Date and ending 364 days thereafter.

1.6 "Delay Liquidated Damages" – Damages payable to Idaho Power as calculated in paragraph 5.3, 5.4, 5.5 and 5.6.

1.7 "Delay Period" – All days past the Scheduled Operation Date until the Seller's Facility achieves the Operation Date.

1.8 "Delay Price" - The current month's Mid-Columbia Market Energy Cost minus the current month's All Hours Energy Price specified in paragraph 7.3 of this Agreement. If this calculation results in a value less than 0, the result of this calculation will be 0.

1.9 "Designated Dispatch Facility" - Idaho Power's Systems Operations Group, or any subsequent group designated by Idaho Power.

1.10 "Effective Date" – The date stated in the opening paragraph of this Firm Energy Sales Agreement representing the date upon which this Firm Energy Sales Agreement was fully executed by both Parties.

1.11 "Facility" - That electric generation facility described in Appendix B of this Agreement.

1.12 "First Energy Date" - The day commencing at 00:01 hours, Mountain Time, following the day that Seller has satisfied the requirements of Article IV and the Seller begins delivering energy to the Idaho Power electrical system at the Point of Delivery.

1.13 "Forced Outage" – a partial or total reduction of a) the Facility's capacity to produce and/or deliver Net Energy to the Point of Delivery, or b) Idaho Power's ability to accept Net Energy at the Point of Delivery for non-economic reasons, as a result of Idaho Power or Facility: 1) equipment failure which was **not** the result of negligence or lack of preventative maintenance, or 2) responding to a transmission provider curtailment order, or 3) unplanned preventative maintenance to repair equipment that left unrepaired, would result in failure of equipment prior to the planned maintenance period, or 4) planned maintenance or construction of the Facility or electrical lines required to serve this Facility. The Parties shall make commercially reasonable efforts to perform this unplanned preventative maintenance during periods of low wind availability.

1.14 "Heavy Load Hours" – The daily hours beginning at 7:00 am, ending at 11:00 pm Mountain Time, (16 hours) excluding all hours on all Sundays, New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

1.15 "Inadvertent Energy" – Electric energy Seller does not intend to generate. Inadvertent energy is more particularly described in paragraph 7.5 of this Agreement.

1.16 "Interconnection Facilities" - All equipment specified in Idaho Power's Schedule 72.

1.17 "Initial Capacity Determination" – The process by which Idaho Power confirms that under normal or average design conditions the Facility will generate at no more than 10 average MW per month and is therefore eligible to be paid the published rates in accordance with Commission Order No. 29632.

1.18 "Light Load Hours" – The daily hours beginning at 11:00 pm, ending at 7:00 am Mountain Time (8 hours), plus all other hours on all Sundays, New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

1.19 "Losses" – The loss of electrical energy expressed in kilowatt hours (kWh) occurring as a result of the transformation and transmission of energy between the Metering Point and the point the Facility's energy is delivered to the Idaho Power electrical system. The loss calculation formula will be as specified in Appendix B of this Agreement.

1.20 "Market Energy Reference Price" – Eighty-five percent (85%) of the Mid-Columbia Market Energy Cost.

1.21 "Material Breach" – A Default (paragraph 19.2.1) subject to paragraph 19.2.2.

1.22 "Maximum Capacity Amount" – The maximum capacity (MW) of the Facility will be as specified in Appendix B of this Agreement.

1.23 "Mechanical Availability" - The percentage amount calculated by Seller within 5 days after the end of each month of the Facility's monthly actual Net Energy divided by the Facility's Calculated Net Energy Amount for the applicable month. Any damages due as a result of the Seller falling short of the Mechanical Availability Guarantee for each month shall be determined in accordance with paragraph 6.4.4.

1.24 "Mechanical Availability Guarantee" shall be as defined in paragraph 6.4.

1.25 "Metering Equipment" - All equipment specified in Schedule 72, this Agreement and any additional equipment specified in Appendix B required to measure, record and telemeter bi-directional power flows from the Seller's Facility at the Metering Point.

1.26 "Metering Point" - The physical point at which the Metering Equipment is located that enables accurate measurement of the Test Energy and Net Energy deliveries to Idaho Power at the Point of Delivery for this Facility that provides all necessary data to administer this Agreement.

1.27 "Mid- Columbia Market Energy Cost" – The monthly weighted average of the daily on-peak and off-peak Dow Jones Mid-Columbia Index (Dow Jones Mid-C Index) prices for non-firm energy. If the Dow Jones Mid-Columbia Index price is discontinued by the reporting agency, both Parties will mutually agree upon a replacement index, which is similar to the Dow Jones Mid-Columbia

Index. The selected replacement index will be consistent with other similar agreements and a commonly used index by the electrical industry.

1.28 "Nameplate Capacity" –The full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovolt-amperes, kilowatts, volts or other appropriate units. Usually indicated on a nameplate attached to the individual machine or device.

1.29 "Net Energy" – All of the electric energy produced by the Facility, less Station Use, less Losses, expressed in kilowatt hours (kWh) delivered to Idaho Power at the Point of Delivery. Subject to the terms of this Agreement, Seller commits to deliver all Net Energy to Idaho Power at the Point of Delivery for the full term of the Agreement. Net Energy does not include Inadvertent Energy.

1.30 "Operation Date" – The day commencing at 00:01 hours, Mountain Time, following the day that all requirements of paragraph 5.2 have been completed.

1.31 "Point of Delivery" – The location specified in Appendix B, where Idaho Power's and the Seller's electrical facilities are interconnected and the energy from this Facility is delivered to the Idaho Power electrical system.

1.32 "Prudent Electrical Practices" – Those practices, methods and equipment that are commonly and ordinarily used in electrical engineering and operations to operate electric equipment lawfully, safely, dependably, efficiently and economically.

1.33 "Scheduled Operation Date" – The date specified in Appendix B when Seller anticipates achieving the Operation Date. It is expected that the Scheduled Operation Date provided by the Seller shall be a reasonable estimate of the date that the Seller anticipates that the Seller's Facility shall achieve the Operation Date.

1.34 "Schedule 72" – Idaho Power's Tariff No 101, Schedule 72 or its successor schedules as approved by the Commission. The Seller shall be responsible to pay all costs of interconnection and integration of this Facility into the Idaho Power electrical system as specified within Schedule 72 and this Agreement.

1.35 "Season" – The three periods identified in paragraph 6.2.1 of this Agreement.

1.36 "Special Facilities" - Additions or alterations of transmission and/or distribution lines and transformers as described in Schedule 72.

1.37 "Station Use" – Electric energy that is used to operate equipment that is auxiliary or otherwise related to the production of electricity by the Facility.

1.38 "Sufficient Prime Mover" means wind speed that is (1) equal to or greater than the generation unit's manufacturer-specified minimum levels required for the generation unit to produce energy, and (2) equal to or less than the generation unit's manufacturer-specified maximum levels at which the generation unit can safely produce energy.

1.39 "Surplus Energy" – All Net Energy produced by the Seller's Facility and delivered by the Facility to the Idaho Power electrical system prior to the Operation Date.

1.40 "Total Cost of the Facility" - The total cost of structures, equipment and appurtenances.

1.41 "Wind Energy Production Forecast" – A forecast of energy deliveries from this Facility provided by an Idaho Power administered wind forecasting model. The Facility shall be responsible for an allocated portion of the total costs of the forecasting model as specified in Appendix E.

ARTICLE II: NO RELIANCE ON IDAHO POWER

2.1 Seller Independent Investigation - Seller warrants and represents to Idaho Power that in entering into this Agreement and the undertaking by Seller of the obligations set forth herein, Seller has investigated and determined that it is capable of performing hereunder and has not relied upon the advice, experience or expertise of Idaho Power in connection with the transactions contemplated by this Agreement.

2.2 Seller Independent Experts - All professionals or experts including, but not limited to, engineers, attorneys, or accountants that Seller may have consulted or relied on in undertaking the transactions contemplated by this Agreement have been solely those of Seller.

ARTICLE III: WARRANTIES

3.1 No Warranty by Idaho Power - Any review, acceptance or failure to review Seller's design, specifications, equipment or facilities shall not be an endorsement or a confirmation by Idaho Power and Idaho Power makes no warranties, expressed or implied, regarding any aspect of Seller's design, specifications, equipment or facilities, including, but not limited to, safety, durability, reliability, strength, capacity, adequacy or economic feasibility.

3.2 Qualifying Facility Status - Seller warrants that the Facility is a "Qualifying Facility," as that term is used and defined in 18 CFR 292.201 et seq. After initial qualification, Seller will take such steps as may be required to maintain the Facility's Qualifying Facility status during the term of this Agreement and Seller's failure to maintain Qualifying Facility status will be a Material Breach of this Agreement. Idaho Power reserves the right to review the Facility's Qualifying Facility status and associated support and compliance documents at anytime during the term of this Agreement.

ARTICLE IV: CONDITIONS TO ACCEPTANCE OF ENERGY

4.1 Prior to the First Energy Date and as a condition of Idaho Power's acceptance of deliveries of energy from the Seller under this Agreement, Seller shall:

4.1.1 Submit proof to Idaho Power that all licenses, permits or approvals necessary for Seller's operations have been obtained from applicable federal, state or local authorities, including, but not limited to, evidence of compliance with Subpart B, 18 CFR 292.201 et seq. as a certified Qualifying Facility.

4.1.2 Opinion of Counsel - Submit to Idaho Power an Opinion Letter signed by an attorney admitted to practice and in good standing in the State of Idaho providing an opinion that Seller's licenses, permits and approvals as set forth in paragraph 4.1.1 above are legally and validly issued, are held in the name of the Seller and, based on a reasonable independent review, counsel is of the opinion that Seller is in substantial compliance with said permits as of the date of the Opinion Letter. The Opinion Letter will be in a form acceptable to Idaho Power and will acknowledge that the attorney rendering the opinion understands that Idaho Power is relying on said opinion. Idaho Power's acceptance of the form will not be unreasonably withheld. The Opinion Letter will be governed by and shall be interpreted in accordance with the legal opinion accord of the American Bar Association Section of Business Law (1991).

4.1.3 Initial Capacity Determination - Submit to Idaho Power such data as Idaho Power may reasonably require to perform the Initial Capacity Determination. Such data will include but not be limited to, Nameplate Capacity, equipment specifications, prime mover data, resource characteristics, normal and/or average operating design conditions and Station Use data. Upon receipt of this information, Idaho Power will review the provided data and if necessary, request additional data to complete the Initial Capacity Determination within a reasonable time.

4.1.3.1 If the Maximum Capacity specified in Appendix B of this Agreement and the cumulative manufacture Nameplate Capacity rating of the individual generation units at this Facility is less than 10 MW, the Seller shall submit detailed, manufacturer, verifiable data of the Nameplate Capacity ratings of the actual individual generation units to be installed at this Facility. Upon verification by Idaho Power that the data provided establishes the combined Nameplate Capacity rating of the generation units to be installed at this Facility is less than 10 MW, it will be deemed that the Seller has satisfied the Initial Capacity Determination for this Facility.

4.1.4 Nameplate Capacity – Submit to Idaho Power manufacturer's and engineering documentation that establishes the Nameplate Capacity of each individual generation unit that is included within this entire Facility. Upon receipt of this data, Idaho Power shall review the provided data and determine if the Nameplate Capacity specified is reasonable based upon the manufacturer's specified generation ratings for the specific generation units.

4.1.5 Engineer's Certifications - Submit an executed Engineer's Certification of Design & Construction Adequacy and an Engineer's Certification of Operations and Maintenance (O&M) Policy as described in Commission Order No. 21690. These certificates will be in the form specified in Appendix C but may be modified to the extent necessary to recognize the different engineering disciplines providing the certificates.

4.1.6 Insurance - Submit written proof to Idaho Power of all insurance required in Article XIII.

4.1.7 Interconnection – Provide written confirmation from Idaho Power's delivery business unit that Seller has satisfied all interconnection requirements.

4.1.8 Network Resource Designation – The Seller's Facility has been designated as a network resource capable of delivering firm energy up to the amount of the Maximum Capacity.

4.1.8.1 Seller has provided all information required to enable Idaho Power to file an initial transmission capacity request.

a) Results of the initial transmission capacity request are known and acceptable to the Seller.

b) Seller acknowledges responsibility for all interconnection costs and any costs associated with acquiring adequate firm transmission capacity to enable the project to be classified as an Idaho Power designated firm network resource.

c.) If the Facility is located outside of the Idaho Power service territory, in addition to the above requirements, the Seller must provide evidence that the Seller has acquired firm transmission capacity from all required transmitting entities to deliver the Facility's energy to an acceptable point of delivery on the Idaho Power electrical system.

4.1.9 Written Acceptance – Request and obtain written confirmation from Idaho Power that all conditions to acceptance of energy have been fulfilled. Such written confirmation shall be provided within a commercially reasonable time following the Seller's request and will not be unreasonably withheld by Idaho Power.

ARTICLE V: TERM AND OPERATION DATE

5.1 Term - Subject to the provisions of paragraph 5.2 below, this Agreement shall become effective on the date first written and shall continue in full force and effect for a period of twenty (20) Contract Years from the Operation Date.

5.2 Operation Date - The Operation Date may occur only after the Facility has achieved all of the following:

a) Achieved the First Energy Date.

b) Commission approval of this Agreement in a form acceptable to Idaho Power has been received.

c) Seller has demonstrated to Idaho Power's satisfaction that the Facility is complete and able to provide energy in a consistent, reliable and safe manner.

d) Seller has requested an Operation Date from Idaho Power in a written format.

e) Seller has received written confirmation from Idaho Power of the Operation Date. This confirmation will not be unreasonably withheld by Idaho Power.

5.3 Operation Date Delay - Seller shall cause the Facility to achieve the Operation Date on or before the Scheduled Operation Date. Delays in the interconnection and transmission network upgrade study, design and construction process that **are not** Force Majeure events accepted by both Parties, **shall not** prevent Delay Liquidated Damages from being due and owing as calculated in accordance with this Agreement.

5.3.1 If the Operation Date occurs after the Scheduled Operation Date but on or prior to ninety (90) days following the Scheduled Operation Date, Seller shall pay Idaho Power Delay Liquidated Damages calculated at the end of each calendar month after the Scheduled Operation Date as follows:

Delay Liquidated Damages are equal to ((Current month's Initial Year Net Energy Amount as specified in paragraph 6.2.1 divided by the number of days in the current month) multiplied by the number of days in the Delay Period in the current month) multiplied by the current month's Delay Price.

5.3.2 If the Operation Date does not occur within ninety (90) days following the Scheduled Operation Date, the Seller shall pay Idaho Power Delay Liquidated Damages, in addition to those provided in paragraph 5.3.1, calculated as follows:

Forty five dollars ($45) multiplied by the Maximum Capacity with the Maximum Capacity being measured in kW.

5.4 If Seller fails to achieve the Operation Date within ninety (90) days following the Scheduled Operation Date, such failure will be a Material Breach and Idaho Power may terminate this Agreement at any time until the Seller cures the Material Breach. Additional Delay Liquidated Damages beyond those calculated in 5.3.1 and 5.3.2 will be calculated and payable using the Delay Liquidated Damage calculation described in 5.3.1 above for all days exceeding 90 days past the Scheduled Operation Date until such time as the Seller cures this Material Breach or Idaho Power terminates this Agreement.

5.5 Seller shall pay Idaho Power any calculated Delay Liquidated Damages within seven (7) days of when Idaho Power calculates and presents any Delay Liquidated Damages billings to the Seller. Seller's failure to pay these damages within the specified time will be a Material Breach of this Agreement and Idaho Power shall draw funds from the Delay Security provided by the Seller in an amount equal to the calculated Delay Liquidated Damages.

5.6 The Parties agree that the damages Idaho Power would incur due to delay in the Facility achieving the Operation Date on or before the Scheduled Operation Date would be difficult or impossible to predict with certainty, and that the Delay Liquidated Damages are an appropriate approximation of such damages.

5.7 Prior to the Seller executing this Agreement, the Seller shall have agreed to and executed a Letter of Understanding with Idaho Power that contains at a minimum the following requirements:

a) Seller has filed for interconnection and is in compliance with all payments and requirements of the interconnection process.

b) Seller has provided all information required to enable Idaho Power to file an initial transmission capacity request.

5.8 Within thirty (30) days of the date of a final non-appealable Commission Order as specified in Article XXI approving this Agreement; Seller shall post liquid security ("Delay Security") in a form as described in Appendix D equal to or exceeding the amount calculated in paragraph 5.8.1. Failure to post this Delay Security in the time specified above will be a Material Breach of this Agreement and Idaho Power may terminate this Agreement.

5.8.1 <u>Delay Security</u> The greater of forty five ($45) multiplied by the Maximum Capacity with the Maximum Capacity being measured in kW or the sum of three month's estimated revenue. Where the estimated three months of revenue is the estimated revenue associated with the first three full months following the estimated Scheduled Operation Date, the estimated kWh of energy production as specified in paragraph 6.2.1 for those three months multiplied by the All Hours Energy Price specified in paragraph 7.3 for each of those three months.

5.8.1.1 In the event (a) Seller provides Idaho Power with certification that (1) a generation interconnection agreement specifying a schedule that will enable this Facility to achieve the Operation Date no later than the Scheduled Operation Date has been completed and the Seller has paid all required interconnection costs, or (2) a generation interconnection agreement is substantially complete and all material costs of interconnection have been identified and agreed upon and the Seller is in compliance with all terms and conditions of the generation interconnection agreement, the Delay Security calculated in accordance with paragraph 5.8.1 will be reduced by ten percent (10%).

5.8.1.2 If the Seller has received a reduction in the calculated Delay Security as specified in paragraph 5.8.1.1 and subsequently (1) at Seller's request, the generation interconnection agreement specified in paragraph 5.8.1.1 is revised and as a result the Facility will not achieve its Operation Date by the Scheduled Operation Date, or (2) if the Seller does not maintain compliance with the generation interconnection agreement, the full amount of the Delay Security as calculated in paragraph 5.8.1 will be subject to reinstatement and will be due and owing within five (5) business days from the date Idaho Power requests reinstatement. Failure to timely reinstate the Delay Security will be a Material Breach of this Agreement.

5.8.2 Idaho Power shall release any remaining security posted hereunder after all calculated Delay Liquidated Damages are paid in full to Idaho Power and the earlier of: 1) thirty (30) days after the Operation Date has been achieved, or 2) sixty (60) days after the Agreement has been terminated.

ARTICLE VI: PURCHASE AND SALE OF NET ENERGY

6.1 Delivery and Acceptance of Net Energy - Except when either Party's performance is excused as provided herein, Idaho Power will purchase and Seller will sell all of the Net Energy to Idaho Power at the Point of Delivery. All Inadvertent Energy produced by the Facility will also be delivered by the Seller to Idaho Power at the Point of Delivery. At no time will the total amount of Net Energy and/or Inadvertent Energy produced by the Facility and delivered by the Seller to the Point of Delivery exceed the Maximum Capacity Amount.

6.2 Net Energy Amounts - Seller intends to produce and deliver Net Energy in the following monthly amounts. These amounts shall be consistent with the Mechanical Availability Guarantee.

6.2.1 Initial Year Monthly Net Energy Amounts:

	Month	kWh
Season 1	March	6,128,553
	April	5,679,690
	May	4,597,609
Season 2	July	3,696,361
	August	3,856,621
	November	5,585,873
	December	6,481,286
Season 3	June	3,903,920
	September	4,001,235
	October	4,922,843
	January	6,302,592
	February	6,416,221

6.3 Unless excused by an event of Force Majeure, Seller's failure to deliver Net Energy in any Contract Year in an amount equal to at least ten percent (10%) of the sum of the Initial Year Monthly Net Energy Amounts as specified in paragraph 6.2 shall constitute an event of default.

6.4 Mechanical Availability Guarantee – After the Operational Date has been established, the Facility shall achieve a minimum monthly Mechanical Availability of 85% for the Facility for each month during the full term of this Agreement (the "Mechanical Availability Guarantee"). Failure to achieve the Mechanical Availability Guarantee shall result in Idaho Power calculating damages as specified in paragraph 6.4.4.

6.4.1 At the same time the Seller provides the Monthly Power Production and Availability Report (Appendix A), the Seller shall provide and certify the calculation of the Facility's current month's Mechanical Availability. The Seller shall include a summary of all information used to calculate the Calculated Net Energy Amount including but not limited to: (a) Forced Outages, (b) Force Majeure events, (c) wind speeds and the impact on generation output, and (c) scheduled maintenance and Station Use information.

6.4.2 The Seller shall maintain and retain for three years detailed documentation supporting the monthly calculation of the Facility's Mechanical Availability.

6.4.3 Idaho Power shall have the right to review and audit the documentation supporting the calculation of the Facility's Mechanical Availability at reasonable times at the Seller's offices.

6.4.4 If the current month's Mechanical Availability is less than the Mechanical Availability Guarantee, damages shall be equal to:

> ((eighty-five (85) percent of the month's Calculated Net Energy Amount) minus the month's actual Net Energy deliveries) multiplied by the Availability Shortfall Price.

6.4.5 Any damages calculated in paragraph 6.4.4 will be offset against the current month's energy payment. If an unpaid balance remains after the damages are offset against the energy payment, the Seller shall pay in full the remaining balance within thirty (30) days of the date of the invoice.

ARTICLE VII: PURCHASE PRICE AND METHOD OF PAYMENT

7.1 Heavy Load Purchase Price – For all Net Energy received during Heavy Load Hours, Idaho Power will pay the non-levelized energy price in accordance with Commission Order 31025 adjusted in accordance with Commission Order 30415 for Heavy Load Hour Energy deliveries, adjusted in accordance with Commission Order 30488 for the wind integration charge, and with seasonalization factors applied:

	Season 1 - (73.50 %)	Season 2 - (120.00 %)	Season 3 - (100.00 %)
Year	Mills/kWh	Mills/kWh	Mills/kWh
2010	40.52	66.15	55.12
2011	42.80	69.87	58.24
2012	45.32	74.00	61.66
2013	47.71	78.18	64.92
2014	50.29	82.74	68.42
2015	53.05	87.64	72.17
2016	54.64	90.46	74.34
2017	56.20	93.23	76.61
2018	57.90	96.25	79.12
2019	59.57	99.21	81.59

2020	61.29	102.27	84.14
2021	63.33	105.90	87.16
2022	65.46	109.67	90.31
2023	67.67	113.59	93.57
2024	69.97	117.66	96.97
2025	72.35	121.90	100.50
2026	74.38	125.49	103.49
2027	76.62	129.20	106.58
2028	78.96	133.03	109.77
2029	81.38	136.97	113.06
2030	83.87	141.04	116.45
2031	87.22	146.51	121.01
2032	90.15	151.30	125.00
2033	93.19	156.26	129.13

7.2 Light Load Purchase Price – For all Net Energy received during Light Load Hours, Idaho Power will pay the non-levelized energy price in accordance with Commission Order 31025 adjusted in accordance with Commission Order 30415 for Light Load Hour Energy deliveries, adjusted in accordance with Commission Order 30488 for the wind integration charge, and with seasonalization factors applied:

Year	Season 1 - (73.50 %) Mills/kWh	Season 2 - (120.00 %) Mills/kWh	Season 3 - (100.00 %) Mills/kWh
2010	35.59	58.11	48.42
2011	37.88	61.84	51.54
2012	40.40	65.95	54.96
2013	42.79	69.86	58.22
2014	45.37	74.06	61.72
2015	48.13	78.91	65.48
2016	49.72	81.73	67.64
2017	51.28	84.50	69.76
2018	52.97	87.51	72.07
2019	54.65	90.47	74.35
2020	56.37	93.53	76.86
2021	58.41	97.16	79.88
2022	60.54	100.93	83.03
2023	62.74	104.85	86.29
2024	65.04	108.92	89.69
2025	67.43	113.16	93.22
2026	69.45	116.76	96.21
2027	71.55	120.47	99.30

2028	73.70	124.29	102.49
2029	76.03	128.24	105.78
2030	78.52	132.31	109.17
2031	81.87	137.77	113.73
2032	84.80	142.56	117.72
2033	87.84	147.52	121.85

7.3 All Hours Energy Price – The price to be used in the calculation of the Surplus Energy Price and Delay Price shall be the non-levelized energy price in accordance with Commission Order 31025 adjusted in accordance with Commission Order 30488 for the wind integration charge, and with seasonalization factors applied:

Year	Season 1 - (73.50 %) Mills/kWh	Season 2 - (120.00 %) Mills/kWh	Season 3 - (100.00 %) Mills/kWh
2010	38.33	62.57	52.14
2011	40.61	66.30	55.26
2012	43.13	70.42	58.68
2013	45.52	74.33	61.93
2014	48.10	78.85	65.44
2015	50.86	83.75	69.19
2016	52.45	86.58	71.36
2017	54.01	89.35	73.48
2018	55.71	92.36	75.88
2019	57.37	95.32	78.35
2020	59.10	98.38	80.90
2021	61.14	102.01	83.92
2022	63.27	105.78	87.07
2023	65.48	109.70	90.33
2024	67.78	113.77	93.73
2025	70.16	118.01	97.26
2026	72.18	121.60	100.25
2027	74.28	125.31	103.35
2028	76.58	129.14	106.53
2029	79.00	133.09	109.82
2030	81.49	137.16	113.21
2031	84.84	142.62	117.77
2032	87.77	147.41	121.76
2033	90.81	152.37	125.89

7.4 Surplus Energy Price - For all Surplus Energy, Idaho Power shall pay to the Seller the current month's Market Energy Reference Price or the All Hours Energy Price specified in paragraph

7.3, whichever is lower.

7.5 Inadvertent Energy –

7.5.1 Inadvertent Energy is electric energy produced by the Facility, expressed in kWh, which the Seller delivers to Idaho Power at the Point of Delivery that exceeds 10,000 kW multiplied by the hours in the specific month in which the energy was delivered. (For example January contains 744 hours. 744 hours times 10,000 kW = 7,440,000 kWh. Energy delivered in January in excess of 7,440, 000 kWh in this example would be Inadvertent Energy.)

7.5.2 Although Seller intends to design and operate the Facility to generate no more than ten (10) average MW and therefore does not intend to generate Inadvertent Energy, Idaho Power will accept Inadvertent Energy that does not exceed the Maximum Capacity Amount but will not purchase or pay for Inadvertent Energy.

7.6 Payment Due Date – Undisputed Energy payments, less the Wind Energy Production Forecasting Monthly Cost Allocation (MCA) described in Appendix E and any other payments due Idaho Power, will be disbursed to the Seller within 30 days of the date which Idaho Power receives and accepts the documentation of the monthly Mechanical Available Guarantee and the Net Energy actually delivered to Idaho Power as specified in Appendix A.

7.7 Continuing Jurisdiction of the Commission . This Agreement is a special contract and, as such, the rates, terms and conditions contained in this Agreement will be construed in accordance with Idaho Power Company v. Idaho Public Utilities Commission and Afton Energy, Inc., 107 Idaho 781, 693 P.2d 427 (1984), Idaho Power Company v. Idaho Public Utilities Commission, 107 Idaho 1122, 695 P.2d 1 261 (1985), Afton Energy, Inc, v. Idaho Power Company, 111 Idaho 925, 729 P.2d 400 (1986), Section 210 of the Public Utility Regulatory Policies Act of 1978 and 18 CFR §292.303-308.

ARTICLE VIII: ENVIRONMENTAL ATTRIBUTES

8.1 Seller retains ownership under this Agreement of green tags and renewable energy certificates (RECs), or the equivalent environmental attributes, directly associated with the production of energy from the Seller's Facility sold to Idaho Power.

ARTICLE IX: FACILITY AND INTERCONNECTION

9.1 Design of Facility - Seller will design, construct, install, own, operate and maintain the Facility and any Seller-owned Interconnection Facilities so as to allow safe and reliable generation and delivery of Net Energy and Inadvertent Energy to the Idaho Power Point of Delivery for the full term of the Agreement.

9.2 Interconnection Facilities - Except as specifically provided for in this Agreement, the required Interconnection Facilities will be in accordance with Schedule 72, the Generation Interconnection Process and Appendix B. The Seller is responsible for all costs associated with this equipment as specified in Schedule 72 and the Generation Interconnection Process, including but not limited to initial costs incurred by Idaho Power for equipment costs, installation costs and ongoing monthly Idaho Power operations and maintenance expenses.

ARTICLE X: METERING AND TELEMETRY

10.1 Metering - Idaho Power shall, for the account of Seller, provide, install, and maintain Metering and Telemetry Equipment to be located at a mutually agreed upon location to record and measure power flows to Idaho Power in accordance with this Agreement and Schedule 72. The Metering Equipment will be at the location and the type required to measure, record and report the Facility's Net Energy, Station Use, Inadvertent Energy and maximum energy deliveries (kW) at the Point of Delivery in a manner to provide Idaho Power adequate energy measurement data to administer this Agreement and to integrate this Facility's energy production into the Idaho Power electrical system.

10.2 Telemetry – Idaho Power will install, operate and maintain at Seller's expense metering,

communications and telemetry equipment which will be capable of providing Idaho Power with continuous instantaneous telemetry of Seller's Net Energy and Inadvertent Energy produced and delivered to the Idaho Power Point of Delivery to Idaho Power's Designated Dispatch Facility.

ARTICLE XI - RECORDS

11.1 Maintenance of Records - Seller shall maintain at the Facility or such other location mutually acceptable to the Parties adequate total generation, Net Energy, Station Use, Inadvertent Energy and maximum generation (kW) records in a form and content acceptable to Idaho Power.

11.2 Inspection - Either Party, after reasonable notice to the other Party, shall have the right, during normal business hours, to inspect and audit any or all generation, Net Energy, Station Use, Inadvertent Energy and maximum generation (kW) records pertaining to the Seller's Facility.

ARTICLE XII: OPERATIONS

12 .1 Communications - Idaho Power and the Seller shall maintain appropriate operating communications through Idaho Power's Designated Dispatch Facility in accordance with Appendix A of this Agreement.

12 .2 Energy Acceptance –

12.2.1 Idaho Power shall be excused from accepting and paying for Net Energy or accepting Inadvertent Energy which would have otherwise been produced by the Facility and delivered by the Seller to the Point of Delivery, if it is prevented from doing so by an event of Force Majeure, Forced Outage or temporary disconnection of the Facility in accordance with Schedule 72. If, for reasons other than an event of Force Majeure or a Forced Outage, a temporary disconnection under Schedule 72 exceeds twenty (20) days, beginning with the twenty-first day of such interruption, curtailment or reduction, Seller will be deemed to be delivering Net Energy at a rate equivalent to the pro rata daily average of the amounts specified for the applicable month in paragraph 6.2. Idaho Power will notify Seller when the interruption, curtailment or reduction is terminated.

12.2.2 If, in the reasonable opinion of Idaho Power, Seller's operation of the Facility or Interconnection Facilities is unsafe or may otherwise adversely affect Idaho Power's equipment, personnel or service to its customers, Idaho Power may temporarily disconnect the Facility from Idaho Power's transmission/distribution system as specified within Schedule 72 or take such other reasonable steps as Idaho Power deems appropriate.

12.2.3 Under no circumstances will the Seller deliver Net Energy and/or Inadvertent Energy from the Facility to the Point of Delivery in an amount that exceeds the Maximum Capacity Amount at any moment in time. Seller's failure to limit deliveries to the Maximum Capacity Amount will be a Material Breach of this Agreement.

12.2.4 If Idaho Power is unable to accept the energy from this Facility and is not excused from accepting the Facility's energy, Idaho Power's damages shall be limited to only the value of the estimated energy that Idaho Power was unable to accept. Idaho Power will have no responsibility to pay for any other costs, lost revenue or consequential damages the Facility may incur.

12.3 Scheduled Maintenance – On or before January 31st of each calendar year, Seller shall submit a written proposed maintenance schedule of significant Facility maintenance for that calendar year and Idaho Power and Seller shall mutually agree as to the acceptability of the proposed schedule. The Parties determination as to the acceptability of the Seller's timetable for scheduled maintenance will take into consideration Prudent Electrical Practices, Idaho Power system requirements and the Seller's preferred schedule. Neither Party shall unreasonably withhold acceptance of the proposed maintenance schedule.

12.4 Maintenance Coordination - The Seller and Idaho Power shall, to the extent practical, coordinate their respective line and Facility maintenance schedules such that they occur simultaneously.

12.5 Contact Prior to Curtailment - Idaho Power will make a reasonable attempt to contact the Seller prior to exercising its rights to interrupt interconnection or curtail deliveries from the Seller's

Facility. Seller understands that in the case of emergency circumstances, real time operations of the electrical system, and/or unplanned events Idaho Power may not be able to provide notice to the Seller prior to interruption, curtailment, or reduction of electrical energy deliveries to Idaho Power.

ARTICLE XIII: INDEMNIFICATION AND INSURANCE

13.1 Indemnification - Each Party shall agree to hold harmless and to indemnify the other Party, its officers, agents, affiliates, subsidiaries, parent company and employees against all loss, damage, expense and liability to third persons for injury to or death of person or injury to property, proximately caused by the indemnifying Party's (a) construction, ownership, operation or maintenance of, or by failure of, any of such Party's works or facilities used in connection with this Agreement or (b) negligent or intentional acts, errors or omissions. The indemnifying Party shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity. The indemnifying Party shall pay all documented costs, including reasonable attorney fees that may be incurred by the other Party in enforcing this indemnity.

13.2 Insurance - During the term of this Agreement, Seller shall secure and continuously carry the following insurance coverage:

13.2.1 Comprehensive General Liability Insurance for both bodily injury and property damage with limits equal to $1,000,000, each occurrence, combined single limit. The deductible for such insurance shall be consistent with current Insurance Industry Utility practices for similar property.

13.2.2 The above insurance coverage shall be placed with an insurance company with an A.M. Best Company rating of A- or better and shall include:

(a) An endorsement naming Idaho Power as an additional insured and loss payee as applicable; and

(b) A provision stating that such policy shall not be canceled or the limits of liability reduced without sixty (60) days' prior written notice to Idaho Power.

13.3 Seller to Provide Certificate of Insurance - As required in paragraph 4.1.6 herein and annually thereafter, Seller shall furnish Idaho Power a certificate of insurance, together with the endorsements required therein, evidencing the coverage as set forth above.

13.4 Seller to Notify Idaho Power of Loss of Coverage - If the insurance coverage required by paragraph 13.2 shall lapse for any reason, Seller will immediately notify Idaho Power in writing. The notice will advise Idaho Power of the specific reason for the lapse and the steps Seller is taking to reinstate the coverage. Failure to provide this notice and to expeditiously reinstate or replace the coverage will constitute a Material Breach of this Agreement.

ARTICLE XIV: FORCE MAJEURE

14.1 As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the control of the Seller or of Idaho Power which, despite the exercise of due diligence, such Party is unable to prevent or overcome. Force Majeure includes, but is not limited to, acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, or changes in law or regulation occurring after the Effective Date, which, by the exercise of reasonable foresight such party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome. If either Party is rendered wholly or in part unable to perform its obligations under this Agreement because of an event of Force Majeure, both Parties shall be excused from whatever performance is affected by the event of Force Majeure, provided that:

(1) The non-performing Party shall, as soon as is reasonably possible after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence.

(2) The suspension of performance shall be of no greater scope and of no longer duration than is required by the event of Force Majeure.

(3) No obligations of either Party which arose before the occurrence causing the suspension of performance and which could and should have been fully

performed before such occurrence shall be excused as a result of such occurrence.

ARTICLE XV: LIABILITY; DEDICATION

15.1 Limitation of Liability. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. Neither party shall be liable to the other for any indirect, special, consequential, nor punitive damages, except as expressly authorized by this Agreement.

15.2 Dedication. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the Party or the public or affect the status of Idaho Power as an independent public utility corporation or Seller as an independent individual or entity.

ARTICLE XVI: SEVERAL OBLIGATIONS

16.1 Except where specifically stated in this Agreement to be otherwise, the duties, obligations and liabilities of the Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or impose a trust or partnership duty, obligation or liability on or with regard to either Party. Each Party shall be individually and severally liable for its own obligations under this Agreement.

ARTICLE XVII: WAIVER

17.1 Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent default or other matter.

ARTICLE XVIII: CHOICE OF LAWS AND VENUE

18.1 This Agreement shall be construed and interpreted in accordance with the laws of the State of Idaho without reference to its choice of law provisions.

18.2 Venue for any litigation arising out of or related to this Agreement will lie in the District Court of the Fourth Judicial District of Idaho in and for the County of Ada.

ARTICLE XIX: DISPUTES AND DEFAULT

19.1 Disputes - All disputes related to or arising under this Agreement, including, but not limited to, the interpretation of the terms and conditions of this Agreement, will be submitted to the Commission for resolution.

19.2 Notice of Default

19.2.1 Defaults. If either Party fails to perform any of the terms or conditions of this Agreement (an "event of default"), the non-defaulting Party shall cause notice in writing to be given to the defaulting Party, specifying the manner in which such default occurred. If the defaulting Party shall fail to cure such default within the sixty (60) days after service of such notice, or if the defaulting Party reasonably demonstrates to the other Party that the default can be cured within a commercially reasonable time but not within such sixty (60) day period and then fails to diligently pursue such cure, then, the non-defaulting Party may, at its option, terminate this Agreement and/or pursue its legal or equitable remedies.

19.2.2 Material Breaches – The notice and cure provisions in paragraph 19.2.1 do not apply to defaults identified in this Agreement as Material Breaches. Material Breaches must be cured as expeditiously as possible following occurrence of the breach.

19.3 Security for Performance - Prior to the Operation Date and thereafter for the full term of this Agreement, Seller will provide Idaho Power with the following:

19.3.1 Insurance - Evidence of compliance with the provisions of paragraph 13.2. If Seller

fails to comply, such failure will be a Material Breach and may only be cured by Seller supplying evidence that the required insurance coverage has been replaced or reinstated;

19.3.2 Engineer's Certifications - Every three (3) years after the Operation Date, Seller will supply Idaho Power with a Certification of Ongoing Operations and Maintenance (O&M) from a Registered Professional Engineer licensed in the State of Idaho, which Certification of Ongoing O & M shall be in the form specified in Appendix C. Seller's failure to supply the required certificate will be an event of default. Such a default may only be cured by Seller providing the required certificate; and

19.3.3 Licenses and Permits - During the full term of this Agreement, Seller shall maintain compliance with all permits and licenses described in paragraph 4.1.1 of this Agreement. In addition, Seller will supply Idaho Power with copies of any new or additional permits or licenses. At least every fifth Contract Year, Seller will update the documentation described in Paragraph 4.1.1. If at any time Seller fails to maintain compliance with the permits and licenses described in paragraph 4.1.1 or to provide the documentation required by this paragraph, such failure will be an event of default and may only be cured by Seller submitting to Idaho Power evidence of compliance from the permitting agency.

ARTICLE XX: GOVERNMENTAL AUTHORIZATION

20.1 This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party of this Agreement.

ARTICLE XXI: COMMISSION ORDER

21.1 This Agreement shall become finally effective upon the Commission's approval of all terms and provisions hereof without change or condition and declaration that all payments to be made to Seller hereunder shall be allowed as prudently incurred expenses for ratemaking purposes.

ARTICLE XXII: SUCCESSORS AND ASSIGNS

22.1 This Agreement and all of the terms and provisions hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties hereto, except that no assignment hereof by either Party shall become effective without the written consent of both Parties being first obtained. Such consent shall not be unreasonably withheld. Notwithstanding the foregoing, any party which Idaho Power may consolidate, or into which it may merge, or to which it may convey or transfer substantially all of its electric utility assets, shall automatically, without further act, and without need of consent or approval by the Seller, succeed to all of Idaho Power's rights, obligations and interests under this Agreement. This article shall not prevent a financing entity with recorded or secured rights from exercising all rights and remedies available to it under law or contract. Idaho Power shall have the right to be notified by the financing entity that it is exercising such rights or remedies.

ARTICLE XXIII: MODIFICATION

23.1 No modification to this Agreement shall be valid unless it is in writing and signed by both Parties and subsequently approved by the Commission.

ARTICLE XXIV: TAXES

24.1 Each Party shall pay before delinquency all taxes and other governmental charges which, if failed to be paid when due, could result in a lien upon the Facility or the Interconnection Facilities.

ARTICLE XXV: NOTICES

25.1 All written notices under this Agreement shall be directed as follows and shall be considered delivered when faxed, e-mailed and confirmed with deposit in the U.S. Mail, first-class, postage prepaid, as follows:

To Seller:

Original document to:

James Carkulis
802 W Bannock, ste 1200
Boise, ID 83702
E-mail: jcarkulis@exergydevelopment.com

To Idaho Power:

Original document to:

Senior Vice President, Power Supply
Idaho Power Company
P.O. Box 70
Boise, Idaho 83707
Email: Lgrow@idahopower.com

Copy of document to:

Cogeneration and Small Power Production
Idaho Power Company
P.O. Box 70
Boise, Idaho 83707
E-mail: rallphin@idahopower.com

Either Party may change the contact person and/or address information listed above, by providing written notice from an authorized person representing the Party.

ARTICLE XXVI: ADDITIONAL TERMS AND CONDITIONS

26.1 This Agreement includes the following appendices, which are attached hereto and included by reference:

Appendix A	-	Monthly Power Production and Availability Report
Appendix B	-	Facility and Point of Delivery
Appendix C	-	Engineer's Certifications
Appendix D	-	Forms of Liquid Security
Appendix E	-	Wind Energy Production Forecasting

ARTICLE XXVII: SEVERABILITY

27.1 The invalidity or unenforceability of any term or provision of this Agreement shall not affect the validity or enforceability of any other terms or provisions and this Agreement shall be construed

in all other respects as if the invalid or unenforceable term or provision were omitted.

ARTICLE XXVIII: COUNTERPARTS

28.1 This Agreement may be executed in two or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

ARTICLE XXIX: ENTIRE AGREEMENT

29.1 This Agreement constitutes the entire Agreement of the Parties concerning the subject matter hereof and supersedes all prior or contemporaneous oral or written agreements between the Parties concerning the subject matter hereof.

IN WITNESS WHEREOF, The Parties hereto have caused this Agreement to be executed in their respective names on the dates set forth below:

Idaho Power Company	Salmon Creek Wind Park, LLC
By Lisa A. Grow	By
Lisa A. Grow Sr. Vice President, Power Supply	James Carkulis, Manager
Dated 12·10·10	Dated 09-December-2010
"Idaho Power"	"Seller"

APPENDIX A

A – 1 MONTHLY POWER PRODUCTION AND AVAILABILITY REPORT

At the end of each month the following required documentation will be submitted to:

Idaho Power Company
Attn: Cogeneration and Small Power Production
P.O. Box 70
Boise, Idaho 83707

The meter readings required on this report will be the readings on the Idaho Power Meter Equipment measuring the Facility's total energy production delivered to Idaho Power and Station Usage and the maximum generated energy (kW) as recorded on the Metering Equipment and/or any other required energy measurements to adequately administer this Agreement. This document shall be the document to enable Idaho Power to begin the energy payment calculation and payment process. The meter readings on this report shall not be used to calculate the actual payment, but instead will be a check of the automated meter reading information that will be gathered as described in item A-2 below:

This report shall also include the Seller's calculation of the Mechanical Availability.

Idaho Power Company

Cogeneration and Small Power Production

MONTHLY POWER PRODUCTION AND AVAILABILITY REPORT

Month ______________ Year ______________

Project Name ______________ Project Number: ______________

Address ______________ Phone Number: ______________

City ______________ State ______ Zip ______________

	Net Facility Output	Station Usage	Station Usage	Metered Maximum Generation
Meter Number:				
End of Month kWh Meter Reading:				kW
Beginning of Month kWh Meter:				
Difference:				
Times Meter Constant:				Net Generation
kWh for the Month:	-	-	=	
Metered Demand:				

Mechanical Availability Guarantee

Seller Calculated Mechanical Availability ______________

As specified in this Agreement, the Seller shall include with this monthly report a summary statement of the Mechanical Availability of this Facility for the calendar month. This summary shall include details as to how the Seller calculated this value and summary of the Facility data used in the calculation. Idaho Power and the Seller shall work together to mutually develop a summary report that provides the required data. Idaho Power reserves the right to review the detailed data used in this calculation as allowed within the Agreement.

______________ Signature ______________ Date

A-2 AUTOMATED METER READING COLLECTION PROCESS

Monthly, Idaho Power will use the provided Metering and Telemetry equipment and processes to collect the meter reading information from the Idaho Power provided Metering Equipment that measures the Net Energy and energy delivered to supply Station Use for the Facility recorded at 12:00 AM (Midnight) of the last day of the month.

The meter information collected will include but not be limited to energy production, Station Use, the maximum generation (kW) and any other required energy measurements to adequately administer this Agreement.

A-3 ROUTINE REPORTING

Idaho Power Contact Information

Daily Energy Production Reporting

Call daily by 10 a.m., 1-800-356-4328 or 1-800-635-1093 and leave the following information:

- Project Identification - Project Name and Project Number
- Current Meter Reading
- Estimated Generation for the current day
- Estimated Generation for the next day

Planned and Unplanned Project outages

Call 1-800-345-1319 and leave the following information:

- Project Identification - Project Name and Project Number
- Approximate time outage occurred

Estimated day and time of project coming back online

Seller's Contact Information

24-Hour Project Operational Contact

Name: ________________
Telephone Number: ________________
Cell Phone: ________________

Project On-site Contact information

Telephone Number: ______________________

APPENDIX B

FACILITY AND POINT OF DELIVERY

Project Name: Salmon Creek Wind Park

Project Number: 31721400

B-1 DESCRIPTION OF FACILITY

(Must include the Nameplate Capacity rating and VAR capability (both leading and lagging) of all generation units to be included in the Facility.)

The facility will consist of thirteen 1.6 MW wind turbine generators, with a combined nameplate limited to 20 MW. VAR capability is .95 to .95 leading and lagging.

B-2 LOCATION OF FACILITY

Near: Rogerson, ID

T14S R15E

SEC 24: E1/2, E1/2W1/2 SEC 26: E1/2E1/2, SE1/4SW1/4, SW1/4SE1/4

County: Twin Falls, ID.

Description of Interconnection Location: N42° 10.66260', W114° 36.17400'

Nearest Idaho Power Substation: ______________________

B-3 SCHEDULED FIRST ENERGY AND OPERATION DATE

Seller has selected May 30, 2012 as the Scheduled First Energy Date.

Seller has selected June 30, 2012 as the Scheduled Operation Date.

In making these selections, Seller recognizes that adequate testing of the Facility and completion of all requirements in paragraph 5.2 of this Agreement must be completed prior to the project being granted an Operation Date.

B-4 MAXIMUM CAPACITY AMOUNT:

This value will be 20 MW which is consistent with the value provided by the Seller to Idaho Power in accordance with Schedule 72. This value is the maximum energy (MW) that potentially could be delivered by the Seller's Facility to the Idaho Power electrical system at any moment in time.

B-5 POINT OF DELIVERY

"Point of Delivery" means, unless otherwise agreed by both Parties, the point of where the Sellers Facility's energy is delivered to the Idaho Power electrical system. Schedule 72 will determine the specific Point of Delivery for this Facility. The Point of Delivery identified by Schedule 72 will become an integral part of this Agreement.

B-6 LOSSES

If the Idaho Power Metering equipment is capable of measuring the exact energy deliveries by the Seller to the Idaho Power electrical system at the Point of Delivery, no Losses will be calculated for this Facility. If the Idaho Power Metering equipment is unable to measure the exact energy deliveries by the Seller to the Idaho Power electrical system at the Point of Delivery, a Losses calculation will be established to measure the energy losses (kWh) between the Seller's Facility and the Idaho Power Point of Delivery. This loss calculation will be initially set at 2% of the kWh energy production recorded on the Facility generation metering equipment. At such time as Seller provides Idaho Power with the electrical equipment specifications (transformer loss specifications, conductor sizes, etc.) of all of the electrical equipment between the Facility and the Idaho Power electrical system, Idaho Power will configure a revised loss calculation formula to be agreed to by both parties and used to calculate the kWh Losses for the remaining term of the Agreement. If at any time during the term of this Agreement, Idaho Power determines that the loss calculation does not correctly reflect the actual kWh losses attributed to the electrical equipment between the Facility and the Idaho Power electrical system, Idaho Power may adjust the calculation and retroactively adjust the previous months kWh loss calculations.

B-7 METERING AND TELEMETRY

Schedule 72 will determine the specific metering and telemetry requirements for this Facility. At the minimum, the Metering Equipment and Telemetry equipment must be able to provide and record hourly energy deliveries to the Point of Delivery and any other energy measurements required to administer this Agreement. These specifications will include but not be limited to equipment specifications, equipment location, Idaho Power provided equipment, Seller provided equipment, and all costs associated with the equipment, design and installation of the Idaho Power provided equipment. Seller will arrange for and make available at Seller's cost communication circuit(s) compatible with Idaho Power's communications equipment and dedicated to Idaho Power's use terminating at the Idaho Power facilities capable of providing Idaho Power with continuous instantaneous information on the Facilities energy production. Idaho Power provided equipment will be owned and maintained by Idaho Power, with total cost of purchase, installation, operation, and maintenance, including administrative cost to be reimbursed to Idaho Power by the Seller. Payment of these costs will be in accordance with Schedule 72 and the total metering cost will be included in the calculation of the Monthly Operation and Maintenance Charges specified in Schedule 72.

B-8 NETWORK RESOURCE DESIGNATION

Idaho Power cannot accept or pay for generation from this Facility until a Network Resource Designation ("NRD") application has been accepted by Idaho Power's delivery business unit. Federal Energy Regulatory Commission ("FERC") rules require Idaho Power to prepare and submit the NRD. Because much of the information Idaho Power needs to prepare the NRD is specific to the Seller's Facility, Idaho Power's ability to file the NRD in a timely manner is contingent upon timely receipt of the required information from the Seller. Prior to Idaho Power beginning the process to enable Idaho Power to submit a request for NRD status for this Facility, the Seller shall have completed all requirements as specified in Paragraph 5.7 of this Agreement. **Seller's failure to provide complete and accurate information in a timely manner can**

significantly impact Idaho Power's ability and cost to attain the NRD designation for the Seller's Facility and the Seller shall bear the costs of any of these delays that are a result of any action or inaction by the Seller.

APPENDIX C

ENGINEER'S CERTIFICATION

OF

OPERATIONS & MAINTENANCE POLICY

The undersigned ______________________________, on behalf of himself/herself and __________, hereinafter collectively referred to as "Engineer," hereby states and certifies to the Seller as follows:

1. That Engineer is a Licensed Professional Engineer in good standing in the State of Idaho.

2. That Engineer has reviewed the Energy Sales Agreement, hereinafter "Agreement," between Idaho Power as Buyer, and ______________as Seller, dated ____________________.

3. That the cogeneration or small power production project which is the subject of the Agreement and this Statement is identified as IPCo Facility No. ______________ and is hereinafter referred to as the "Project."

4. That the Project, which is commonly known as the ________________Project, is located in Section _____ Township ________ Range ________, Boise Meridian, __________ County, Idaho.

5. That Engineer recognizes that the Agreement provides for the Project to furnish electrical energy to Idaho Power for a 20 year period.

6. That Engineer has substantial experience in the design, construction and operation of electric power plants of the same type as this Project.

7. That Engineer has no economic relationship to the Design Engineer of this Project.

8. That Engineer has reviewed and/or supervised the review of the Policy for Operation and Maintenance ("O&M") for this Project and it is his professional opinion that, provided said Project has been designed and built to appropriate standards, adherence to said O&M Policy will result in the Project's producing at or near the design electrical output, efficiency and plant factor for a 20 year period.

9. That Engineer recognizes that Idaho Power, in accordance with paragraph 5.2 of the Agreement, is relying on Engineer's representations and opinions contained in this Statement.

10. That Engineer certifies that the above statements are complete, true and accurate to the best of his/her knowledge and therefore sets his/her hand and seal below.

By ______________________________

(P.E. Stamp)

Date ______________________________

APPENDIX C

ENGINEER'S CERTIFICATION

OF

ONGOING OPERATIONS AND MAINTENANCE

The undersigned ______________________________, on behalf of himself/herself and ______________________ hereinafter collectively referred to as "Engineer," hereby states and certifies to the Seller as follows:

1. That Engineer is a Licensed Professional Engineer in good standing in the State of Idaho.

2. That Engineer has reviewed the Energy Sales Agreement, hereinafter "Agreement," between Idaho Power as Buyer, and ________________ as Seller, dated ______________________.

3. That the cogeneration or small power production project which is the subject of the Agreement and this Statement is identified as IPCo Facility No. ___________ and hereinafter referred to as the "Project".

4. That the Project, which is commonly known as the _________________Project, is located in Section _____ Township ________ Range _______, Boise Meridian, _________ County, Idaho.

5. That Engineer recognizes that the Agreement provides for the Project to furnish electrical energy to Idaho Power for a 20 year period.

6. That Engineer has substantial experience in the design, construction and operation of electric power plants of the same type as this Project.

7. That Engineer has no economic relationship to the Design Engineer of this Project.

8. That Engineer has made a physical inspection of said Project, its operations and maintenance records since the last previous certified inspection. It is Engineer's professional opinion, based on the Project's appearance, that its ongoing O&M has been substantially in accordance with said O&M Policy; that it is in reasonably good operating condition; and that if adherence to said O&M Policy continues, the Project will continue producing at or near its design electrical output, efficiency and plant factor for the remaining ______ years of the Agreement.

9. That Engineer recognizes that Idaho Power, in accordance with paragraph 5.2 of the Agreement, is relying on Engineer's representations and opinions contained in this Statement.

10. That Engineer certifies that the above statements are complete, true and accurate to the best of his/her knowledge and therefore sets his/her hand and seal below.

By ______________________________

(P.E. Stamp)

Date ______________________________

APPENDIX C

ENGINEER'S CERTIFICATION

OF

DESIGN & CONSTRUCTION ADEQUACY

The undersigned ______________________________, on behalf of himself/herself and ______________________ hereinafter collectively referred to as "Engineer", hereby states and certifies to Idaho Power as follows:

1. That Engineer is a Licensed Professional Engineer in good standing in the State of Idaho.

2. That Engineer has reviewed the Firm Energy Sales Agreement, hereinafter "Agreement", between Idaho Power as Buyer, and ________________________as Seller, dated ________, ________________________.

3. That the cogeneration or small power production project, which is the subject of the Agreement and this Statement, is identified as IPCo Facility No ______________ and is hereinafter referred to as the "Project".

4. That the Project, which is commonly known as the ________________Project, is located in Section _____ Township ________ Range ________, Boise Meridian, __________ County, Idaho.

5. That Engineer recognizes that the Agreement provides for the Project to furnish electrical energy to Idaho Power for a 20 year period.

6. That Engineer has substantial experience in the design, construction and operation of electric power plants of the same type as this Project.

7. That Engineer has no economic relationship to the Design Engineer of this Project and has made the analysis of the plans and specifications independently.

8. That Engineer has reviewed the engineering design and construction of the Project, including the civil work, electrical work, generating equipment, prime mover conveyance system, Seller furnished Interconnection Facilities and other Project facilities and equipment.

9. That the Project has been constructed in accordance with said plans and specifications, all applicable codes and consistent with Prudent Electrical Practices as that term is described in the Agreement.

10. That the design and construction of the Project is such that with reasonable and prudent operation and maintenance practices by Seller, the Project is capable of performing in accordance with the terms of the Agreement and with Prudent Electrical Practices for a 20 year period.

11. That Engineer recognizes that Idaho Power, in accordance with paragraph 5.2 of the Agreement, in interconnecting the Project with its system, is relying on Engineer's representations and opinions contained in this Statement.

12. That Engineer certifies that the above statements are complete, true and accurate to the best of his/her knowledge and therefore sets his/her hand and seal below.

By ______________________________

(P.E. Stamp)

Date ______________________________

<u>APPENDIX D</u>

FORMS OF LIQUID SECURITY

The Seller shall provide Idaho Power with commercially reasonable security instruments such as Cash Escrow Security, Guarantee or Letter of Credit as those terms are defined below or other forms of liquid financial security that would provide readily available cash to Idaho Power to satisfy the Delay Security requirement and any other security requirement within this Agreement.

For the purpose of this Appendix D, the term "Credit Requirements" shall mean acceptable financial creditworthiness of the entity providing the security instrument in relation to the term of the obligation in the reasonable judgment of Idaho Power, provided that any guarantee and/or letter of credit issued by any other entity with a short-term or long-term investment grade credit rating by Standard & Poor's Corporation or Moody's Investor Services, Inc. shall be deemed to have acceptable financial creditworthiness.

1. Cash Escrow Security – Seller shall deposit funds in an escrow account established by the Seller in a banking institution acceptable to both Parties equal to the Delay Security or any other required security amount(s). The Seller shall be responsible for all costs, and receive any interest earned associated with establishing and maintaining the escrow account(s).

Guarantee or Letter of Credit Security – Seller shall post and maintain in an amount equal to the Delay Security or other required security amount(s): (a) a guaranty from a party that satisfies the Credit Requirements, in a form acceptable to Idaho Power at its discretion, or b) an irrevocable_Letter of Credit in a form acceptable to Idaho Power, in favor of Idaho Power. The Letter of Credit will be issued by a financial institution acceptable to both parties. The Seller shall be responsible for all costs associated with establishing and maintaining the Guarantee(s) or Letter(s) of Credit.

APPENDIX E

WIND ENERGY PRODUCTION FORECASTING

As specified in Commission Order 30488, Idaho Power shall make use of a Wind Energy Production Forecasting model to forecast the energy production from this Facility and other Qualifying Facility wind generation resources. Seller and Idaho Power will share the cost of Wind Energy Production Forecasting. The Facility's share of Wind Energy Production Forecasting is determined as specified below. Sellers share will not be greater than 0.1% of the total energy payments made to Seller by Idaho Power during the previous Contract Year.

a. For every month of this Agreement beginning with the first full month after the First Energy Date as specified in Appendix of this Agreement, the Wind Energy Production Forecasting Monthly Cost Allocation (MCA) will be due and payable by the Seller. Any Wind Energy Production Forecasting Monthly Cost Allocations (MCA) that are not reimbursed to Idaho Power shall be deducted from energy payments to the Seller.

   - As the value of the 0.1% cap of the Facilities total energy payments will not be known until the first Contract Year is complete, at the end of the first Contract Year any prior allocations that exceeded the 0.1% cap shall be adjusted to reflect the 0.1% cap and if the Facility has paid the monthly allocations a refund will be included in equal monthly amounts over the ensuing Contract Year. If the Facility has not paid the monthly allocations the amount due Idaho Power will be adjusted accordingly and the unpaid balance will be deducted from the ensuing Contract Year's energy payments.

b. During the first Contract Year, as the value of the 0.1% cap of the Facilities total

energy payments will not be known until the first Contract Year is complete, Idaho Power will deduct the Facility's calculated share of the Wind Energy Production Forecasting costs specified in item d each month during the first Contract Year and subsequently refund any overpayment (payments that exceed the cap) in equal monthly amounts over the ensuing Contract Year.

c. The cost allocation formula described below will be reviewed and revised if necessary on the last day of any month in which the cumulative MW nameplate of wind projects having Commission approved agreements to deliver energy to Idaho Power has been revised by an action of the Commission.

d. The monthly cost allocation will be based upon the following formula :

Where: **Total MW (TMW)** is equal to the total nameplate rating of all QF wind projects that are under contract to provide energy to Idaho Power Company.

Facility MW (FMW) is equal to the nameplate rating of this Facility as specified in Appendix B.

Annual Wind Energy Production Forecasting Cost (AFCost) is equal to the total annual cost Idaho Power incurs to provide Wind Energy Production Forecasting. Idaho Power will estimate the AFCost for the current year based upon the previous year's cost and expected costs for the current year. At year-end, Idaho Power will compare the actual costs to the estimated costs and any differences between the estimated AFCost and the actual AFCost will be included in the next year's AFCost.

Annual Cost Allocation (ACA) = AFCost X (FMW / TMW)

And

Monthly Cost Allocation (MCA) = ACA / 12

e. The Wind Energy Production Forecasting Monthly Cost Allocation (MCA) is

due and payable to Idaho Power. The MCA will first be netted against any monthly energy payments owed to the Seller. If the netting of the MCA against the monthly energy payments results in a balance being due Idaho Power, the Facility shall pay this amount within 15 days of the date of the payment invoice.

FIRM ENERGY SALES AGREEMENT

BETWEEN

IDAHO POWER COMPANY

AND

COTTONWOOD WIND PARK, LLC

TABLE OF CONTENTS

FIRM ENERGY SALES AGREEMENT
(10 aMW or Less)

Project Name: Cottonwood Wind Park

Project Number: 31721100

THIS AGREEMENT, entered into on this 10Th day of December, 2010 between COTTONWOOD WIND PARK, LLC (Seller), and IDAHO POWER COMPANY, an Idaho corporation (Idaho Power), hereinafter sometimes referred to collectively as "Parties" or individually as "Party."

WITNESSETH:

WHEREAS, Seller will design, construct, own, maintain and operate an electric generation facility; and

WHEREAS, Seller wishes to sell, and Idaho Power is willing to purchase, firm electric energy produced by the Seller's Facility.

THEREFORE, In consideration of the mutual covenants and agreements hereinafter set forth, the Parties agree as follows:

ARTICLE I: DEFINITIONS

As used in this Agreement and the appendices attached hereto, the following terms shall have the following meanings:

1.1 "Availability Shortfall Price" - The current month's Mid-Columbia Market Energy Cost minus the current month's All Hours Energy Price specified in paragraph 7.3 of this Agreement. If this calculation results in a value less than 15.00 Mills/kWh the result shall be 15.00 Mills/kWh.

1.2 "Business Days" - means any calendar day that is not a Saturday, a Sunday, or a NERC recognized holiday.

1.3 "Calculated Net Energy Amount" - A monthly estimate, prepared and documented after the fact by Seller, reviewed and accepted by the Buyer that is the calculated monthly maximum energy deliveries (measured in kWh) for each individual wind turbine, totaled for the Facility to determine the total energy that the Facility could have delivered to Idaho Power during that month based upon: (1) each wind turbine's Nameplate Capacity, (2) Sufficient Prime Mover available for use by each wind turbine during the month, (3) incidents of Force Majeure, (4) scheduled maintenance, or (5) incidents of Forced Outages less Losses and Station Use. If the duration of an event characterized as item 3, 4 or 5 above (measured on each individual occurrence and individual wind turbine) lasts for less than 15 minutes, then the event will not be considered in this calculation. The Seller shall collect and maintain actual data to support this calculation and shall keep this data for a minimum of 3 years.

1.4 "Commission" - The Idaho Public Utilities Commission.

1.5 "Contract Year" - The period commencing each calendar year on the same calendar date as the Operation Date and ending 364 days thereafter.

1.6 "Delay Liquidated Damages" – Damages payable to Idaho Power as calculated in paragraph 5.3, 5.4, 5.5 and 5.6.

1.7 "Delay Period" – All days past the Scheduled Operation Date until the Seller's Facility achieves the Operation Date.

1.8 "Delay Price" - The current month's Mid-Columbia Market Energy Cost minus the current month's All Hours Energy Price specified in paragraph 7.3 of this Agreement. If this calculation results in a value less than 0, the result of this calculation will be 0.

1.9 "Designated Dispatch Facility" - Idaho Power's Systems Operations Group, or any subsequent group designated by Idaho Power.

1.10 "Effective Date" – The date stated in the opening paragraph of this Firm Energy Sales Agreement representing the date upon which this Firm Energy Sales Agreement was fully executed by both Parties.

1.11 "Facility" - That electric generation facility described in Appendix B of this Agreement.

1.12 "First Energy Date" - The day commencing at 00:01 hours, Mountain Time, following the day that Seller has satisfied the requirements of Article IV and the Seller begins delivering energy to Idaho Power's system at the Point of Delivery.

1.13 "Forced Outage" – a partial or total reduction of a) the Facility's capacity to produce and/or deliver Net Energy to the Point of Delivery, or b) Idaho Power's ability to accept Net Energy at the Point of Delivery for non-economic reasons, as a result of Idaho Power or Facility: 1) equipment failure which was **not** the result of negligence or lack of preventative maintenance, or 2) responding to a transmission provider curtailment order, or 3) unplanned preventative maintenance to repair equipment that left unrepaired, would result in failure of equipment prior to the planned maintenance period, or 4) planned maintenance or construction of the Facility or electrical lines required to serve this Facility. The Parties shall make commercially reasonable efforts to perform this unplanned preventative maintenance during periods of low wind availability.

1.14 "Heavy Load Hours" – The daily hours beginning at 7:00 am, ending at 11:00 pm Mountain Time, (16 hours) excluding all hours on all Sundays, New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

1.15 "Inadvertent Energy" – Electric energy Seller does not intend to generate. Inadvertent energy is more particularly described in paragraph 7.5 of this Agreement.

1.16 "Interconnection Facilities" - All equipment specified in Idaho Power's Schedule 72.

1.17 "Initial Capacity Determination" – The process by which Idaho Power confirms that under normal or average design conditions the Facility will generate at no more than 10 average MW per month and is therefore eligible to be paid the published rates in accordance with Commission Order No. 29632.

1.18 "Light Load Hours" – The daily hours beginning at 11:00 pm, ending at 7:00 am Mountain Time (8 hours), plus all other hours on all Sundays, New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

1.19 "Losses" – The loss of electrical energy expressed in kilowatt hours (kWh) occurring as a result of the transformation and transmission of energy between the Metering Point and the point the Facility's energy is delivered to the Idaho Power electrical system. The loss calculation formula will be as specified in Appendix B of this Agreement.

1.20 "Market Energy Reference Price" – Eighty-five percent (85%) of the Mid-Columbia Market Energy Cost.

1.21 "Material Breach" – A Default (paragraph 19.2.1) subject to paragraph 19.2.2.

1.22 "Maximum Capacity Amount" – The maximum capacity (MW) of the Facility will be as specified in Appendix B of this Agreement.

1.23 "Mechanical Availability" - The percentage amount calculated by Seller within 5 days after the end of each month of the Facility's monthly actual Net Energy divided by the Facility's Calculated Net Energy Amount for the applicable month. Any damages due as a result of the Seller falling short of the Mechanical Availability Guarantee for each month shall be determined in accordance with paragraph 6.4.4.

1.24 "Mechanical Availability Guarantee" shall be as defined in paragraph 6.4.

1.25 "Metering Equipment" - All equipment specified in Schedule 72, this Agreement and any additional equipment specified in Appendix B required to measure, record and telemeter bi-directional power flows from the Seller's Facility at the Metering Point.

1.26 "Metering Point" - The physical point at which the Metering Equipment is located that enables accurate measurement of the Test Energy and Net Energy deliveries to Idaho Power at the Point of Delivery for this Facility that provides all necessary data to administer this Agreement.

1.27 "Mid- Columbia Market Energy Cost" – The monthly weighted average of the daily on-peak and off-peak Dow Jones Mid-Columbia Index (Dow Jones Mid-C Index) prices for non-firm energy.

If the Dow Jones Mid-Columbia Index price is discontinued by the reporting agency, both Parties will mutually agree upon a replacement index, which is similar to the Dow Jones Mid-Columbia Index. The selected replacement index will be consistent with other similar agreements and a commonly used index by the electrical industry.

1.28 "Nameplate Capacity" –The full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovolt-amperes, kilowatts, volts or other appropriate units. Usually indicated on a nameplate attached to the individual machine or device.

1.29 "Net Energy" – All of the electric energy produced by the Facility, less Station Use, less Losses, expressed in kilowatt hours (kWh) delivered to Idaho Power at the Point of Delivery. Subject to the terms of this Agreement, Seller commits to deliver all Net Energy to Idaho Power at the Point of Delivery for the full term of the Agreement. Net Energy does not include Inadvertent Energy.

1.30 "Operation Date" – The day commencing at 00:01 hours, Mountain Time, following the day that all requirements of paragraph 5.2 have been completed.

1.31 "Point of Delivery" – The location specified in Appendix B, where Idaho Power's and the Seller's electrical facilities are interconnected and the energy from this Facility is delivered to the Idaho Power electrical system.

1.32 "Prudent Electrical Practices" – Those practices, methods and equipment that are commonly and ordinarily used in electrical engineering and operations to operate electric equipment lawfully, safely, dependably, efficiently and economically.

1.33 "Scheduled Operation Date" – The date specified in Appendix B when Seller anticipates achieving the Operation Date. It is expected that the Scheduled Operation Date provided by the Seller shall be a reasonable estimate of the date that the Seller anticipates that the Seller's Facility shall achieve the Operation Date.

1.34 "Schedule 72" – Idaho Power's Tariff No 101, Schedule 72 or its successor schedules as approved by the Commission. The Seller shall be responsible to pay all costs of interconnection and integration of this Facility into the Idaho Power electrical system as specified within Schedule 72 and this Agreement.

1.35 "Season" – The three periods identified in paragraph 6.2.1 of this Agreement.

1.36 "Special Facilities" - Additions or alterations of transmission and/or distribution lines and transformers as described in Schedule 72.

1.37 "Station Use" – Electric energy that is used to operate equipment that is auxiliary or otherwise related to the production of electricity by the Facility.

1.38 "Sufficient Prime Mover" means wind speed that is (1) equal to or greater than the generation unit's manufacturer-specified minimum levels required for the generation unit to produce energy and (2) equal to or less than the generation unit's manufacturer-specified maximum levels at which the generation unit can safely produce energy.

1.39 "Surplus Energy" – All Net Energy produced by the Seller's Facility and delivered by the Facility to the Idaho Power electrical system prior to the Operation Date.

1.40 "Total Cost of the Facility" - The total cost of structures, equipment and appurtenances.

1.41 "Wind Energy Production Forecast" – A forecast of energy deliveries from this Facility provided by an Idaho Power administered wind forecasting model. The Facility shall be responsible for an allocated portion of the total costs of the forecasting model as specified in Appendix E.

ARTICLE II: NO RELIANCE ON IDAHO POWER

2.1 Seller Independent Investigation - Seller warrants and represents to Idaho Power that in entering into this Agreement and the undertaking by Seller of the obligations set forth herein, Seller has investigated and determined that it is capable of performing hereunder and has not relied upon the advice, experience or expertise of Idaho Power in connection with the transactions contemplated by this Agreement.

2.2 Seller Independent Experts - All professionals or experts including, but not limited to, engineers, attorneys or accountants, that Seller may have consulted or relied on in undertaking the transactions contemplated by this Agreement have been solely those of Seller.

ARTICLE III: WARRANTIES

3.1 No Warranty by Idaho Power - Any review, acceptance or failure to review Seller's design, specifications, equipment or facilities shall not be an endorsement or a confirmation by Idaho Power and Idaho Power makes no warranties, expressed or implied, regarding any aspect of Seller's design, specifications, equipment or facilities, including, but not limited to, safety, durability, reliability, strength, capacity, adequacy or economic feasibility.

3.2 Qualifying Facility Status - Seller warrants that the Facility is a "Qualifying Facility," as that term is used and defined in 18 CFR 292.201 et seq. After initial qualification, Seller will take such steps as may be required to maintain the Facility's Qualifying Facility status during the term of this Agreement and Seller's failure to maintain Qualifying Facility status will be a Material Breach of this Agreement. Idaho Power reserves the right to review the Facility's Qualifying Facility status and associated support and compliance documents at anytime during the term of this Agreement.

ARTICLE IV: CONDITIONS TO ACCEPTANCE OF ENERGY

4.1 Prior to the First Energy Date and as a condition of Idaho Power's acceptance of deliveries of energy from the Seller under this Agreement, Seller shall:

4.1.1 Submit proof to Idaho Power that all licenses, permits or approvals necessary for Seller's operations have been obtained from applicable federal, state or local authorities, including, but not limited to, evidence of compliance with Subpart B, 18 CFR 292.201 et seq. as a certified Qualifying Facility.

4.1.2 Opinion of Counsel - Submit to Idaho Power an Opinion Letter signed by an attorney admitted to practice and in good standing in the State of Idaho providing an opinion that

Seller's licenses, permits and approvals as set forth in paragraph 4.1.1 above are legally and validly issued, are held in the name of the Seller and, based on a reasonable independent review, counsel is of the opinion that Seller is in substantial compliance with said permits as of the date of the Opinion Letter. The Opinion Letter will be in a form acceptable to Idaho Power and will acknowledge that the attorney rendering the opinion understands that Idaho Power is relying on said opinion. Idaho Power's acceptance of the form will not be unreasonably withheld. The Opinion Letter will be governed by and shall be interpreted in accordance with the legal opinion accord of the American Bar Association Section of Business Law (1991).

4.1.3 Initial Capacity Determination - Submit to Idaho Power such data as Idaho Power may reasonably require to perform the Initial Capacity Determination. Such data will include but not be limited to, Nameplate Capacity, equipment specifications, prime mover data, resource characteristics, normal and/or average operating design conditions and Station Use data. Upon receipt of this information, Idaho Power will review the provided data and if necessary, request additional data to complete the Initial Capacity Determination within a reasonable time.

4.1.3.1 If the Maximum Capacity specified in Appendix B of this Agreement and the cumulative manufacture Nameplate Capacity rating of the individual generation units at this Facility is less than 10 MW. The Seller shall submit detailed, manufacturer, verifiable data of the Nameplate Capacity ratings of the actual individual generation units to be installed at this Facility. Upon verification by Idaho Power that the data provided establishes the combined Nameplate Capacity rating of the generation units to be installed at this Facility is less than 10 MW, it will be deemed that the Seller has satisfied the Initial Capacity Determination for this Facility.

4.1.4 Nameplate Capacity – Submit to Idaho Power manufacturer's and engineering documentation that establishes the Nameplate Capacity of each individual generation unit that is included within this entire Facility. Upon receipt of this data, Idaho Power shall review the provided data and determine if the Nameplate Capacity specified is reasonable based upon the manufacturer's specified generation ratings for the specific generation units.

4.1.5 Engineer's Certifications - Submit an executed Engineer's Certification of Design & Construction Adequacy and an Engineer's Certification of Operations and Maintenance (O&M) Policy as described in Commission Order No. 21690. These certificates will be in the form specified in Appendix C but may be modified to the extent necessary to recognize the different engineering disciplines providing the certificates.

4.1.6 Insurance - Submit written proof to Idaho Power of all insurance required in Article XIII.

4.1.7 Interconnection – Provide written confirmation from Idaho Power's delivery business unit that Seller has satisfied all interconnection requirements.

4.1.8 Network Resource Designation – The Seller's Facility has been designated as a network resource capable of delivering firm energy up to the amount of the Maximum Capacity.

4.1.8.1 Seller has provided all information required to enable Idaho Power to file an initial transmission capacity request.

a) Results of the initial transmission capacity request are known and acceptable to the Seller.

b) Seller acknowledges responsibility for all interconnection costs and any costs associated with acquiring adequate firm transmission capacity to enable the project to be classified as an Idaho Power designated firm network resource.

c.) If the Facility is located outside of the Idaho Power service territory, in addition to the above requirements, the Seller must provide evidence that the Seller has acquired firm transmission capacity from all required transmitting entities to deliver the Facility's energy to an acceptable point of delivery on the Idaho Power electrical system.

4.1.9 Written Acceptance – Request and obtain written confirmation from Idaho Power that all conditions to acceptance of energy have been fulfilled. Such written confirmation shall be provided within a commercially reasonable time following the Seller's request and will not be unreasonably withheld by Idaho Power.

ARTICLE V: TERM AND OPERATION DATE

5.1 Term - Subject to the provisions of paragraph 5.2 below, this Agreement shall become effective on the date first written and shall continue in full force and effect for a period of 20 Contract Years from the Operation Date.

5.2 Operation Date - The Operation Date may occur only after the Facility has achieved all of the following:

a) Achieved the First Energy Date.

b) Commission approval of this Agreement in a form acceptable to Idaho Power has been received.

c) Seller has demonstrated to Idaho Power's satisfaction that the Facility is complete and able to provide energy in a consistent, reliable and safe manner.

d) Seller has requested an Operation Date from Idaho Power in a written format.

e) Seller has received written confirmation from Idaho Power of the Operation Date. This confirmation will not be unreasonably withheld by Idaho Power.

5.3 Operation Date Delay - Seller shall cause the Facility to achieve the Operation Date on or before the Scheduled Operation Date. Delays in the interconnection and transmission network upgrade study, design and construction process that **are not** Force Majeure events accepted by both Parties, **shall not** prevent Delay Liquidated Damages from being due and owing as calculated in accordance with this Agreement.

5.3.1 If the Operation Date occurs after the Scheduled Operation Date but on or prior to 90 days following the Scheduled Operation Date, Seller shall pay Idaho Power Delay Liquidated Damages calculated at the end of each calendar month after the Scheduled Operation Date as follows:

Delay Liquidated Damages are equal to ((Current month's Initial Year Net Energy Amount as specified in paragraph 6.2.1 divided by the number of days in the current month) multiplied by the number of days in the Delay Period in the current month) multiplied by the current month's Delay Price.

5.3.2 If the Operation Date does not occur within ninety (90) days following the Scheduled Operation Date, the Seller shall pay Idaho Power Delay Liquidated Damages, in addition to those provided in paragraph 5.3.1, calculated as follows:

Forty five dollars ($45) multiplied by the Maximum Capacity with the Maximum Capacity being measured in kW.

5.4 If Seller fails to achieve the Operation Date within ninety (90) days following the Scheduled Operation Date, such failure will be a Material Breach and Idaho Power may terminate this Agreement at any time until the Seller cures the Material Breach. Additional Delay Liquidated Damages beyond those calculated in 5.3.1 and 5.3.2 will be calculated and payable using the Delay Liquidated Damage calculation described in 5.3.1 above for all days exceeding 90 days past the Scheduled Operation Date until such time as the Seller cures this Material Breach or Idaho Power terminates this Agreement.

5.5 Seller shall pay Idaho Power any calculated Delay Liquidated Damages within 7 days of when Idaho Power calculates and presents any Delay Liquidated Damages billings to the Seller. Seller's failure to pay these damages within the specified time will be a Material Breach of this Agreement and Idaho Power shall draw funds from the Delay Security provided by the Seller in an amount equal to the calculated Delay Liquidated Damages.

5.6 The Parties agree that the damages Idaho Power would incur due to delay in the Facility achieving the Operation Date on or before the Scheduled Operation Date would be difficult or impossible to predict with certainty, and that the Delay Liquidated Damages are an appropriate approximation of such damages.

5.7 Prior to the Seller executing this Agreement, the Seller shall have agreed to and executed a Letter of Understanding with Idaho Power that contains at minimum the following requirements:

a) Seller has filed for interconnection and is in compliance with all payments and requirements of the interconnection process

b) Seller has provided all information required to enable Idaho Power to file an initial transmission capacity request.

5.8 Within thirty (30) days of the date of a final non-appealable Commission Order as specified in Article XXI approving this Agreement; Seller shall post liquid security ("Delay Security") in a form as described in Appendix D equal to or exceeding the amount calculated in paragraph 5.8.1. Failure to post this Delay Security in the time specified above will be a Material Breach of this Agreement and Idaho Power may terminate this Agreement.

5.8.1 Delay Security The greater of forty five ($45) multiplied by the Maximum Capacity with the Maximum Capacity being measured in kW or the sum of three month's estimated revenue. Where the estimated three months of revenue is the estimated revenue associated with the first three full months following the estimated Scheduled Operation Date, the estimated kWh of energy production as specified in paragraph 6.2.1 for those three months multiplied by the All Hours Energy Price specified in paragraph 7.3 for each of those three months.

5.8.1.1 In the event (a) Seller provides Idaho Power with certification that (1) a generation interconnection agreement specifying a schedule that will enable this Facility to achieve the Operation Date no later than the Scheduled Operation Date has been completed and the Seller has paid all required interconnection costs or (2) a generation interconnection agreement is substantially complete and all material costs of interconnection have been identified and agreed upon and the Seller is in compliance with all terms and conditions of the generation interconnection agreement, the Delay Security calculated in accordance with paragraph 5.8.1 will be reduced by ten percent (10%).

5.8.1.2 If the Seller has received a reduction in the calculated Delay Security as specified in paragraph 5.8.1.1 and subsequently (1) at Seller's request, the generation interconnection agreement specified in paragraph 5.8.1.1 is revised and as a result the Facility will not achieve its Operation Date by the Scheduled Operation Date, or (2) if the Seller does not maintain compliance with the generation interconnection agreement, the full amount of the Delay Security as calculated in paragraph 5.8.1 will be subject to reinstatement and will be due and owing within 5 business days from the date Idaho Power requests reinstatement. Failure to timely reinstate the Delay Security will be a Material Breach of this Agreement.

5.8.2 Idaho Power shall release any remaining security posted hereunder after all calculated Delay Liquidated Damages are paid in full to Idaho Power and the earlier of: 1) 30 days after the Operation Date has been achieved, or 2) 60 days after the Agreement has been terminated.

ARTICLE VI: PURCHASE AND SALE OF NET ENERGY

6.1 Delivery and Acceptance of Net Energy - Except when either Party's performance is excused as provided herein, Idaho Power will purchase and Seller will sell all of the Net Energy to Idaho Power at the Point of Delivery. All Inadvertent Energy produced by the Facility will also be delivered by the Seller to Idaho Power at the Point of Delivery. At no time will the total amount of Net Energy and/or Inadvertent Energy produced by the Facility and delivered by the Seller to the Point of Delivery exceed the Maximum Capacity Amount.

6.2 Net Energy Amounts - Seller intends to produce and deliver Net Energy in the following monthly amounts. These amounts shall be consistent with the Mechanical Availability Guarantee.

6.2.1 Initial Year Monthly Net Energy Amounts:

	Month	kWh
Season 1	March	6,128,553
	April	5,679,690
	May	4,597,609
Season 2	July	3,696,361
	August	3,856,621
	November	5,585,873
	December	6,481,286
Season 3	June	3,903,920
	September	4,001,235
	October	4,922,843
	January	6,302,592
	February	6,416,221

6.3 Unless excused by an event of Force Majeure, Seller's failure to deliver Net Energy in any Contract Year in an amount equal to at least ten percent (10%) of the sum of the Initial Year Monthly Net Energy Amounts as specified in paragraph 6.2 shall constitute an event of default.

6.4 Mechanical Availability Guarantee – After the Operational Date has been established, the Facility shall achieve a minimum monthly Mechanical Availability of 85% for the Facility for each month during the full term of this Agreement (the "Mechanical Availability Guarantee"). Failure to achieve the Mechanical Availability Guarantee shall result in Idaho Power calculating damages as specified in paragraph 6.4.4.

6.4.1 At the same time the Seller provides the Monthly Power Production and Availability Report (Appendix A), the Seller shall provide and certify the calculation of the Facility's current month's Mechanical Availability. The Seller shall include a summary of all information used to calculate the Calculated Net Energy Amount including but not limited to: (a) Forced Outages, (b) Force Majeure events, (c) wind speeds and the impact on generation output, and (c) scheduled maintenance and Station Use information.

6.4.2 The Seller shall maintain and retain for three years detailed documentation supporting the monthly calculation of the Facility's Mechanical Availability.

6.4.3 Idaho Power shall have the right to review and audit the documentation supporting the calculation of the Facility's Mechanical Availability at reasonable times at the Seller's offices.

6.4.4 If the current month's Mechanical Availability is less than the Mechanical Availability Guarantee, damages shall be equal to:

((85 percent of the month's Calculated Net Energy Amount) minus the month's actual Net Energy deliveries) multiplied by the Availability Shortfall Price.

6.4.5 Any damages calculated in paragraph 6.4.4 will be offset against the current month's energy payment. If an unpaid balance remains after the damages are offset against the energy payment, the Seller shall pay in full the remaining balance within 30 days of the date of the invoice.

ARTICLE VII: PURCHASE PRICE AND METHOD OF PAYMENT

7.1 Heavy Load Purchase Price – For all Net Energy received during Heavy Load Hours, Idaho Power will pay the non-levelized energy price in accordance with Commission Order 31025 adjusted in accordance with Commission Order 30415 for Heavy Load Hour Energy deliveries, adjusted in accordance with Commission Order 30488 for the wind integration charge, and with seasonalization factors applied:

	Season 1 - (73.50 %)	Season 2 - (120.00 %)	Season 3 - (100.00 %)
Year	Mills/kWh	Mills/kWh	Mills/kWh
2010	40.52	66.15	55.12
2011	42.80	69.87	58.24
2012	45.32	74.00	61.66
2013	47.71	78.18	64.92
2014	50.29	82.74	68.42
2015	53.05	87.64	72.17
2016	54.64	90.46	74.34
2017	56.20	93.23	76.61
2018	57.90	96.25	79.12
2019	59.57	99.21	81.59

2020	61.29	102.27	84.14
2021	63.33	105.90	87.16
2022	65.46	109.67	90.31
2023	67.67	113.59	93.57
2024	69.97	117.66	96.97
2025	72.35	121.90	100.50
2026	74.38	125.49	103.49
2027	76.62	129.20	106.58
2028	78.96	133.03	109.77
2029	81.38	136.97	113.06
2030	83.87	141.04	116.45
2031	87.22	146.51	121.01
2032	90.15	151.30	125.00
2033	93.19	156.26	129.13

7.2 Light Load Purchase Price – For all Net Energy received during Light Load Hours, Idaho Power will pay the non-levelized energy price in accordance with Commission Order 31025 adjusted in accordance with Commission Order 30415 for Light Load Hour Energy deliveries, adjusted in accordance with Commission Order 30488 for the wind integration charge, and with seasonalization factors applied:

Year	Season 1 - (73.50 %) Mills/kWh	Season 2 - (120.00 %) Mills/kWh	Season 3 - (100.00 %) Mills/kWh
2010	35.59	58.11	48.42
2011	37.88	61.84	51.54
2012	40.40	65.95	54.96
2013	42.79	69.86	58.22
2014	45.37	74.06	61.72
2015	48.13	78.91	65.48
2016	49.72	81.73	67.64
2017	51.28	84.50	69.76
2018	52.97	87.51	72.07
2019	54.65	90.47	74.35
2020	56.37	93.53	76.86
2021	58.41	97.16	79.88
2022	60.54	100.93	83.03
2023	62.74	104.85	86.29
2024	65.04	108.92	89.69
2025	67.43	113.16	93.22
2026	69.45	116.76	96.21
2027	71.55	120.47	99.30

2028	73.70	124.29	102.49
2029	76.03	128.24	105.78
2030	78.52	132.31	109.17
2031	81.87	137.77	113.73
2032	84.80	142.56	117.72
2033	87.84	147.52	121.85

7.3 All Hours Energy Price – The price to be used in the calculation of the Surplus Energy Price and Delay Price shall be the non-levelized energy price in accordance with Commission Order 31025 adjusted in accordance with Commission Order 30488 for the wind integration charge, and with seasonalization factors applied:

Year	Season 1 - (73.50 %) Mills/kWh	Season 2 - (120.00 %) Mills/kWh	Season 3 - (100.00 %) Mills/kWh
2010	38.33	62.57	52.14
2011	40.61	66.30	55.26
2012	43.13	70.42	58.68
2013	45.52	74.33	61.93
2014	48.10	78.85	65.44
2015	50.86	83.75	69.19
2016	52.45	86.58	71.36
2017	54.01	89.35	73.48
2018	55.71	92.36	75.88
2019	57.37	95.32	78.35
2020	59.10	98.38	80.90
2021	61.14	102.01	83.92
2022	63.27	105.78	87.07
2023	65.48	109.70	90.33
2024	67.78	113.77	93.73
2025	70.16	118.01	97.26
2026	72.18	121.60	100.25
2027	74.28	125.31	103.35
2028	76.58	129.14	106.53
2029	79.00	133.09	109.82
2030	81.49	137.16	113.21
2031	84.84	142.62	117.77
2032	87.77	147.41	121.76
2033	90.81	152.37	125.89

7.4 Surplus Energy Price - For all Surplus Energy, Idaho Power shall pay to the Seller the current month's Market Energy Reference Price or the All Hours Energy Price specified in paragraph

7.3, whichever is lower.

7.5 Inadvertent Energy –

7.5.1 Inadvertent Energy is electric energy produced by the Facility, expressed in kWh, which the Seller delivers to Idaho Power at the Point of Delivery that exceeds 10,000 kW multiplied by the hours in the specific month in which the energy was delivered. (For example January contains 744 hours. 744 hours times 10,000 kW = 7,440,000 kWh. Energy delivered in January in excess of 7,440, 000 kWh in this example would be Inadvertent Energy.)

7.5.2 Although Seller intends to design and operate the Facility to generate no more than 10 average MW and therefore does not intend to generate Inadvertent Energy, Idaho Power will accept Inadvertent Energy that does not exceed the Maximum Capacity Amount but will not purchase or pay for Inadvertent Energy.

7.6 Payment Due Date – Undisputed Energy payments, less the Wind Energy Production Forecasting Monthly Cost Allocation (MCA) described in Appendix E and any other payments due Idaho Power, will be disbursed to the Seller within 30 days of the date which Idaho Power receives and accepts the documentation of the monthly Mechanical Available Guarantee and the Net Energy actually delivered to Idaho Power as specified in Appendix A.

7.7 Continuing Jurisdiction of the Commission This Agreement is a special contract and, as such, the rates, terms and conditions contained in this Agreement will be construed in accordance with Idaho Power Company v. Idaho Public Utilities Commission and Afton Energy, Inc., 107 Idaho 781, 693 P.2d 427 (1984), Idaho Power Company v. Idaho Public Utilities Commission, 107 Idaho 1122, 695 P.2d 1 261 (1985), Afton Energy, Inc. v. Idaho Power Company, 111 Idaho 925, 729 P.2d 400 (1986), Section 210 of the Public Utility Regulatory Policies Act of 1978 and 18 CFR §292.303-308.

ARTICLE VIII: ENVIRONMENTAL ATTRIBUTES

8.1 Seller retains ownership under this Agreement of Green Tags and Renewable Energy Certificates (RECs), or the equivalent environmental attributes, directly associated with the production of energy from the Seller's Facility sold to Idaho Power.

ARTICLE IX: FACILITY AND INTERCONNECTION

9.1 Design of Facility - Seller will design, construct, install, own, operate and maintain the Facility and any Seller-owned Interconnection Facilities so as to allow safe and reliable generation and delivery of Net Energy and Inadvertent Energy to the Idaho Power Point of Delivery for the full term of the Agreement.

9.2 Interconnection Facilities - Except as specifically provided for in this Agreement, the required Interconnection Facilities will be in accordance with Schedule 72, the Generation Interconnection Process and Appendix B. The Seller is responsible for all costs associated with this equipment as specified in Schedule 72 and the Generation Interconnection Process, including but not limited to initial costs incurred by Idaho Power for equipment costs, installation costs and ongoing monthly Idaho Power operations and maintenance expenses.

ARTICLE X: METERING AND TELEMETRY

10.1 Metering - Idaho Power shall, for the account of Seller, provide, install, and maintain Metering and Telemetry Equipment to be located at a mutually agreed upon location to record and measure power flows to Idaho Power in accordance with this Agreement and Schedule 72. The Metering Equipment will be at the location and the type required to measure, record and report the Facility's Net Energy, Station Use, Inadvertent Energy and maximum energy deliveries (kW) at the Point of Delivery in a manner to provide Idaho Power adequate energy measurement data to administer this Agreement and to integrate this Facility's energy production into the Idaho Power electrical system.

10.2 Telemetry – Idaho Power will install, operate and maintain at Seller's expense metering,

communications and telemetry equipment which will be capable of providing Idaho Power with continuous instantaneous telemetry of Seller's Net Energy and Inadvertent Energy produced and delivered to the Idaho Power Point of Delivery to Idaho Power's Designated Dispatch Facility.

ARTICLE XI - RECORDS

11.1 Maintenance of Records - Seller shall maintain at the Facility or such other location mutually acceptable to the Parties adequate total generation, Net Energy, Station Use, Inadvertent Energy and maximum generation (kW) records in a form and content acceptable to Idaho Power.

11.2 Inspection - Either Party, after reasonable notice to the other Party, shall have the right, during normal business hours, to inspect and audit any or all generation, Net Energy, Station Use, Inadvertent Energy and maximum generation (kW) records pertaining to the Seller's Facility.

ARTICLE XII: OPERATIONS

12 .1 Communications - Idaho Power and the Seller shall maintain appropriate operating communications through Idaho Power's Designated Dispatch Facility in accordance with Appendix A of this Agreement.

12 .2 Energy Acceptance –

12.2.1 Idaho Power shall be excused from accepting and paying for Net Energy or accepting Inadvertent Energy which would have otherwise been produced by the Facility and delivered by the Seller to the Point of Delivery, if it is prevented from doing so by an event of Force Majeure, Forced Outage or temporary disconnection of the Facility in accordance with Schedule 72. If, for reasons other than an event of Force Majeure or a Forced Outage, a temporary disconnection under Schedule 72 exceeds twenty (20) days, beginning with the twenty-first day of such interruption, curtailment or reduction, Seller will be deemed to be delivering Net Energy at a rate equivalent to the pro rata daily average of the amounts specified for the applicable month in paragraph 6.2. Idaho Power will notify Seller when the interruption, curtailment or reduction is terminated.

12.2.2 If, in the reasonable opinion of Idaho Power, Seller's operation of the Facility or Interconnection Facilities is unsafe or may otherwise adversely affect Idaho Power's equipment, personnel or service to its customers, Idaho Power may temporarily disconnect the Facility from Idaho Power's transmission/distribution system as specified within Schedule 72 or take such other reasonable steps as Idaho Power deems appropriate.

12.2.3 Under no circumstances will the Seller deliver Net Energy and/or Inadvertent Energy from the Facility to the Point of Delivery in an amount that exceeds the Maximum Capacity Amount at any moment in time. Seller's failure to limit deliveries to the Maximum Capacity Amount will be a Material Breach of this Agreement.

12.2.4 If Idaho Power is unable to accept the energy from this Facility and is not excused from accepting the Facility's energy, Idaho Power's damages shall be limited to only the value of the estimated energy that Idaho Power was unable to accept. Idaho Power will have no responsibility to pay for any other costs, lost revenue or consequential damages the Facility may incur.

12.3 Scheduled Maintenance – On or before January 31 of each calendar year, Seller shall submit a written proposed maintenance schedule of significant Facility maintenance for that calendar year and Idaho Power and Seller shall mutually agree as to the acceptability of the proposed schedule. The Parties determination as to the acceptability of the Seller's timetable for scheduled maintenance will take into consideration Prudent Electrical Practices, Idaho Power system requirements and the Seller's preferred schedule. Neither Party shall unreasonably withhold acceptance of the proposed maintenance schedule.

12.4 Maintenance Coordination - The Seller and Idaho Power shall, to the extent practical, coordinate their respective line and Facility maintenance schedules such that they occur simultaneously.

12.5 Contact Prior to Curtailment - Idaho Power will make a reasonable attempt to contact the Seller prior to exercising its rights to interrupt interconnection or curtail deliveries from the Seller's

Facility. Seller understands that in the case of emergency circumstances, real time operations of the electrical system, and/or unplanned events Idaho Power may not be able to provide notice to the Seller prior to interruption, curtailment, or reduction of electrical energy deliveries to Idaho Power.

ARTICLE XIII: INDEMNIFICATION AND INSURANCE

13.1 Indemnification - Each Party shall agree to hold harmless and to indemnify the other Party, its officers, agents, affiliates, subsidiaries, parent company and employees against all loss, damage, expense and liability to third persons for injury to or death of person or injury to property, proximately caused by the indemnifying Party's (a) construction, ownership, operation or maintenance of, or by failure of, any of such Party's works or facilities used in connection with this Agreement or (b) negligent or intentional acts, errors or omissions. The indemnifying Party shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity. The indemnifying Party shall pay all documented costs, including reasonable attorney fees that may be incurred by the other Party in enforcing this indemnity.

13.2 Insurance - During the term of this Agreement, Seller shall secure and continuously carry the following insurance coverage:

13.2.1 Comprehensive General Liability Insurance for both bodily injury and property damage with limits equal to $1,000,000, each occurrence, combined single limit. The deductible for such insurance shall be consistent with current Insurance Industry Utility practices for similar property.

13.2.2 The above insurance coverage shall be placed with an insurance company with an A.M. Best Company rating of A- or better and shall include:

(a) An endorsement naming Idaho Power as an additional insured and loss payee as applicable; and

(b) A provision stating that such policy shall not be canceled or the limits of liability reduced without sixty (60) days' prior written notice to Idaho Power.

13.3 Seller to Provide Certificate of Insurance - As required in paragraph 4.1.6 herein and annually thereafter, Seller shall furnish Idaho Power a certificate of insurance, together with the endorsements required therein, evidencing the coverage as set forth above.

13.4 Seller to Notify Idaho Power of Loss of Coverage - If the insurance coverage required by paragraph 13.2 shall lapse for any reason, Seller will immediately notify Idaho Power in writing. The notice will advise Idaho Power of the specific reason for the lapse and the steps Seller is taking to reinstate the coverage. Failure to provide this notice and to expeditiously reinstate or replace the coverage will constitute a Material Breach of this Agreement.

ARTICLE XIV: FORCE MAJEURE

14.1 As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the control of the Seller or of Idaho Power which, despite the exercise of due diligence, such Party is unable to prevent or overcome. Force Majeure includes, but is not limited to, acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, or changes in law or regulation occurring after the Effective Date, which, by the exercise of reasonable foresight such party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome. If either Party is rendered wholly or in part unable to perform its obligations under this Agreement because of an event of Force Majeure, both Parties shall be excused from whatever performance is affected by the event of Force Majeure, provided that:

(1) The non-performing Party shall, as soon as is reasonably possible after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence.

(2) The suspension of performance shall be of no greater scope and of no longer duration than is required by the event of Force Majeure.

(3) No obligations of either Party which arose before the occurrence causing the suspension of performance and which could and should have been fully

performed before such occurrence shall be excused as a result of such occurrence.

ARTICLE XV: LIABILITY; DEDICATION

15.1 Limitation of Liability. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. Neither party shall be liable to the other for any indirect, special, consequential, nor punitive damages, except as expressly authorized by this Agreement.

15.2 Dedication. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the Party or the public or affect the status of Idaho Power as an independent public utility corporation or Seller as an independent individual or entity.

ARTICLE XVI: SEVERAL OBLIGATIONS

16.1 Except where specifically stated in this Agreement to be otherwise, the duties, obligations and liabilities of the Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or impose a trust or partnership duty, obligation or liability on or with regard to either Party. Each Party shall be individually and severally liable for its own obligations under this Agreement.

ARTICLE XVII: WAIVER

17.1 Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent default or other matter.

ARTICLE XVIII: CHOICE OF LAWS AND VENUE

18.1 This Agreement shall be construed and interpreted in accordance with the laws of the State of Idaho without reference to its choice of law provisions.

18.2 Venue for any litigation arising out of or related to this Agreement will lie in the District Court of the Fourth Judicial District of Idaho in and for the County of Ada.

ARTICLE XIX: DISPUTES AND DEFAULT

19.1 Disputes - All disputes related to or arising under this Agreement, including, but not limited to, the interpretation of the terms and conditions of this Agreement, will be submitted to the Commission for resolution.

19.2 Notice of Default

19.2.1 Defaults. If either Party fails to perform any of the terms or conditions of this Agreement (an "event of default"), the non-defaulting Party shall cause notice in writing to be given to the defaulting Party, specifying the manner in which such default occurred. If the defaulting Party shall fail to cure such default within the sixty (60) days after service of such notice, or if the defaulting Party reasonably demonstrates to the other Party that the default can be cured within a commercially reasonable time but not within such sixty (60) day period and then fails to diligently pursue such cure, then, the non-defaulting Party may, at its option, terminate this Agreement and/or pursue its legal or equitable remedies.

19.2.2 Material Breaches – The notice and cure provisions in paragraph 19.2.1 do not apply to defaults identified in this Agreement as Material Breaches. Material Breaches must be cured as expeditiously as possible following occurrence of the breach.

19.3 Security for Performance - Prior to the Operation Date and thereafter for the full term of this Agreement, Seller will provide Idaho Power with the following:

19.3.1 Insurance - Evidence of compliance with the provisions of paragraph 13.2. If Seller

fails to comply, such failure will be a Material Breach and may only be cured by Seller supplying evidence that the required insurance coverage has been replaced or reinstated;

19.3.2 Engineer's Certifications - Every three (3) years after the Operation Date, Seller will supply Idaho Power with a Certification of Ongoing Operations and Maintenance (O&M) from a Registered Professional Engineer licensed in the State of Idaho, which Certification of Ongoing O & M shall be in the form specified in Appendix C. Seller's failure to supply the required certificate will be an event of default. Such a default may only be cured by Seller providing the required certificate; and

19.3.3 Licenses and Permits - During the full term of this Agreement, Seller shall maintain compliance with all permits and licenses described in paragraph 4.1.1 of this Agreement. In addition, Seller will supply Idaho Power with copies of any new or additional permits or licenses. At least every fifth Contract Year, Seller will update the documentation described in Paragraph 4.1.1. If at any time Seller fails to maintain compliance with the permits and licenses described in paragraph 4.1.1 or to provide the documentation required by this paragraph, such failure will be an event of default and may only be cured by Seller submitting to Idaho Power evidence of compliance from the permitting agency.

ARTICLE XX: GOVERNMENTAL AUTHORIZATION

20.1 This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party of this Agreement.

ARTICLE XXI: COMMISSION ORDER

21.1 This Agreement shall become finally effective upon the Commission's approval of all terms and provisions hereof without change or condition and declaration that all payments to be made to Seller hereunder shall be allowed as prudently incurred expenses for ratemaking purposes.

ARTICLE XXII: SUCCESSORS AND ASSIGNS

22.1 This Agreement and all of the terms and provisions hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties hereto, except that no assignment hereof by either Party shall become effective without the written consent of both Parties being first obtained. Such consent shall not be unreasonably withheld. Notwithstanding the foregoing, any party which Idaho Power may consolidate, or into which it may merge, or to which it may convey or transfer substantially all of its electric utility assets, shall automatically, without further act, and without need of consent or approval by the Seller, succeed to all of Idaho Power's rights, obligations and interests under this Agreement. This article shall not prevent a financing entity with recorded or secured rights from exercising all rights and remedies available to it under law or contract. Idaho Power shall have the right to be notified by the financing entity that it is exercising such rights or remedies.

ARTICLE XXIII: MODIFICATION

23.1 No modification to this Agreement shall be valid unless it is in writing and signed by both Parties and subsequently approved by the Commission.

ARTICLE XXIV: TAXES

24.1 Each Party shall pay before delinquency all taxes and other governmental charges which, if failed to be paid when due, could result in a lien upon the Facility or the Interconnection Facilities.

ARTICLE XXV: NOTICES

25.1 All written notices under this Agreement shall be directed as follows and shall be considered delivered when faxed, e-mailed and confirmed with deposit in the U.S. Mail, first-class, postage prepaid, as follows:

To Seller:

Original document to:

James Carkulis
802 W Bannock, ste 1200
Boise, ID 83702
E-mail: jcarkulis@exergydevelopment.com

To Idaho Power:

Original document to:

Vice President, Power Supply
Idaho Power Company
PO Box 70
Boise, Idaho 83707
Email: Lgrow@idahopower.com

Copy of document to:

Cogeneration and Small Power Production
Idaho Power Company
PO Box 70
Boise, Idaho 83707
E-mail: rallphin@idahopower.com

Either Party may change the contact person and/or address information listed above, by providing written notice from an authorized person representing the Party.

ARTICLE XXVI: ADDITIONAL TERMS AND CONDITIONS

26.1 This Agreement includes the following appendices, which are attached hereto and included by reference:

Appendix A	-	Monthly Power Production and Availability Report
Appendix B	-	Facility and Point of Delivery
Appendix C	-	Engineer's Certifications
Appendix D	-	Forms of Liquid Security
Appendix E	-	Wind Energy Production Forecasting

ARTICLE XXVII: SEVERABILITY

27.1 The invalidity or unenforceability of any term or provision of this Agreement shall not affect the validity or enforceability of any other terms or provisions and this Agreement shall be construed

in all other respects as if the invalid or unenforceable term or provision were omitted.

ARTICLE XXVIII: COUNTERPARTS

28.1 This Agreement may be executed in two or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

ARTICLE XXIX: ENTIRE AGREEMENT

29.1 This Agreement constitutes the entire Agreement of the Parties concerning the subject matter hereof and supersedes all prior or contemporaneous oral or written agreements between the Parties concerning the subject matter hereof.

IN WITNESS WHEREOF, The Parties hereto have caused this Agreement to be executed in their respective names on the dates set forth below:

Idaho Power Company	Cottonwood Wind Park, LLC
By Lisa A. Grow	By [signature]
Lisa A Grow Sr. Vice President, Power Supply	James Carkulis, Manager
Dated 12·10·10	Dated 09 - December · 2010
"Idaho Power"	"Seller"

APPENDIX A

A –1 MONTHLY POWER PRODUCTION AND AVAILABILITY REPORT

At the end of each month the following required documentation will be submitted to:

Idaho Power Company
Attn: Cogeneration and Small Power Production
PO Box 70
Boise, Idaho 83707

The meter readings required on this report will be the readings on the Idaho Power Meter Equipment measuring the Facility's total energy production delivered to Idaho Power and Station Usage and the maximum generated energy (kW) as recorded on the Metering Equipment and/or any other required energy measurements to adequately administer this Agreement. This document shall be the document to enable Idaho Power to begin the energy payment calculation and payment process. The meter readings on this report shall not be used to calculate the actual payment, but instead will be a check of the automated meter reading information that will be gathered as described in item A-2 below:

This report shall also include the Seller's calculation of the Mechanical Availability.

Idaho Power Company

Cogeneration and Small Power Production

MONTHLY POWER PRODUCTION AND AVAILABILITY REPORT

Month __________ Year __________

Project Name __________ Project Number: __________

Address __________ Phone Number: __________

City __________ State _____ Zip __________

	Net Facility Output		Station Usage		Station Usage		Metered Maximum Generation
Meter Number:							
End of Month kWh Meter Reading:							kW
Beginning of Month kWh Meter:							
Difference:							
Times Meter Constant:							**Net Generation**
kWh for the Month:		-		-		=	
Metered Demand:							

Mechanical Availability Guarantee

Seller Calculated Mechanical Availability __________

As specified in this Agreement, the Seller shall include with this monthly report a summary statement of the Mechanical Availability of this Facility for the calendar month. This summary shall include details as to how the Seller calculated this value and summary of the Facility data used in the calculation. Idaho Power and the Seller shall work together to mutually develop a summary report that provides the required data. Idaho Power reserves the right to review the detailed data used in this calculation as allowed within the Agreement.

____________________ __________

Signature Date

A-2 AUTOMATED METER READING COLLECTION PROCESS

Monthly, Idaho Power will use the provided Metering and Telemetry equipment and processes to collect the meter reading information from the Idaho Power provided Metering Equipment that measures the Net Energy and energy delivered to supply Station Use for the Facility recorded at 12:00 AM (Midnight) of the last day of the month..

The meter information collected will include but not be limited to energy production, Station Use, the maximum generated power (kW) and any other required energy measurements to adequately administer this Agreement.

A-3 ROUTINE REPORTING

Idaho Power Contact Information

Daily Energy Production Reporting

Call daily by 10 a.m., 1-800-356-4328 or 1-800-635-1093 and leave the following information:

- Project Identification - Project Name and Project Number
- Current Meter Reading
- Estimated Generation for the current day
- Estimated Generation for the next day

Planned and Unplanned Project outages

Call 1-800-345-1319 and leave the following information:

- Project Identification - Project Name and Project Number
- Approximate time outage occurred

Estimated day and time of project coming back online

Seller's Contact Information

24-Hour Project Operational Contact

Name: ____________________

Telephone Number: ____________________

Cell Phone: ____________________

Project On-site Contact information

Telephone Number: ______________________

APPENDIX B

FACILITY AND POINT OF DELIVERY

Project Name: Cottonwood Wind Park

Project Number: 31721100

B-1 DESCRIPTION OF FACILITY

(Must include the Nameplate Capacity rating and VAR capability (both leading and lagging) of all generation units to be included in the Facility.)

The facility will consist of thirteen 1.6 MW wind turbine generators, with a combined nameplate limited to 20 MW. VAR capability is .95 to .95 leading and lagging.

B-2 LOCATION OF FACILITY

Near: Rogerson, ID

T14S R15E

SEC 16: All SEC 21: E1/2, E1/2W1/2 SEC 28: NE1/4NW1/4, N1/2NE1/4

County: Twin Falls, ID.

Description of Interconnection Location: N42° 12.74327', W114° 42.55795

Nearest Idaho Power Substation: ____________________

B-3 SCHEDULED FIRST ENERGY AND OPERATION DATE

Seller has selected May 30, 2012 as the Scheduled First Energy Date.

Seller has selected June 30, 2012 as the Scheduled Operation Date.

In making these selections, Seller recognizes that adequate testing of the Facility and completion of all requirements in paragraph 5.2 of this Agreement must be completed prior to the project being granted an Operation Date.

B-4 MAXIMUM CAPACITY AMOUNT:

This value will be 20 MW which is consistent with the value provided by the Seller to Idaho Power in accordance with Schedule 72. This value is the maximum energy (MW) that potentially could be delivered by the Seller's Facility to the Idaho Power electrical system at any moment in time.

B-5 POINT OF DELIVERY

"Point of Delivery" means, unless otherwise agreed by both Parties, the point of where the Sellers Facility's energy is delivered to the Idaho Power electrical system. Schedule 72 will determine the specific Point of Delivery for this Facility. The Point of Delivery identified by Schedule 72 will become an integral part of this Agreement.

B-6 LOSSES

If the Idaho Power Metering equipment is capable of measuring the exact energy deliveries by the Seller to the Idaho Power electrical system at the Point of Delivery, no Losses will be calculated for this Facility. If the Idaho Power Metering equipment is unable to measure the exact energy deliveries by the Seller to the Idaho Power electrical system at the Point of Delivery, a Losses calculation will be established to measure the energy losses (kWh) between the Seller's Facility and the Idaho Power Point of Delivery. This loss calculation will be initially set at 2% of the kWh energy production recorded on the Facility generation metering equipment. At such time as Seller provides Idaho Power with the electrical equipment specifications (transformer loss specifications, conductor sizes, etc.) of all of the electrical equipment between the Facility and the Idaho Power electrical system, Idaho Power will configure a revised loss calculation formula to be agreed to by both parties and used to calculate the kWh Losses for the remaining term of the Agreement. If at any time during the term of this Agreement, Idaho Power determines that the loss calculation does not correctly reflect the actual kWh losses attributed to the electrical equipment between the Facility and the Idaho Power electrical system, Idaho Power may adjust the calculation and retroactively adjust the previous months kWh loss calculations.

B-7 METERING AND TELEMETRY

Schedule 72 will determine the specific metering and telemetry requirements for this Facility. At the minimum, the Metering Equipment and Telemetry equipment must be able to provide and record hourly energy deliveries to the Point of Delivery and any other energy measurements required to administer this Agreement. These specifications will include but not be limited to equipment specifications, equipment location, Idaho Power provided equipment, Seller provided equipment, and all costs associated with the equipment, design and installation of the Idaho Power provided equipment. Seller will arrange for and make available at Seller's cost communication circuit(s) compatible with Idaho Power's communications equipment and dedicated to Idaho Power's use terminating at the Idaho Power facilities capable of providing Idaho Power with continuous instantaneous information on the Facilities energy production. Idaho Power provided equipment will be owned and maintained by Idaho Power, with total cost of purchase, installation, operation, and maintenance, including administrative cost to be reimbursed to Idaho Power by the Seller. Payment of these costs will be in accordance with Schedule 72 and the total metering cost will be included in the calculation of the Monthly Operation and Maintenance Charges specified in Schedule 72.

B-8 NETWORK RESOURCE DESIGNATION

Idaho Power cannot accept or pay for generation from this Facility until a Network Resource Designation ("NRD") application has been accepted by Idaho Power's delivery business unit. Federal Energy Regulatory Commission ("FERC") rules require Idaho Power to prepare and submit the NRD. Because much of the information Idaho Power needs to prepare the NRD is specific to the Seller's Facility, Idaho Power's ability to file the NRD in a timely manner is contingent upon timely receipt of the required information from the Seller. Prior to Idaho Power beginning the process to enable Idaho Power to submit a request for NRD status for this Facility, the Seller shall have completed all requirements as specified in Paragraph 5.7 of this Agreement. **Seller's failure to provide complete and accurate information in a timely manner can**

significantly impact Idaho Power's ability and cost to attain the NRD designation for the Seller's Facility and the Seller shall bear the costs of any of these delays that are a result of any action or inaction by the Seller.

APPENDIX C

ENGINEER'S CERTIFICATION

OF

OPERATIONS & MAINTENANCE POLICY

The undersigned ______________________________, on behalf of himself/herself and __________, hereinafter collectively referred to as "Engineer," hereby states and certifies to the Seller as follows:

1. That Engineer is a Licensed Professional Engineer in good standing in the State of Idaho.

2. That Engineer has reviewed the Energy Sales Agreement, hereinafter "Agreement," between Idaho Power as Buyer, and ______________as Seller, dated ______________________.

3. That the cogeneration or small power production project which is the subject of the Agreement and this Statement is identified as IPCo Facility No. ______________ and is hereinafter referred to as the "Project."

4. That the Project, which is commonly known as the _________________Project, is located in Section _____ Township ________ Range _______, Boise Meridian, _________ County, Idaho.

5. That Engineer recognizes that the Agreement provides for the Project to furnish electrical energy to Idaho Power for a 20 year period.

6. That Engineer has substantial experience in the design, construction and operation of electric power plants of the same type as this Project.

7. That Engineer has no economic relationship to the Design Engineer of this Project.

8. That Engineer has reviewed and/or supervised the review of the Policy for Operation and Maintenance ("O&M") for this Project and it is his professional opinion that, provided said Project has been designed and built to appropriate standards, adherence to said O&M Policy will result in the Project's producing at or near the design electrical output, efficiency and plant factor for a 20 year period.

9. That Engineer recognizes that Idaho Power, in accordance with paragraph 5.2 of the Agreement, is relying on Engineer's representations and opinions contained in this Statement.

10. That Engineer certifies that the above statements are complete, true and accurate to the best of his/her knowledge and therefore sets his/her hand and seal below.

By ______________________________

(P.E. Stamp)

Date ______________________________

APPENDIX C

ENGINEER'S CERTIFICATION

OF

ONGOING OPERATIONS AND MAINTENANCE

The undersigned ______________________________, on behalf of himself/herself and ______________________ hereinafter collectively referred to as "Engineer," hereby states and certifies to the Seller as follows:

1. That Engineer is a Licensed Professional Engineer in good standing in the State of Idaho.

2. That Engineer has reviewed the Energy Sales Agreement, hereinafter "Agreement," between Idaho Power as Buyer, and _________________ as Seller, dated ______________________.

3. That the cogeneration or small power production project which is the subject of the Agreement and this Statement is identified as IPCo Facility No. ___________ and hereinafter referred to as the "Project".

4. That the Project, which is commonly known as the _______________ Project, is located in Section _____ Township ________ Range ________, Boise Meridian, __________ County, Idaho.

5. That Engineer recognizes that the Agreement provides for the Project to furnish electrical energy to Idaho Power for a 20 year period.

6. That Engineer has substantial experience in the design, construction and operation of electric power plants of the same type as this Project.

7. That Engineer has no economic relationship to the Design Engineer of this Project.

8. That Engineer has made a physical inspection of said Project, its operations and maintenance records since the last previous certified inspection. It is Engineer's professional opinion, based on the Project's appearance, that its ongoing O&M has been substantially in accordance with said O&M Policy; that it is in reasonably good operating condition; and that if adherence to said O&M Policy continues, the Project will continue producing at or near its design electrical output, efficiency and plant factor for the remaining ______ years of the Agreement.

9. That Engineer recognizes that Idaho Power, in accordance with paragraph 5.2 of the Agreement, is relying on Engineer's representations and opinions contained in this Statement.

10. That Engineer certifies that the above statements are complete, true and accurate to the best of his/her knowledge and therefore sets his/her hand and seal below.

By ______________________________

(P.E. Stamp)

Date ______________________________

APPENDIX C

ENGINEER'S CERTIFICATION

OF

DESIGN & CONSTRUCTION ADEQUACY

The undersigned ______________________, on behalf of himself/herself and ______________________ hereinafter collectively referred to as "Engineer", hereby states and certifies to Idaho Power as follows:

1. That Engineer is a Licensed Professional Engineer in good standing in the State of Idaho.

2. That Engineer has reviewed the Firm Energy Sales Agreement, hereinafter "Agreement", between Idaho Power as Buyer, and ______________________ as Seller, dated __________, ______________________.

3. That the cogeneration or small power production project, which is the subject of the Agreement and this Statement, is identified as IPCo Facility No ______________ and is hereinafter referred to as the "Project".

4. That the Project, which is commonly known as the ______________ Project, is located in Section _____ Township ________ Range ________, Boise Meridian, __________ County, Idaho.

5. That Engineer recognizes that the Agreement provides for the Project to furnish electrical energy to Idaho Power for a 20 year period.

6. That Engineer has substantial experience in the design, construction and operation of electric power plants of the same type as this Project.

7. That Engineer has no economic relationship to the Design Engineer of this Project and has made the analysis of the plans and specifications independently.

8. That Engineer has reviewed the engineering design and construction of the Project, including the civil work, electrical work, generating equipment, prime mover conveyance system, Seller furnished Interconnection Facilities and other Project facilities and equipment.

9. That the Project has been constructed in accordance with said plans and specifications, all applicable codes and consistent with Prudent Electrical Practices as that term is described in the Agreement.

10. That the design and construction of the Project is such that with reasonable and prudent operation and maintenance practices by Seller, the Project is capable of performing in accordance with the terms of the Agreement and with Prudent Electrical Practices for a 20 year period.

11. That Engineer recognizes that Idaho Power, in accordance with paragraph 5.2 of the Agreement, in interconnecting the Project with its system, is relying on Engineer's representations and opinions contained in this Statement.

12. That Engineer certifies that the above statements are complete, true and accurate to the best of his/her knowledge and therefore sets his/her hand and seal below.

By ______________________________
(P.E. Stamp)

Date ______________________________

APPENDIX D

FORMS OF LIQUID SECURITY

The Seller shall provide Idaho Power with commercially reasonable security instruments such as Cash Escrow Security, Guarantee or Letter of Credit as those terms are defined below or other forms of liquid financial security that would provide readily available cash to Idaho Power to satisfy the Delay Security requirement and any other security requirement within this Agreement.

For the purpose of this Appendix D, the term "Credit Requirements" shall mean acceptable financial creditworthiness of the entity providing the security instrument in relation to the term of the obligation in the reasonable judgment of Idaho Power, provided that any guarantee and/or letter of credit issued by any other entity with a short-term or long-term investment grade credit rating by Standard & Poor's Corporation or Moody's Investor Services, Inc. shall be deemed to have acceptable financial creditworthiness.

1. Cash Escrow Security – Seller shall deposit funds in an escrow account established by the Seller in a banking institution acceptable to both Parties equal to the Delay Security or any other required security amount(s). The Seller shall be responsible for all costs, and receive any interest earned associated with establishing and maintaining the escrow account(s).

Guarantee or Letter of Credit Security – Seller shall post and maintain in an amount equal to the Delay Security or other required security amount(s): (a) a guaranty from a party that satisfies the Credit Requirements, in a form acceptable to Idaho Power at its discretion, or b) an irrevocable_Letter of Credit in a form acceptable to Idaho Power, in favor of Idaho Power. The Letter of Credit will be issued by a financial institution acceptable to both parties. The Seller shall be responsible for all costs associated with establishing and maintaining the Guarantee(s) or Letter(s) of Credit.

APPENDIX E

WIND ENERGY PRODUCTION FORECASTING

As specified in Commission Order 30488, Idaho Power shall make use of a Wind Energy Production Forecasting model to forecast the energy production from this Facility and other Qualifying Facility wind generation resources. Seller and Idaho Power will share the cost of Wind Energy Production Forecasting. The Facility's share of Wind Energy Production Forecasting is determined as specified below. Sellers share will not be greater than 0.1% of the total energy payments made to Seller by Idaho Power during the previous Contract Year.

a. For every month of this Agreement beginning with the first full month after the First Energy Date as specified in Appendix of this Agreement, the Wind Energy Production Forecasting Monthly Cost Allocation (MCA) will be due and payable by the Seller. Any Wind Energy Production Forecasting Monthly Cost Allocations (MCA) that are not reimbursed to Idaho Power shall be deducted from energy payments to the Seller.

- As the value of the 0.1% cap of the Facilities total energy payments will not be known until the first Contract Year is complete, at the end of the first Contract Year any prior allocations that exceeded the 0.1% cap shall be adjusted to reflect the 0.1% cap and if the Facility has paid the monthly allocations a refund will be included in equal monthly amounts over the ensuing Contract Year. If the Facility has not paid the monthly allocations the amount due Idaho Power will be adjusted accordingly and the unpaid balance will be deducted from the ensuing Contract Year's energy payments.

b. During the first Contract Year, as the value of the 0.1% cap of the Facilities total

energy payments will not be known until the first Contract Year is complete, Idaho Power will deduct the Facility's calculated share of the Wind Energy Production Forecasting costs specified in item d each month during the first Contract Year and subsequently refund any overpayment (payments that exceed the cap) in equal monthly amounts over the ensuing Contract Year.

c. The cost allocation formula described below will be reviewed and revised if necessary on the last day of any month in which the cumulative MW nameplate of wind projects having Commission approved agreements to deliver energy to Idaho Power has been revised by an action of the Commission.

d. The monthly cost allocation will be based upon the following formula :

Where: **Total MW (TMW)** is equal to the total nameplate rating of all QF wind projects that are under contract to provide energy to Idaho Power Company.

Facility MW (FMW) is equal to the nameplate rating of this Facility as specified in Appendix B.

Annual Wind Energy Production Forecasting Cost (AFCost) is equal to the total annual cost Idaho Power incurs to provide Wind Energy Production Forecasting. Idaho Power will estimate the AFCost for the current year based upon the previous year's cost and expected costs for the current year. At year-end, Idaho Power will compare the actual costs to the estimated costs and any differences between the estimated AFCost and the actual AFCost will be included in the next year's AFCost.

Annual Cost Allocation (ACA) = AFCost X (FMW / TMW)

And

Monthly Cost Allocation (MCA) = ACA / 12

e. The Wind Energy Production Forecasting Monthly Cost Allocation (MCA) is

due and payable to Idaho Power. The MCA will first be netted against any monthly energy payments owed to the Seller. If the netting of the MCA against the monthly energy payments results in a balance being due Idaho Power, the Facility shall pay this amount within 15 days of the date of the payment invoice.

FIRM ENERGY SALES AGREEMENT

BETWEEN

IDAHO POWER COMPANY

AND

DEEP CREEK WIND PARK, LLC

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FIRM ENERGY SALES AGREEMENT
(10 aMW or Less)

Project Name: Deep Creek Wind Park

Project Number: 31721200

THIS AGREEMENT, entered into on this 10th day of December, 2010 between DEEP CREEK WIND PARK, LLC (Seller), and IDAHO POWER COMPANY, an Idaho corporation (Idaho Power), hereinafter sometimes referred to collectively as "Parties" or individually as "Party."

WITNESSETH:

WHEREAS, Seller will design, construct, own, maintain and operate an electric generation facility; and

WHEREAS, Seller wishes to sell, and Idaho Power is willing to purchase, firm electric energy produced by the Seller's Facility.

THEREFORE, In consideration of the mutual covenants and agreements hereinafter set forth, the Parties agree as follows:

ARTICLE I: DEFINITIONS

As used in this Agreement and the appendices attached hereto, the following terms shall have the following meanings:

1.1 "Availability Shortfall Price" - The current month's Mid-Columbia Market Energy Cost minus the current month's All Hours Energy Price specified in paragraph 7.3 of this Agreement. If this calculation results in a value less than 15.00 Mills/kWh the result shall be 15.00 Mills/kWh.

1.2 "Business Days" - means any calendar day that is not a Saturday, a Sunday, or a NERC recognized holiday.

1.3 "Calculated Net Energy Amount" - A monthly estimate, prepared and documented after the fact by Seller, reviewed and accepted by the Buyer that is the calculated monthly maximum energy deliveries (measured in kWh) for each individual wind turbine, totaled for the Facility to determine the total energy that the Facility could have delivered to Idaho Power during that month based upon: (1) each wind turbine's Nameplate Capacity, (2) Sufficient Prime Mover available for use by each wind turbine during the month, (3) incidents of Force Majeure, (4) scheduled maintenance, or (5) incidents of Forced Outages less Losses and Station Use. If the duration of an event characterized as item 3, 4 or 5 above (measured on each individual occurrence and individual wind turbine) lasts for less than 15 minutes, then the event will not be considered in this calculation. The Seller shall collect and maintain actual data to support this calculation and shall keep this data for a minimum of 3 years.

1.4 "Commission" - The Idaho Public Utilities Commission.

1.5 "Contract Year" - The period commencing each calendar year on the same calendar date as the Operation Date and ending 364 days thereafter.

1.6 "Delay Liquidated Damages" – Damages payable to Idaho Power as calculated in paragraph 5.3, 5.4, 5.5 and 5.6.

1.7 "Delay Period" – All days past the Scheduled Operation Date until the Seller's Facility achieves the Operation Date.

1.8 "Delay Price" - The current month's Mid-Columbia Market Energy Cost minus the current month's All Hours Energy Price specified in paragraph 7.3 of this Agreement. If this calculation results in a value less than 0, the result of this calculation will be 0.

1.9 "Designated Dispatch Facility" - Idaho Power's Systems Operations Group, or any subsequent group designated by Idaho Power.

1.10 "Effective Date" – The date stated in the opening paragraph of this Firm Energy Sales Agreement representing the date upon which this Firm Energy Sales Agreement was fully executed by both Parties.

1.11 "Facility" - That electric generation facility described in Appendix B of this Agreement.

1.12 "First Energy Date" - The day commencing at 00:01 hours, Mountain Time, following the day that Seller has satisfied the requirements of Article IV and the Seller begins delivering energy to the Idaho Power electrical system at the Point of Delivery.

1.13 "Forced Outage" – a partial or total reduction of a) the Facility's capacity to produce and/or deliver Net Energy to the Point of Delivery, or b) Idaho Power's ability to accept Net Energy at the Point of Delivery for non-economic reasons, as a result of Idaho Power or Facility: 1) equipment failure which was **not** the result of negligence or lack of preventative maintenance, or 2) responding to a transmission provider curtailment order, or 3) unplanned preventative maintenance to repair equipment that left unrepaired, would result in failure of equipment prior to the planned maintenance period, or 4) planned maintenance or construction of the Facility or electrical lines required to serve this Facility. The Parties shall make commercially reasonable efforts to perform this unplanned preventative maintenance during periods of low wind availability.

1.14 "Heavy Load Hours" – The daily hours beginning at 7:00 am, ending at 11:00 pm Mountain Time, (16 hours) excluding all hours on all Sundays, New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

1.15 "Inadvertent Energy" – Electric energy Seller does not intend to generate. Inadvertent energy is more particularly described in paragraph 7.5 of this Agreement.

1.16 "Interconnection Facilities" - All equipment specified in Idaho Power's Schedule 72.

1.17 "Initial Capacity Determination" – The process by which Idaho Power confirms that under normal or average design conditions the Facility will generate at no more than 10 average MW per month and is therefore eligible to be paid the published rates in accordance with Commission Order No. 29632.

1.18 "Light Load Hours" – The daily hours beginning at 11:00 pm, ending at 7:00 am Mountain Time (8 hours), plus all other hours on all Sundays, New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

1.19 "Losses" – The loss of electrical energy expressed in kilowatt hours (kWh) occurring as a result of the transformation and transmission of energy between the Metering Point and the point the Facility's energy is delivered to the Idaho Power electrical system. The loss calculation formula will be as specified in Appendix B of this Agreement.

1.20 "Market Energy Reference Price" – Eighty-five percent (85%) of the Mid-Columbia Market Energy Cost.

1.21 "Material Breach" – A Default (paragraph 19.2.1) subject to paragraph 19.2.2.

1.22 "Maximum Capacity Amount" – The maximum capacity (MW) of the Facility will be as specified in Appendix B of this Agreement.

1.23 "Mechanical Availability" - The percentage amount calculated by Seller within 5 days after the end of each month of the Facility's monthly actual Net Energy divided by the Facility's Calculated Net Energy Amount for the applicable month. Any damages due as a result of the Seller falling short of the Mechanical Availability Guarantee for each month shall be determined in accordance with paragraph 6.4.4.

1.24 "Mechanical Availability Guarantee" shall be as defined in paragraph 6.4.

1.25 "Metering Equipment" - All equipment specified in Schedule 72, this Agreement and any additional equipment specified in Appendix B required to measure, record and telemeter bi-directional power flows from the Seller's Facility at the Metering Point.

1.26 "Metering Point" - The physical point at which the Metering Equipment is located that enables accurate measurement of the Test Energy and Net Energy deliveries to Idaho Power at the Point of Delivery for this Facility that provides all necessary data to administer this Agreement.

1.27 "Mid- Columbia Market Energy Cost" – The monthly weighted average of the daily on-peak and off-peak Dow Jones Mid-Columbia Index (Dow Jones Mid-C Index) prices for non-firm energy. If the Dow Jones Mid-Columbia Index price is discontinued by the reporting agency, both Parties will mutually agree upon a replacement index, which is similar to the Dow Jones Mid-Columbia

Index. The selected replacement index will be consistent with other similar agreements and a commonly used index by the electrical industry.

1.28 "Nameplate Capacity" –The full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovolt-amperes, kilowatts, volts or other appropriate units. Usually indicated on a nameplate attached to the individual machine or device.

1.29 "Net Energy" – All of the electric energy produced by the Facility, less Station Use, less Losses, expressed in kilowatt hours (kWh) delivered to Idaho Power at the Point of Delivery. Subject to the terms of this Agreement, Seller commits to deliver all Net Energy to Idaho Power at the Point of Delivery for the full term of the Agreement. Net Energy does not include Inadvertent Energy.

1.30 "Operation Date" – The day commencing at 00:01 hours, Mountain Time, following the day that all requirements of paragraph 5.2 have been completed.

1.31 "Point of Delivery" – The location specified in Appendix B, where Idaho Power's and the Seller's electrical facilities are interconnected and the energy from this Facility is delivered to the Idaho Power electrical system.

1.32 "Prudent Electrical Practices" – Those practices, methods and equipment that are commonly and ordinarily used in electrical engineering and operations to operate electric equipment lawfully, safely, dependably, efficiently and economically.

1.33 "Scheduled Operation Date" – The date specified in Appendix B when Seller anticipates achieving the Operation Date. It is expected that the Scheduled Operation Date provided by the Seller shall be a reasonable estimate of the date that the Seller anticipates that the Seller's Facility shall achieve the Operation Date.

1.34 "Schedule 72" – Idaho Power's Tariff No 101, Schedule 72 or its successor schedules as approved by the Commission. The Seller shall be responsible to pay all costs of interconnection and integration of this Facility into the Idaho Power electrical system as specified within Schedule 72 and this Agreement.

1.35 "Season" – The three periods identified in paragraph 6.2.1 of this Agreement.

1.36 "Special Facilities" - Additions or alterations of transmission and/or distribution lines and transformers as described in Schedule 72.

1.37 "Station Use" – Electric energy that is used to operate equipment that is auxiliary or otherwise related to the production of electricity by the Facility.

1.38 "Sufficient Prime Mover" means wind speed that is (1) equal to or greater than the generation unit's manufacturer-specified minimum levels required for the generation unit to produce energy, and (2) equal to or less than the generation unit's manufacturer-specified maximum levels at which the generation unit can safely produce energy.

1.39 "Surplus Energy" – All Net Energy produced by the Seller's Facility and delivered by the Facility to the Idaho Power electrical system prior to the Operation Date.

1.40 "Total Cost of the Facility" - The total cost of structures, equipment and appurtenances.

1.41 "Wind Energy Production Forecast" – A forecast of energy deliveries from this Facility provided by an Idaho Power administered wind forecasting model. The Facility shall be responsible for an allocated portion of the total costs of the forecasting model as specified in Appendix E.

ARTICLE II: NO RELIANCE ON IDAHO POWER

2.1 Seller Independent Investigation - Seller warrants and represents to Idaho Power that in entering into this Agreement and the undertaking by Seller of the obligations set forth herein, Seller has investigated and determined that it is capable of performing hereunder and has not relied upon the advice, experience or expertise of Idaho Power in connection with the transactions contemplated by this Agreement.

2.2 Seller Independent Experts - All professionals or experts including, but not limited to, engineers, attorneys, or accountants that Seller may have consulted or relied on in undertaking the transactions contemplated by this Agreement have been solely those of Seller.

ARTICLE III: WARRANTIES

3.1 No Warranty by Idaho Power - Any review, acceptance or failure to review Seller's design, specifications, equipment or facilities shall not be an endorsement or a confirmation by Idaho Power and Idaho Power makes no warranties, expressed or implied, regarding any aspect of Seller's design, specifications, equipment or facilities, including, but not limited to, safety, durability, reliability, strength, capacity, adequacy or economic feasibility.

3.2 Qualifying Facility Status - Seller warrants that the Facility is a "Qualifying Facility," as that term is used and defined in 18 CFR 292.201 et seq. After initial qualification, Seller will take such steps as may be required to maintain the Facility's Qualifying Facility status during the term of this Agreement and Seller's failure to maintain Qualifying Facility status will be a Material Breach of this Agreement. Idaho Power reserves the right to review the Facility's Qualifying Facility status and associated support and compliance documents at anytime during the term of this Agreement.

ARTICLE IV: CONDITIONS TO ACCEPTANCE OF ENERGY

4.1 Prior to the First Energy Date and as a condition of Idaho Power's acceptance of deliveries of energy from the Seller under this Agreement, Seller shall:

4.1.1 Submit proof to Idaho Power that all licenses, permits or approvals necessary for Seller's operations have been obtained from applicable federal, state or local authorities, including, but not limited to, evidence of compliance with Subpart B, 18 CFR 292.201 et seq. as a certified Qualifying Facility.

4.1.2 Opinion of Counsel - Submit to Idaho Power an Opinion Letter signed by an attorney admitted to practice and in good standing in the State of Idaho providing an opinion that Seller's licenses, permits and approvals as set forth in paragraph 4.1.1 above are legally and validly issued, are held in the name of the Seller and, based on a reasonable independent review, counsel is of the opinion that Seller is in substantial compliance with said permits as of the date of the Opinion Letter. The Opinion Letter will be in a form acceptable to Idaho Power and will acknowledge that the attorney rendering the opinion understands that Idaho Power is relying on said opinion. Idaho Power's acceptance of the form will not be unreasonably withheld. The Opinion Letter will be governed by and shall be interpreted in accordance with the legal opinion accord of the American Bar Association Section of Business Law (1991).

4.1.3 Initial Capacity Determination - Submit to Idaho Power such data as Idaho Power may reasonably require to perform the Initial Capacity Determination. Such data will include but not be limited to, Nameplate Capacity, equipment specifications, prime mover data, resource characteristics, normal and/or average operating design conditions and Station Use data. Upon receipt of this information, Idaho Power will review the provided data and if necessary, request additional data to complete the Initial Capacity Determination within a reasonable time.

4.1.3.1 If the Maximum Capacity specified in Appendix B of this Agreement and the cumulative manufacture Nameplate Capacity rating of the individual generation units at this Facility is less than 10 MW, the Seller shall submit detailed, manufacturer, verifiable data of the Nameplate Capacity ratings of the actual individual generation units to be installed at this Facility. Upon verification by Idaho Power that the data provided establishes the combined Nameplate Capacity rating of the generation units to be installed at this Facility is less than 10 MW, it will be deemed that the Seller has satisfied the Initial Capacity Determination for this Facility.

4.1.4 Nameplate Capacity – Submit to Idaho Power manufacturer's and engineering documentation that establishes the Nameplate Capacity of each individual generation unit that is included within this entire Facility. Upon receipt of this data, Idaho Power shall review the provided data and determine if the Nameplate Capacity specified is reasonable based upon the manufacturer's specified generation ratings for the specific generation units.

4.1.5 Engineer's Certifications - Submit an executed Engineer's Certification of Design & Construction Adequacy and an Engineer's Certification of Operations and Maintenance (O&M) Policy as described in Commission Order No. 21690. These certificates will be in the form specified in Appendix C but may be modified to the extent necessary to recognize the different engineering disciplines providing the certificates.

4.1.6 Insurance - Submit written proof to Idaho Power of all insurance required in Article XIII.

4.1.7 Interconnection – Provide written confirmation from Idaho Power's delivery business unit that Seller has satisfied all interconnection requirements.

4.1.8 Network Resource Designation – The Seller's Facility has been designated as a network resource capable of delivering firm energy up to the amount of the Maximum Capacity.

4.1.8.1 Seller has provided all information required to enable Idaho Power to file an initial transmission capacity request.

a) Results of the initial transmission capacity request are known and acceptable to the Seller.

b) Seller acknowledges responsibility for all interconnection costs and any costs associated with acquiring adequate firm transmission capacity to enable the project to be classified as an Idaho Power designated firm network resource.

c.) If the Facility is located outside of the Idaho Power service territory, in addition to the above requirements, the Seller must provide evidence that the Seller has acquired firm transmission capacity from all required transmitting entities to deliver the Facility's energy to an acceptable point of delivery on the Idaho Power electrical system.

4.1.9 Written Acceptance – Request and obtain written confirmation from Idaho Power that all conditions to acceptance of energy have been fulfilled. Such written confirmation shall be provided within a commercially reasonable time following the Seller's request and will not be unreasonably withheld by Idaho Power.

ARTICLE V: TERM AND OPERATION DATE

5.1 Term - Subject to the provisions of paragraph 5.2 below, this Agreement shall become effective on the date first written and shall continue in full force and effect for a period of twenty (20) Contract Years from the Operation Date.

5.2 Operation Date - The Operation Date may occur only after the Facility has achieved all of the following:

a) Achieved the First Energy Date.

b) Commission approval of this Agreement in a form acceptable to Idaho Power has been received.

c) Seller has demonstrated to Idaho Power's satisfaction that the Facility is complete and able to provide energy in a consistent, reliable and safe manner.

d) Seller has requested an Operation Date from Idaho Power in a written format.

e) Seller has received written confirmation from Idaho Power of the Operation Date. This confirmation will not be unreasonably withheld by Idaho Power.

5.3 Operation Date Delay - Seller shall cause the Facility to achieve the Operation Date on or before the Scheduled Operation Date. Delays in the interconnection and transmission network upgrade study, design and construction process that **are not** Force Majeure events accepted by both Parties, **shall not** prevent Delay Liquidated Damages from being due and owing as calculated in accordance with this Agreement.

5.3.1 If the Operation Date occurs after the Scheduled Operation Date but on or prior to ninety (90) days following the Scheduled Operation Date, Seller shall pay Idaho Power Delay Liquidated Damages calculated at the end of each calendar month after the Scheduled Operation Date as follows:

Delay Liquidated Damages are equal to ((Current month's Initial Year Net Energy Amount as specified in paragraph 6.2.1 divided by the number of days in the current month) multiplied by the number of days in the Delay Period in the current month) multiplied by the current month's Delay Price.

5.3.2 If the Operation Date does not occur within ninety (90) days following the Scheduled Operation Date, the Seller shall pay Idaho Power Delay Liquidated Damages, in addition to those provided in paragraph 5.3.1, calculated as follows:

Forty five dollars ($45) multiplied by the Maximum Capacity with the Maximum Capacity being measured in kW.

5.4 If Seller fails to achieve the Operation Date within ninety (90) days following the Scheduled Operation Date, such failure will be a Material Breach and Idaho Power may terminate this Agreement at any time until the Seller cures the Material Breach. Additional Delay Liquidated Damages beyond those calculated in 5.3.1 and 5.3.2 will be calculated and payable using the Delay Liquidated Damage calculation described in 5.3.1 above for all days exceeding 90 days past the Scheduled Operation Date until such time as the Seller cures this Material Breach or Idaho Power terminates this Agreement.

5.5 Seller shall pay Idaho Power any calculated Delay Liquidated Damages within seven (7) days of when Idaho Power calculates and presents any Delay Liquidated Damages billings to the Seller. Seller's failure to pay these damages within the specified time will be a Material Breach of this Agreement and Idaho Power shall draw funds from the Delay Security provided by the Seller in an amount equal to the calculated Delay Liquidated Damages.

5.6 The Parties agree that the damages Idaho Power would incur due to delay in the Facility achieving the Operation Date on or before the Scheduled Operation Date would be difficult or impossible to predict with certainty, and that the Delay Liquidated Damages are an appropriate approximation of such damages.

5.7 Prior to the Seller executing this Agreement, the Seller shall have agreed to and executed a Letter of Understanding with Idaho Power that contains at a minimum the following requirements:

a) Seller has filed for interconnection and is in compliance with all payments and requirements of the interconnection process.

b) Seller has provided all information required to enable Idaho Power to file an initial transmission capacity request.

5.8 Within thirty (30) days of the date of a final non-appealable Commission Order as specified in Article XXI approving this Agreement; Seller shall post liquid security ("Delay Security") in a form as described in Appendix D equal to or exceeding the amount calculated in paragraph 5.8.1. Failure to post this Delay Security in the time specified above will be a Material Breach of this Agreement and Idaho Power may terminate this Agreement.

5.8.1 Delay Security The greater of forty five ($45) multiplied by the Maximum Capacity with the Maximum Capacity being measured in kW or the sum of three month's estimated revenue. Where the estimated three months of revenue is the estimated revenue associated with the first three full months following the estimated Scheduled Operation Date, the estimated kWh of energy production as specified in paragraph 6.2.1 for those three months multiplied by the All Hours Energy Price specified in paragraph 7.3 for each of those three months.

5.8.1.1 In the event (a) Seller provides Idaho Power with certification that (1) a generation interconnection agreement specifying a schedule that will enable this Facility to achieve the Operation Date no later than the Scheduled Operation Date has been completed and the Seller has paid all required interconnection costs, or (2) a generation interconnection agreement is substantially complete and all material costs of interconnection have been identified and agreed upon and the Seller is in compliance with all terms and conditions of the generation interconnection agreement, the Delay Security calculated in accordance with paragraph 5.8.1 will be reduced by ten percent (10%).

5.8.1.2 If the Seller has received a reduction in the calculated Delay Security as specified in paragraph 5.8.1.1 and subsequently (1) at Seller's request, the generation interconnection agreement specified in paragraph 5.8.1.1 is revised and as a result the Facility will not achieve its Operation Date by the Scheduled Operation Date, or (2) if the Seller does not maintain compliance with the generation interconnection agreement, the full amount of the Delay Security as calculated in paragraph 5.8.1 will be subject to reinstatement and will be due and owing within five (5) business days from the date Idaho Power requests reinstatement. Failure to timely reinstate the Delay Security will be a Material Breach of this Agreement.

5.8.2 Idaho Power shall release any remaining security posted hereunder after all calculated Delay Liquidated Damages are paid in full to Idaho Power and the earlier of: 1) thirty (30) days after the Operation Date has been achieved, or 2) sixty (60) days after the Agreement has been terminated.

ARTICLE VI: PURCHASE AND SALE OF NET ENERGY

6.1 Delivery and Acceptance of Net Energy - Except when either Party's performance is excused as provided herein, Idaho Power will purchase and Seller will sell all of the Net Energy to Idaho Power at the Point of Delivery. All Inadvertent Energy produced by the Facility will also be delivered by the Seller to Idaho Power at the Point of Delivery. At no time will the total amount of Net Energy and/or Inadvertent Energy produced by the Facility and delivered by the Seller to the Point of Delivery exceed the Maximum Capacity Amount.

6.2 Net Energy Amounts - Seller intends to produce and deliver Net Energy in the following monthly amounts. These amounts shall be consistent with the Mechanical Availability Guarantee.

6.2.1 Initial Year Monthly Net Energy Amounts:

	Month	kWh
Season 1	March	6,128,553
	April	5,679,690
	May	4,597,609
Season 2	July	3,696,361
	August	3,856,621
	November	5,585,873
	December	6,481,286
Season 3	June	3,903,920
	September	4,001,235
	October	4,922,843
	January	6,302,592
	February	6,416,221

6.3 Unless excused by an event of Force Majeure, Seller's failure to deliver Net Energy in any Contract Year in an amount equal to at least ten percent (10%) of the sum of the Initial Year Monthly Net Energy Amounts as specified in paragraph 6.2 shall constitute an event of default.

6.4 Mechanical Availability Guarantee – After the Operational Date has been established, the Facility shall achieve a minimum monthly Mechanical Availability of 85% for the Facility for each month during the full term of this Agreement (the "Mechanical Availability Guarantee"). Failure to achieve the Mechanical Availability Guarantee shall result in Idaho Power calculating damages as specified in paragraph 6.4.4.

6.4.1 At the same time the Seller provides the Monthly Power Production and Availability Report (Appendix A), the Seller shall provide and certify the calculation of the Facility's current month's Mechanical Availability. The Seller shall include a summary of all information used to calculate the Calculated Net Energy Amount including but not limited to: (a) Forced Outages, (b) Force Majeure events, (c) wind speeds and the impact on generation output, and (c) scheduled maintenance and Station Use information.

6.4.2 The Seller shall maintain and retain for three years detailed documentation supporting the monthly calculation of the Facility's Mechanical Availability.

6.4.3 Idaho Power shall have the right to review and audit the documentation supporting the calculation of the Facility's Mechanical Availability at reasonable times at the Seller's offices.

6.4.4 If the current month's Mechanical Availability is less than the Mechanical Availability Guarantee, damages shall be equal to:

((eighty-five (85) percent of the month's Calculated Net Energy Amount) minus the month's actual Net Energy deliveries) multiplied by the Availability Shortfall Price.

6.4.5 Any damages calculated in paragraph 6.4.4 will be offset against the current month's energy payment. If an unpaid balance remains after the damages are offset against the energy payment, the Seller shall pay in full the remaining balance within thirty (30) days of the date of the invoice.

ARTICLE VII: PURCHASE PRICE AND METHOD OF PAYMENT

7.1 Heavy Load Purchase Price – For all Net Energy received during Heavy Load Hours, Idaho Power will pay the non-levelized energy price in accordance with Commission Order 31025 adjusted in accordance with Commission Order 30415 for Heavy Load Hour Energy deliveries, adjusted in accordance with Commission Order 30488 for the wind integration charge, and with seasonalization factors applied:

Year	Season 1 - (73.50 %) Mills/kWh	Season 2 - (120.00 %) Mills/kWh	Season 3 - (100.00 %) Mills/kWh
2010	40.52	66.15	55.12
2011	42.80	69.87	58.24
2012	45.32	74.00	61.66
2013	47.71	78.18	64.92
2014	50.29	82.74	68.42
2015	53.05	87.64	72.17
2016	54.64	90.46	74.34
2017	56.20	93.23	76.61
2018	57.90	96.25	79.12
2019	59.57	99.21	81.59

2020	61.29	102.27	84.14
2021	63.33	105.90	87.16
2022	65.46	109.67	90.31
2023	67.67	113.59	93.57
2024	69.97	117.66	96.97
2025	72.35	121.90	100.50
2026	74.38	125.49	103.49
2027	76.62	129.20	106.58
2028	78.96	133.03	109.77
2029	81.38	136.97	113.06
2030	83.87	141.04	116.45
2031	87.22	146.51	121.01
2032	90.15	151.30	125.00
2033	93.19	156.26	129.13

7.2 Light Load Purchase Price – For all Net Energy received during Light Load Hours, Idaho Power will pay the non-levelized energy price in accordance with Commission Order 31025 adjusted in accordance with Commission Order 30415 for Light Load Hour Energy deliveries, adjusted in accordance with Commission Order 30488 for the wind integration charge, and with seasonalization factors applied:

Year	Season 1 - (73.50 %) Mills/kWh	Season 2 - (120.00 %) Mills/kWh	Season 3 - (100.00 %) Mills/kWh
2010	35.59	58.11	48.42
2011	37.88	61.84	51.54
2012	40.40	65.95	54.96
2013	42.79	69.86	58.22
2014	45.37	74.06	61.72
2015	48.13	78.91	65.48
2016	49.72	81.73	67.64
2017	51.28	84.50	69.76
2018	52.97	87.51	72.07
2019	54.65	90.47	74.35
2020	56.37	93.53	76.86
2021	58.41	97.16	79.88
2022	60.54	100.93	83.03
2023	62.74	104.85	86.29
2024	65.04	108.92	89.69
2025	67.43	113.16	93.22
2026	69.45	116.76	96.21
2027	71.55	120.47	99.30

2028	73.70	124.29	102.49
2029	76.03	128.24	105.78
2030	78.52	132.31	109.17
2031	81.87	137.77	113.73
2032	84.80	142.56	117.72
2033	87.84	147.52	121.85

7.3 All Hours Energy Price – The price to be used in the calculation of the Surplus Energy Price and Delay Price shall be the non-levelized energy price in accordance with Commission Order 31025 adjusted in accordance with Commission Order 30488 for the wind integration charge, and with seasonalization factors applied:

Year	Season 1 - (73.50 %) Mills/kWh	Season 2 - (120.00 %) Mills/kWh	Season 3 - (100.00 %) Mills/kWh
2010	38.33	62.57	52.14
2011	40.61	66.30	55.26
2012	43.13	70.42	58.68
2013	45.52	74.33	61.93
2014	48.10	78.85	65.44
2015	50.86	83.75	69.19
2016	52.45	86.58	71.36
2017	54.01	89.35	73.48
2018	55.71	92.36	75.88
2019	57.37	95.32	78.35
2020	59.10	98.38	80.90
2021	61.14	102.01	83.92
2022	63.27	105.78	87.07
2023	65.48	109.70	90.33
2024	67.78	113.77	93.73
2025	70.16	118.01	97.26
2026	72.18	121.60	100.25
2027	74.28	125.31	103.35
2028	76.58	129.14	106.53
2029	79.00	133.09	109.82
2030	81.49	137.16	113.21
2031	84.84	142.62	117.77
2032	87.77	147.41	121.76
2033	90.81	152.37	125.89

7.4 Surplus Energy Price - For all Surplus Energy, Idaho Power shall pay to the Seller the current month's Market Energy Reference Price or the All Hours Energy Price specified in paragraph

7.3, whichever is lower.

7.5 Inadvertent Energy –

7.5.1 Inadvertent Energy is electric energy produced by the Facility, expressed in kWh, which the Seller delivers to Idaho Power at the Point of Delivery that exceeds 10,000 kW multiplied by the hours in the specific month in which the energy was delivered. (For example January contains 744 hours. 744 hours times 10,000 kW = 7,440,000 kWh. Energy delivered in January in excess of 7,440, 000 kWh in this example would be Inadvertent Energy.)

7.5.2 Although Seller intends to design and operate the Facility to generate no more than ten (10) average MW and therefore does not intend to generate Inadvertent Energy, Idaho Power will accept Inadvertent Energy that does not exceed the Maximum Capacity Amount but will not purchase or pay for Inadvertent Energy.

7.6 Payment Due Date – Undisputed Energy payments, less the Wind Energy Production Forecasting Monthly Cost Allocation (MCA) described in Appendix E and any other payments due Idaho Power, will be disbursed to the Seller within 30 days of the date which Idaho Power receives and accepts the documentation of the monthly Mechanical Available Guarantee and the Net Energy actually delivered to Idaho Power as specified in Appendix A.

7.7 Continuing Jurisdiction of the Commission . This Agreement is a special contract and, as such, the rates, terms and conditions contained in this Agreement will be construed in accordance with Idaho Power Company v. Idaho Public Utilities Commission and Afton Energy, Inc., 107 Idaho 781, 693 P.2d 427 (1984), Idaho Power Company v. Idaho Public Utilities Commission, 107 Idaho 1122, 695 P.2d 1 261 (1985), Afton Energy, Inc, v. Idaho Power Company, 111 Idaho 925, 729 P.2d 400 (1986), Section 210 of the Public Utility Regulatory Policies Act of 1978 and 18 CFR §292.303-308.

ARTICLE VIII: ENVIRONMENTAL ATTRIBUTES

8.1 Seller retains ownership under this Agreement of green tags and renewable energy certificates (RECs), or the equivalent environmental attributes, directly associated with the production of energy from the Seller's Facility sold to Idaho Power.

ARTICLE IX: FACILITY AND INTERCONNECTION

9.1 Design of Facility - Seller will design, construct, install, own, operate and maintain the Facility and any Seller-owned Interconnection Facilities so as to allow safe and reliable generation and delivery of Net Energy and Inadvertent Energy to the Idaho Power Point of Delivery for the full term of the Agreement.

9.2 Interconnection Facilities - Except as specifically provided for in this Agreement, the required Interconnection Facilities will be in accordance with Schedule 72, the Generation Interconnection Process and Appendix B. The Seller is responsible for all costs associated with this equipment as specified in Schedule 72 and the Generation Interconnection Process, including but not limited to initial costs incurred by Idaho Power for equipment costs, installation costs and ongoing monthly Idaho Power operations and maintenance expenses.

ARTICLE X: METERING AND TELEMETRY

10.1 Metering - Idaho Power shall, for the account of Seller, provide, install, and maintain Metering and Telemetry Equipment to be located at a mutually agreed upon location to record and measure power flows to Idaho Power in accordance with this Agreement and Schedule 72. The Metering Equipment will be at the location and the type required to measure, record and report the Facility's Net Energy, Station Use, Inadvertent Energy and maximum energy deliveries (kW) at the Point of Delivery in a manner to provide Idaho Power adequate energy measurement data to administer this Agreement and to integrate this Facility's energy production into the Idaho Power electrical system.

10.2 Telemetry – Idaho Power will install, operate and maintain at Seller's expense metering,

communications and telemetry equipment which will be capable of providing Idaho Power with continuous instantaneous telemetry of Seller's Net Energy and Inadvertent Energy produced and delivered to the Idaho Power Point of Delivery to Idaho Power's Designated Dispatch Facility.

ARTICLE XI - RECORDS

11.1 Maintenance of Records - Seller shall maintain at the Facility or such other location mutually acceptable to the Parties adequate total generation, Net Energy, Station Use, Inadvertent Energy and maximum generation (kW) records in a form and content acceptable to Idaho Power.

11.2 Inspection - Either Party, after reasonable notice to the other Party, shall have the right, during normal business hours, to inspect and audit any or all generation, Net Energy, Station Use, Inadvertent Energy and maximum generation (kW) records pertaining to the Seller's Facility.

ARTICLE XII: OPERATIONS

12 .1 Communications - Idaho Power and the Seller shall maintain appropriate operating communications through Idaho Power's Designated Dispatch Facility in accordance with Appendix A of this Agreement.

12 .2 Energy Acceptance –

12.2.1 Idaho Power shall be excused from accepting and paying for Net Energy or accepting Inadvertent Energy which would have otherwise been produced by the Facility and delivered by the Seller to the Point of Delivery, if it is prevented from doing so by an event of Force Majeure, Forced Outage or temporary disconnection of the Facility in accordance with Schedule 72. If, for reasons other than an event of Force Majeure or a Forced Outage, a temporary disconnection under Schedule 72 exceeds twenty (20) days, beginning with the twenty-first day of such interruption, curtailment or reduction, Seller will be deemed to be delivering Net Energy at a rate equivalent to the pro rata daily average of the amounts specified for the applicable month in paragraph 6.2. Idaho Power will notify Seller when the interruption, curtailment or reduction is terminated.

12.2.2 If, in the reasonable opinion of Idaho Power, Seller's operation of the Facility or Interconnection Facilities is unsafe or may otherwise adversely affect Idaho Power's equipment, personnel or service to its customers, Idaho Power may temporarily disconnect the Facility from Idaho Power's transmission/distribution system as specified within Schedule 72 or take such other reasonable steps as Idaho Power deems appropriate.

12.2.3 Under no circumstances will the Seller deliver Net Energy and/or Inadvertent Energy from the Facility to the Point of Delivery in an amount that exceeds the Maximum Capacity Amount at any moment in time. Seller's failure to limit deliveries to the Maximum Capacity Amount will be a Material Breach of this Agreement.

12.2.4 If Idaho Power is unable to accept the energy from this Facility and is not excused from accepting the Facility's energy, Idaho Power's damages shall be limited to only the value of the estimated energy that Idaho Power was unable to accept. Idaho Power will have no responsibility to pay for any other costs, lost revenue or consequential damages the Facility may incur.

12.3 Scheduled Maintenance – On or before January 31st of each calendar year, Seller shall submit a written proposed maintenance schedule of significant Facility maintenance for that calendar year and Idaho Power and Seller shall mutually agree as to the acceptability of the proposed schedule. The Parties determination as to the acceptability of the Seller's timetable for scheduled maintenance will take into consideration Prudent Electrical Practices, Idaho Power system requirements and the Seller's preferred schedule. Neither Party shall unreasonably withhold acceptance of the proposed maintenance schedule.

12.4 Maintenance Coordination - The Seller and Idaho Power shall, to the extent practical, coordinate their respective line and Facility maintenance schedules such that they occur simultaneously.

12.5 Contact Prior to Curtailment - Idaho Power will make a reasonable attempt to contact the Seller prior to exercising its rights to interrupt interconnection or curtail deliveries from the Seller's

Facility. Seller understands that in the case of emergency circumstances, real time operations of the electrical system, and/or unplanned events Idaho Power may not be able to provide notice to the Seller prior to interruption, curtailment, or reduction of electrical energy deliveries to Idaho Power.

ARTICLE XIII: INDEMNIFICATION AND INSURANCE

13.1 Indemnification - Each Party shall agree to hold harmless and to indemnify the other Party, its officers, agents, affiliates, subsidiaries, parent company and employees against all loss, damage, expense and liability to third persons for injury to or death of person or injury to property, proximately caused by the indemnifying Party's (a) construction, ownership, operation or maintenance of, or by failure of, any of such Party's works or facilities used in connection with this Agreement or (b) negligent or intentional acts, errors or omissions. The indemnifying Party shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity. The indemnifying Party shall pay all documented costs, including reasonable attorney fees that may be incurred by the other Party in enforcing this indemnity.

13.2 Insurance - During the term of this Agreement, Seller shall secure and continuously carry the following insurance coverage:

13.2.1 Comprehensive General Liability Insurance for both bodily injury and property damage with limits equal to $1,000,000, each occurrence, combined single limit. The deductible for such insurance shall be consistent with current Insurance Industry Utility practices for similar property.

13.2.2 The above insurance coverage shall be placed with an insurance company with an A.M. Best Company rating of A- or better and shall include:

(a) An endorsement naming Idaho Power as an additional insured and loss payee as applicable; and

(b) A provision stating that such policy shall not be canceled or the limits of liability reduced without sixty (60) days' prior written notice to Idaho Power.

13.3 Seller to Provide Certificate of Insurance - As required in paragraph 4.1.6 herein and annually thereafter, Seller shall furnish Idaho Power a certificate of insurance, together with the endorsements required therein, evidencing the coverage as set forth above.

13.4 Seller to Notify Idaho Power of Loss of Coverage - If the insurance coverage required by paragraph 13.2 shall lapse for any reason, Seller will immediately notify Idaho Power in writing. The notice will advise Idaho Power of the specific reason for the lapse and the steps Seller is taking to reinstate the coverage. Failure to provide this notice and to expeditiously reinstate or replace the coverage will constitute a Material Breach of this Agreement.

ARTICLE XIV: FORCE MAJEURE

14.1 As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the control of the Seller or of Idaho Power which, despite the exercise of due diligence, such Party is unable to prevent or overcome. Force Majeure includes, but is not limited to, acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, or changes in law or regulation occurring after the Effective Date, which, by the exercise of reasonable foresight such party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome. If either Party is rendered wholly or in part unable to perform its obligations under this Agreement because of an event of Force Majeure, both Parties shall be excused from whatever performance is affected by the event of Force Majeure, provided that:

(1) The non-performing Party shall, as soon as is reasonably possible after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence.

(2) The suspension of performance shall be of no greater scope and of no longer duration than is required by the event of Force Majeure.

(3) No obligations of either Party which arose before the occurrence causing the suspension of performance and which could and should have been fully

performed before such occurrence shall be excused as a result of such occurrence.

ARTICLE XV: LIABILITY; DEDICATION

15.1 Limitation of Liability. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. Neither party shall be liable to the other for any indirect, special, consequential, nor punitive damages, except as expressly authorized by this Agreement.

15.2 Dedication. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the Party or the public or affect the status of Idaho Power as an independent public utility corporation or Seller as an independent individual or entity.

ARTICLE XVI: SEVERAL OBLIGATIONS

16.1 Except where specifically stated in this Agreement to be otherwise, the duties, obligations and liabilities of the Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or impose a trust or partnership duty, obligation or liability on or with regard to either Party. Each Party shall be individually and severally liable for its own obligations under this Agreement.

ARTICLE XVII: WAIVER

17.1 Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent default or other matter.

ARTICLE XVIII: CHOICE OF LAWS AND VENUE

18.1 This Agreement shall be construed and interpreted in accordance with the laws of the State of Idaho without reference to its choice of law provisions.

18.2 Venue for any litigation arising out of or related to this Agreement will lie in the District Court of the Fourth Judicial District of Idaho in and for the County of Ada.

ARTICLE XIX: DISPUTES AND DEFAULT

19.1 Disputes - All disputes related to or arising under this Agreement, including, but not limited to, the interpretation of the terms and conditions of this Agreement, will be submitted to the Commission for resolution.

19.2 Notice of Default

19.2.1 Defaults. If either Party fails to perform any of the terms or conditions of this Agreement (an "event of default"), the non-defaulting Party shall cause notice in writing to be given to the defaulting Party, specifying the manner in which such default occurred. If the defaulting Party shall fail to cure such default within the sixty (60) days after service of such notice, or if the defaulting Party reasonably demonstrates to the other Party that the default can be cured within a commercially reasonable time but not within such sixty (60) day period and then fails to diligently pursue such cure, then, the non-defaulting Party may, at its option, terminate this Agreement and/or pursue its legal or equitable remedies.

19.2.2 Material Breaches – The notice and cure provisions in paragraph 19.2.1 do not apply to defaults identified in this Agreement as Material Breaches. Material Breaches must be cured as expeditiously as possible following occurrence of the breach.

19.3 Security for Performance - Prior to the Operation Date and thereafter for the full term of this Agreement, Seller will provide Idaho Power with the following:

19.3.1 Insurance - Evidence of compliance with the provisions of paragraph 13.2. If Seller

fails to comply, such failure will be a Material Breach and may only be cured by Seller supplying evidence that the required insurance coverage has been replaced or reinstated;

19.3.2 Engineer's Certifications - Every three (3) years after the Operation Date, Seller will supply Idaho Power with a Certification of Ongoing Operations and Maintenance (O&M) from a Registered Professional Engineer licensed in the State of Idaho, which Certification of Ongoing O & M shall be in the form specified in Appendix C. Seller's failure to supply the required certificate will be an event of default. Such a default may only be cured by Seller providing the required certificate; and

19.3.3 Licenses and Permits - During the full term of this Agreement, Seller shall maintain compliance with all permits and licenses described in paragraph 4.1.1 of this Agreement. In addition, Seller will supply Idaho Power with copies of any new or additional permits or licenses. At least every fifth Contract Year, Seller will update the documentation described in Paragraph 4.1.1. If at any time Seller fails to maintain compliance with the permits and licenses described in paragraph 4.1.1 or to provide the documentation required by this paragraph, such failure will be an event of default and may only be cured by Seller submitting to Idaho Power evidence of compliance from the permitting agency.

ARTICLE XX: GOVERNMENTAL AUTHORIZATION

20.1 This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party of this Agreement.

ARTICLE XXI: COMMISSION ORDER

21.1 This Agreement shall become finally effective upon the Commission's approval of all terms and provisions hereof without change or condition and declaration that all payments to be made to Seller hereunder shall be allowed as prudently incurred expenses for ratemaking purposes.

ARTICLE XXII: SUCCESSORS AND ASSIGNS

22.1 This Agreement and all of the terms and provisions hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties hereto, except that no assignment hereof by either Party shall become effective without the written consent of both Parties being first obtained. Such consent shall not be unreasonably withheld. Notwithstanding the foregoing, any party which Idaho Power may consolidate, or into which it may merge, or to which it may convey or transfer substantially all of its electric utility assets, shall automatically, without further act, and without need of consent or approval by the Seller, succeed to all of Idaho Power's rights, obligations and interests under this Agreement. This article shall not prevent a financing entity with recorded or secured rights from exercising all rights and remedies available to it under law or contract. Idaho Power shall have the right to be notified by the financing entity that it is exercising such rights or remedies.

ARTICLE XXIII: MODIFICATION

23.1 No modification to this Agreement shall be valid unless it is in writing and signed by both Parties and subsequently approved by the Commission.

ARTICLE XXIV: TAXES

24.1 Each Party shall pay before delinquency all taxes and other governmental charges which, if failed to be paid when due, could result in a lien upon the Facility or the Interconnection Facilities.

ARTICLE XXV: NOTICES

25.1 All written notices under this Agreement shall be directed as follows and shall be considered delivered when faxed, e-mailed and confirmed with deposit in the U.S. Mail, first-class, postage prepaid, as follows:

To Seller:

Original document to:

James Carkulis
802 W Bannock, ste 1200
Boise, ID 83702
E-mail: crudeen@exergydevelopment.com

To Idaho Power:

Original document to:

Senior Vice President, Power Supply
Idaho Power Company
P.O. Box 70
Boise, Idaho 83707
Email: Lgrow@idahopower.com

Copy of document to:

Cogeneration and Small Power Production
Idaho Power Company
P.O. Box 70
Boise, Idaho 83707
E-mail: rallphin@idahopower.com

Either Party may change the contact person and/or address information listed above, by providing written notice from an authorized person representing the Party.

ARTICLE XXVI: ADDITIONAL TERMS AND CONDITIONS

26.1 This Agreement includes the following appendices, which are attached hereto and included by reference:

Appendix A	-	Monthly Power Production and Availability Report
Appendix B	-	Facility and Point of Delivery
Appendix C	-	Engineer's Certifications
Appendix D	-	Forms of Liquid Security
Appendix E	-	Wind Energy Production Forecasting

ARTICLE XXVII: SEVERABILITY

27.1 The invalidity or unenforceability of any term or provision of this Agreement shall not affect the validity or enforceability of any other terms or provisions and this Agreement shall be construed

in all other respects as if the invalid or unenforceable term or provision were omitted.

ARTICLE XXVIII: COUNTERPARTS

28.1 This Agreement may be executed in two or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

ARTICLE XXIX: ENTIRE AGREEMENT

29.1 This Agreement constitutes the entire Agreement of the Parties concerning the subject matter hereof and supersedes all prior or contemporaneous oral or written agreements between the Parties concerning the subject matter hereof.

IN WITNESS WHEREOF, The Parties hereto have caused this Agreement to be executed in their respective names on the dates set forth below:

Idaho Power Company	Deep Creek Wind Park, LLC
By Lisa A. Grow	By
Lisa A. Grow Sr. Vice President, Power Supply	James Carkulis, Manager
Dated 12·10·10	Dated 09- December. 2010
"Idaho Power"	"Seller"

APPENDIX A

A –1 MONTHLY POWER PRODUCTION AND AVAILABILITY REPORT

At the end of each month the following required documentation will be submitted to:

Idaho Power Company
Attn: Cogeneration and Small Power Production
P.O. Box 70
Boise, Idaho 83707

The meter readings required on this report will be the readings on the Idaho Power Meter Equipment measuring the Facility's total energy production delivered to Idaho Power and Station Usage and the maximum generated energy (kW) as recorded on the Metering Equipment and/or any other required energy measurements to adequately administer this Agreement. This document shall be the document to enable Idaho Power to begin the energy payment calculation and payment process. The meter readings on this report shall not be used to calculate the actual payment, but instead will be a check of the automated meter reading information that will be gathered as described in item A-2 below:

This report shall also include the Seller's calculation of the Mechanical Availability.

Idaho Power Company

Cogeneration and Small Power Production

MONTHLY POWER PRODUCTION AND AVAILABILITY REPORT

Month ____________ **Year** ____________

Project Name ______________________________ **Project Number:** ____________

Address ______________________________ **Phone Number:** ____________

City ____________ **State** ______ **Zip** ____________

	Net Facility Output		Station Usage		Station Usage		Metered Maximum Generation
Meter Number:							
End of Month kWh Meter Reading:							kW
Beginning of Month kWh Meter:							
Difference:							
Times Meter Constant:							**Net Generation**
kWh for the Month:		-		-		=	
Metered Demand:							

Mechanical Availability Guarantee

Seller Calculated Mechanical Availability ______________________________

As specified in this Agreement, the Seller shall include with this monthly report a summary statement of the Mechanical Availability of this Facility for the calendar month. This summary shall include details as to how the Seller calculated this value and summary of the Facility data used in the calculation. Idaho Power and the Seller shall work together to mutually develop a summary report that provides the required data. Idaho Power reserves the right to review the detailed data used in this calculation as allowed within the Agreement.

______________________________ ____________

Signature **Date**

A-2 AUTOMATED METER READING COLLECTION PROCESS

Monthly, Idaho Power will use the provided Metering and Telemetry equipment and processes to collect the meter reading information from the Idaho Power provided Metering Equipment that measures the Net Energy and energy delivered to supply Station Use for the Facility recorded at 12:00 AM (Midnight) of the last day of the month.

The meter information collected will include but not be limited to energy production, Station Use, the maximum generation (kW) and any other required energy measurements to adequately administer this Agreement.

A-3 ROUTINE REPORTING

Idaho Power Contact Information

Daily Energy Production Reporting

Call daily by 10 a.m., 1-800-356-4328 or 1-800-635-1093 and leave the following information:

- Project Identification - Project Name and Project Number
- Current Meter Reading
- Estimated Generation for the current day
- Estimated Generation for the next day

Planned and Unplanned Project outages

Call 1-800-345-1319 and leave the following information:

- Project Identification - Project Name and Project Number
- Approximate time outage occurred

Estimated day and time of project coming back online

Seller's Contact Information

24-Hour Project Operational Contact

Name: ________________
Telephone Number: ________________
Cell Phone: ________________

Project On-site Contact information

Telephone Number: ______________________

APPENDIX B

FACILITY AND POINT OF DELIVERY

Project Name: Deep Creek Wind Park

Project Number: 31721200

B-1 DESCRIPTION OF FACILITY

(Must include the Nameplate Capacity rating and VAR capability (both leading and lagging) of all generation units to be included in the Facility.)

The facility will consist of thirteen 1.6 MW wind turbine generators, with a combined nameplate limited to 20 MW. VAR capability is .95 to .95 leading and lagging.

B-2 LOCATION OF FACILITY

Near: Rogerson, ID

T14S R15E

SEC 11: ALL SEC 14: ALL SEC 15: S1/2, S1/2NE1/4 SEC 22: ALL SEC 23: W1/2W1/2, NE1/4NW1/4 SEC 27: NE1/4, N1/2NW1/4, SE1/4NW1/4

County: Twin Falls, ID.

Description of Interconnection Location: N42° 12.74327, W114° 42.55795

Nearest Idaho Power Substation: ______________________________

B-3 SCHEDULED FIRST ENERGY AND OPERATION DATE

Seller has selected May 30, 2012 as the Scheduled First Energy Date.

Seller has selected June 30, 2012 as the Scheduled Operation Date.

In making these selections, Seller recognizes that adequate testing of the Facility and completion of all requirements in paragraph 5.2 of this Agreement must be completed prior to the project being granted an Operation Date.

B-4 MAXIMUM CAPACITY AMOUNT:

This value will be 20 MW which is consistent with the value provided by the Seller to Idaho Power in accordance with Schedule 72. This value is the maximum energy (MW) that potentially could be delivered by the Seller's Facility to the Idaho Power electrical system at any moment in time.

B-5 POINT OF DELIVERY

"Point of Delivery" means, unless otherwise agreed by both Parties, the point of where the Sellers Facility's energy is delivered to the Idaho Power electrical system. Schedule 72 will determine the specific Point of Delivery for this Facility. The Point of Delivery identified by Schedule 72 will become an integral part of this Agreement.

B-6 LOSSES

If the Idaho Power Metering equipment is capable of measuring the exact energy deliveries by the Seller to the Idaho Power electrical system at the Point of Delivery, no Losses will be calculated for this Facility. If the Idaho Power Metering equipment is unable to measure the exact energy deliveries by the Seller to the Idaho Power electrical system at the Point of Delivery, a Losses calculation will be established to measure the energy losses (kWh) between the Seller's Facility and the Idaho Power Point of Delivery. This loss calculation will be initially set at 2% of the kWh energy production recorded on the Facility generation metering equipment. At such time as Seller provides Idaho Power with the electrical equipment specifications (transformer loss specifications, conductor sizes, etc.) of all of the electrical equipment between the Facility and the Idaho Power electrical system, Idaho Power will configure a revised loss calculation formula to be agreed to by both parties and used to calculate the kWh Losses for the remaining term of the Agreement. If at any time during the term of this Agreement, Idaho Power determines that the loss calculation does not correctly reflect the actual kWh losses attributed to the electrical equipment between the Facility and the Idaho Power electrical system, Idaho Power may adjust the calculation and retroactively adjust the previous months kWh loss calculations.

B-7 METERING AND TELEMETRY

Schedule 72 will determine the specific metering and telemetry requirements for this Facility. At the minimum, the Metering Equipment and Telemetry equipment must be able to provide and record hourly energy deliveries to the Point of Delivery and any other energy measurements required to administer this Agreement. These specifications will include but not be limited to equipment specifications, equipment location, Idaho Power provided equipment, Seller provided equipment, and all costs associated with the equipment, design and installation of the Idaho Power provided equipment. Seller will arrange for and make available at Seller's cost communication circuit(s) compatible with Idaho Power's communications equipment and dedicated to Idaho Power's use terminating at the Idaho Power facilities capable of providing Idaho Power with continuous instantaneous information on the Facilities energy production. Idaho Power provided equipment will be owned and maintained by Idaho Power, with total cost of purchase, installation, operation, and maintenance, including administrative cost to be reimbursed to Idaho Power by the Seller. Payment of these costs will be in accordance with Schedule 72 and the total metering cost will be included in the calculation of the Monthly Operation and Maintenance Charges specified in Schedule 72.

B-8 NETWORK RESOURCE DESIGNATION

Idaho Power cannot accept or pay for generation from this Facility until a Network Resource Designation ("NRD") application has been accepted by Idaho Power's delivery business unit. Federal Energy Regulatory Commission ("FERC") rules require Idaho Power to prepare and submit the NRD. Because much of the information Idaho Power needs to prepare the NRD is specific to the Seller's Facility, Idaho Power's ability to file the NRD in a timely manner is contingent upon timely receipt of the required information from the Seller. Prior to Idaho Power beginning the process to enable Idaho Power to submit a request for NRD status for this Facility, the Seller shall have completed all requirements as specified in Paragraph 5.7 of this Agreement. **Seller's failure to provide complete and accurate information in a timely manner can**

significantly impact Idaho Power's ability and cost to attain the NRD designation for the Seller's Facility and the Seller shall bear the costs of any of these delays that are a result of any action or inaction by the Seller.

APPENDIX C

ENGINEER'S CERTIFICATION

OF

OPERATIONS & MAINTENANCE POLICY

The undersigned ______________________________, on behalf of himself/herself and __________, hereinafter collectively referred to as "Engineer," hereby states and certifies to the Seller as follows:

1. That Engineer is a Licensed Professional Engineer in good standing in the State of Idaho.

2. That Engineer has reviewed the Energy Sales Agreement, hereinafter "Agreement," between Idaho Power as Buyer, and ______________ as Seller, dated ______________________.

3. That the cogeneration or small power production project which is the subject of the Agreement and this Statement is identified as IPCo Facility No. ______________ and is hereinafter referred to as the "Project."

4. That the Project, which is commonly known as the __________________ Project, is located in Section _____ Township ________ Range _______, Boise Meridian, _________ County, Idaho.

5. That Engineer recognizes that the Agreement provides for the Project to furnish electrical energy to Idaho Power for a 20 year period.

6. That Engineer has substantial experience in the design, construction and operation of electric power plants of the same type as this Project.

7. That Engineer has no economic relationship to the Design Engineer of this Project.

8. That Engineer has reviewed and/or supervised the review of the Policy for Operation and Maintenance ("O&M") for this Project and it is his professional opinion that, provided said Project has been designed and built to appropriate standards, adherence to said O&M Policy will result in the Project's producing at or near the design electrical output, efficiency and plant factor for a 20 year period.

9. That Engineer recognizes that Idaho Power, in accordance with paragraph 5.2 of the Agreement, is relying on Engineer's representations and opinions contained in this Statement.

10. That Engineer certifies that the above statements are complete, true and accurate to the best of his/her knowledge and therefore sets his/her hand and seal below.

By ______________________

(P.E. Stamp)

Date ______________________

APPENDIX C

ENGINEER'S CERTIFICATION

OF

ONGOING OPERATIONS AND MAINTENANCE

The undersigned ______________________________, on behalf of himself/herself and ______________________ hereinafter collectively referred to as "Engineer," hereby states and certifies to the Seller as follows:

1. That Engineer is a Licensed Professional Engineer in good standing in the State of Idaho.

2. That Engineer has reviewed the Energy Sales Agreement, hereinafter "Agreement," between Idaho Power as Buyer, and __________________ as Seller, dated ______________________.

3. That the cogeneration or small power production project which is the subject of the Agreement and this Statement is identified as IPCo Facility No. ____________ and hereinafter referred to as the "Project".

4. That the Project, which is commonly known as the __________________ Project, is located in Section _____ Township ________ Range _______, Boise Meridian, __________ County, Idaho.

5. That Engineer recognizes that the Agreement provides for the Project to furnish electrical energy to Idaho Power for a 20 year period.

6. That Engineer has substantial experience in the design, construction and operation of electric power plants of the same type as this Project.

7. That Engineer has no economic relationship to the Design Engineer of this Project.

8. That Engineer has made a physical inspection of said Project, its operations and maintenance records since the last previous certified inspection. It is Engineer's professional opinion, based on the Project's appearance, that its ongoing O&M has been substantially in accordance with said O&M Policy; that it is in reasonably good operating condition; and that if adherence to said O&M Policy continues, the Project will continue producing at or near its design electrical output, efficiency and plant factor for the remaining ______ years of the Agreement.

9. That Engineer recognizes that Idaho Power, in accordance with paragraph 5.2 of the Agreement, is relying on Engineer's representations and opinions contained in this Statement.

10. That Engineer certifies that the above statements are complete, true and accurate to the best of his/her knowledge and therefore sets his/her hand and seal below.

By ______________________________

(P.E. Stamp)

Date ______________________________

APPENDIX C

ENGINEER'S CERTIFICATION

OF

DESIGN & CONSTRUCTION ADEQUACY

The undersigned ____________________________, on behalf of himself/herself and ____________________ hereinafter collectively referred to as "Engineer", hereby states and certifies to Idaho Power as follows:

1. That Engineer is a Licensed Professional Engineer in good standing in the State of Idaho.

2. That Engineer has reviewed the Firm Energy Sales Agreement, hereinafter "Agreement", between Idaho Power as Buyer, and ______________________ as Seller, dated ________, ________________________.

3. That the cogeneration or small power production project, which is the subject of the Agreement and this Statement, is identified as IPCo Facility No ____________ and is hereinafter referred to as the "Project".

4. That the Project, which is commonly known as the _______________ Project, is located in Section _____ Township ________ Range _______, Boise Meridian, __________ County, Idaho.

5. That Engineer recognizes that the Agreement provides for the Project to furnish electrical energy to Idaho Power for a 20 year period.

6. That Engineer has substantial experience in the design, construction and operation of electric power plants of the same type as this Project.

7. That Engineer has no economic relationship to the Design Engineer of this Project and has made the analysis of the plans and specifications independently.

8. That Engineer has reviewed the engineering design and construction of the Project, including the civil work, electrical work, generating equipment, prime mover conveyance system, Seller furnished Interconnection Facilities and other Project facilities and equipment.

9. That the Project has been constructed in accordance with said plans and specifications, all applicable codes and consistent with Prudent Electrical Practices as that term is described in the Agreement.

10. That the design and construction of the Project is such that with reasonable and prudent operation and maintenance practices by Seller, the Project is capable of performing in accordance with the terms of the Agreement and with Prudent Electrical Practices for a 20 year period.

11. That Engineer recognizes that Idaho Power, in accordance with paragraph 5.2 of the Agreement, in interconnecting the Project with its system, is relying on Engineer's representations and opinions contained in this Statement.

12. That Engineer certifies that the above statements are complete, true and accurate to the best of his/her knowledge and therefore sets his/her hand and seal below.

By ________________________________
(P.E. Stamp)

Date ______________________________

APPENDIX D

FORMS OF LIQUID SECURITY

The Seller shall provide Idaho Power with commercially reasonable security instruments such as Cash Escrow Security, Guarantee or Letter of Credit as those terms are defined below or other forms of liquid financial security that would provide readily available cash to Idaho Power to satisfy the Delay Security requirement and any other security requirement within this Agreement.

For the purpose of this Appendix D, the term "Credit Requirements" shall mean acceptable financial creditworthiness of the entity providing the security instrument in relation to the term of the obligation in the reasonable judgment of Idaho Power, provided that any guarantee and/or letter of credit issued by any other entity with a short-term or long-term investment grade credit rating by Standard & Poor's Corporation or Moody's Investor Services, Inc. shall be deemed to have acceptable financial creditworthiness.

1. Cash Escrow Security – Seller shall deposit funds in an escrow account established by the Seller in a banking institution acceptable to both Parties equal to the Delay Security or any other required security amount(s). The Seller shall be responsible for all costs, and receive any interest earned associated with establishing and maintaining the escrow account(s).

Guarantee or Letter of Credit Security – Seller shall post and maintain in an amount equal to the Delay Security or other required security amount(s): (a) a guaranty from a party that satisfies the Credit Requirements, in a form acceptable to Idaho Power at its discretion, or b) an irrevocable Letter of Credit in a form acceptable to Idaho Power, in favor of Idaho Power. The Letter of Credit will be issued by a financial institution acceptable to both parties. The Seller shall be responsible for all costs associated with establishing and maintaining the Guarantee(s) or Letter(s) of Credit.

APPENDIX E

WIND ENERGY PRODUCTION FORECASTING

As specified in Commission Order 30488, Idaho Power shall make use of a Wind Energy Production Forecasting model to forecast the energy production from this Facility and other Qualifying Facility wind generation resources. Seller and Idaho Power will share the cost of Wind Energy Production Forecasting. The Facility's share of Wind Energy Production Forecasting is determined as specified below. Sellers share will not be greater than 0.1% of the total energy payments made to Seller by Idaho Power during the previous Contract Year.

a. For every month of this Agreement beginning with the first full month after the First Energy Date as specified in Appendix of this Agreement, the Wind Energy Production Forecasting Monthly Cost Allocation (MCA) will be due and payable by the Seller. Any Wind Energy Production Forecasting Monthly Cost Allocations (MCA) that are not reimbursed to Idaho Power shall be deducted from energy payments to the Seller.

   - As the value of the 0.1% cap of the Facilities total energy payments will not be known until the first Contract Year is complete, at the end of the first Contract Year any prior allocations that exceeded the 0.1% cap shall be adjusted to reflect the 0.1% cap and if the Facility has paid the monthly allocations a refund will be included in equal monthly amounts over the ensuing Contract Year. If the Facility has not paid the monthly allocations the amount due Idaho Power will be adjusted accordingly and the unpaid balance will be deducted from the ensuing Contract Year's energy payments.

b. During the first Contract Year, as the value of the 0.1% cap of the Facilities total

energy payments will not be known until the first Contract Year is complete, Idaho Power will deduct the Facility's calculated share of the Wind Energy Production Forecasting costs specified in item d each month during the first Contract Year and subsequently refund any overpayment (payments that exceed the cap) in equal monthly amounts over the ensuing Contract Year.

c. The cost allocation formula described below will be reviewed and revised if necessary on the last day of any month in which the cumulative MW nameplate of wind projects having Commission approved agreements to deliver energy to Idaho Power has been revised by an action of the Commission.

d. The monthly cost allocation will be based upon the following formula :

Where: **Total MW (TMW)** is equal to the total nameplate rating of all QF wind projects that are under contract to provide energy to Idaho Power Company.

Facility MW (FMW) is equal to the nameplate rating of this Facility as specified in Appendix B.

Annual Wind Energy Production Forecasting Cost (AFCost) is equal to the total annual cost Idaho Power incurs to provide Wind Energy Production Forecasting. Idaho Power will estimate the AFCost for the current year based upon the previous year's cost and expected costs for the current year. At year-end, Idaho Power will compare the actual costs to the estimated costs and any differences between the estimated AFCost and the actual AFCost will be included in the next year's AFCost.

Annual Cost Allocation (ACA) = AFCost X (FMW / TMW)

And

Monthly Cost Allocation (MCA) = ACA / 12

e. The Wind Energy Production Forecasting Monthly Cost Allocation (MCA) is

due and payable to Idaho Power. The MCA will first be netted against any monthly energy payments owed to the Seller. If the netting of the MCA against the monthly energy payments results in a balance being due Idaho Power, the Facility shall pay this amount within 15 days of the date of the payment invoice.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 26

GENERATOR INTERCONNECTION
SYSTEM IMPACT STUDY

for integration of the proposed

IPC Project Q#322, #323, & #324

in

TWIN FALLS COUNTY, IDAHO

to the

IDAHO POWER COMPANY ELECTRICAL SYSTEM

for

the

INTERCONNECTION CUSTOMER

FINAL REPORT

December 15, 2010

JLE

1.0 Introduction

The Interconnection Customer has contracted with Idaho Power Company (IPC) to perform a System Impact Study (SIS) for the integration of IPC Generation Interconnection Project Queue #322, 323, & 324, three 20 MW wind projects (all to be further referred to as The Projects). The Projects are located in IPCs southern service territory in Twin Falls County, Idaho. The new generation will be connected to the IPC 138 kV system at a new station located under the Upper Salmon – Wells 138 kV line. The point of interconnection to IPC will be the customer side of the generator interconnection package.

This report documents the basis for and the results of this SIS for the proposed three 20 MW wind generation projects. It describes the proposed projects, the impact of associated projects and results of all work in the areas of concern.

2.0 Summary

This SIS looks at two items: (1) Local interconnection requirements for the interconnection of The Projects to IPCs Upper Salmon – Wells 138 kV line, and (2) Transient stability of The Projects.

IPC Transmission Network Upgrades may be necessary if firm transmission is required to deliver The Projects generation from the point of interconnection (point of receipt) to a point of delivery. A transmission service request (TSR) will be required to secure transmission rights on the IPC system, either through latent capacity, or Network Upgrades. Either the interconnection customer, or the merchant purchasing the generation from the interconnection customer, will have to make this TSR. Transmission rights are beyond the scope of this Generation Interconnection System Impact Study. **IPC Transmission Network Upgrade costs are not included in this GI SIS, however, costs could be sizeable.**

Local Interconnection Requirements

If firm transmission is required, the Upper Salmon – Blue Gulch 138 kV line (10.2 miles) will have to be rebuilt in order to integrate the first 20 MW (ProjectQ#322) of The Project. The first 20 MW can be integrated with 10 MW of firm transmission and 10 MW of non-firm transmission without the rebuild. This integration will require the addition of an overload mitigation scheme at the point of interconnection. Transmission is only "firm" as far as Upper Salmon; a TSR will be required to secure transmission rights on the remaining IPC system.

In order to integrate the second 20 MW (ProjectQ#323), 40 MW total, the Upper Salmon – Blue Gulch line must be rebuilt. An overload mitigation scheme is not required, and will offer no benefit.

In order to integrate the last 20 MW (ProjectQ#324), 60 MW total, if firm transmission is required, the entire 138 kV transmission line from the point of interconnection to Upper Salmon will have to be rebuilt. The Projects can be integrated with 50 MW of firm transmission and 10 MW of non-firm transmission with the 10.2 mile Upper Salmon – Blue Gulch 138 kV rebuild and an overload mitigation scheme. Transmission is only "firm" as far as Upper Salmon; a TSR will be required to secure transmission rights on the remaining IPC system.

Integration of any of all of The Projects requires the addition of a new substation. IPCs section of the new substation will consist of at least one 138 kV breaker and potentially a building to house protection equipment including the generation interconnection package. The point of interconnection will be on the customer side of the generator interconnection package.

The generation step up transformer will be connected as a solidly grounded wye on the high (transmission) side.

Transient Stability of The Projects

Select outages were studied using GE PSLF software. The stability analysis performed demonstrated that, for the initial conditions and outages examined, the system was stable and damped and that none of the results exceeded the stated voltage or frequency stability criteria on the system external to The Projects. IPC does not anticipate that any additional transmission system modifications will have to be made to arrest or otherwise manage any stability issues as a result of introducing the proposed new resource to the transmission system.

3.0 Scope of Interconnection System Impact Study

The Interconnection System Impact Study was done and prepared in accordance with Idaho Power Company Standard Generator Interconnection Procedures, to provide a detailed evaluation of the interconnection of the proposed generating project to the Idaho Power system. As listed in Section 5.0 of the Interconnection System Impact Study agreement, the Interconnection System Impact Study report provides the following information:

- identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;
- identification of any thermal overload or voltage limit violations resulting from the interconnection;
- identification of any instability or inadequately damped response to system disturbances resulting from the interconnection; and
- description and non-binding, good faith estimated cost of facilities required to interconnect the Large Generating Facility to the Transmission System and to address the identified short circuit, stability, and power flow issues.

All other proposed Generation projects prior to this project in the Generator Interconnect queue were considered in this study. A current list of these projects can be found on the Idaho Power web site, **http://www.oatioasis.com/ipco/index.html.**

4.0 Description of Proposed Generating Project

The Projects consist of three 20 MW wind generation projects, ProjectQ#322, #323, and #324.

At a new station, under the Upper Salmon – Wells 138 kV line, the generation will interconnect to the IPC system.

The proposed in-service date for this project is December 2011.

5.0 Local Area 138 kV Facility Upgrades

5.1 Transmission Line Facilities

Idaho Power's Upper Salmon – Wells 138 kV transmission line serves the interconnection area. Due to the age and lack of growth in the area, the Upper Salmon – Wells 138 kV line has deteriorated and upgrades have not been carried out. Due to this, the rating of the line has been recommended at 50 MVA. Considering other projects ahead of The Projects in the IPC Generation Interconnection queue, there is not transmission capacity available on this line to serve The Projects.

There is capacity for one 20 MW project, without extensive upgrades, if load south of the point of interconnection always remains online (load always exceeds 10 MW). If load at Wells were to trip offline, and generation on the Upper Salmon – Wells 138 kV line was peaking, the Upper Salmon – Blue Gulch line would overload beyond the 50 MW limit.

If firm transmission is required, the Upper Salmon – Blue Gulch 138 kV line (10.2 miles) will have to be rebuilt in order to integrate the first 20 MW (ProjectQ#322) of The Project. The first 20 MW can be integrated with 10 MW of firm transmission and 10 MW of non-firm transmission without the rebuild. This integration will require the addition of an overload mitigation scheme at the point of interconnection; transmission flow will be limited to 10 MW north (20 MW generation minus 10 MW assumed load south) from the point of interconnection to Blue Gulch. Transmission is only firm as far as Upper Salmon; a TSR will be required to secure transmission rights on the remaining IPC system.

In order to integrate the second 20 MW (ProjectQ#323), 40 MW total, the Upper Salmon – Blue Gulch line must be rebuilt. An overload mitigation scheme is not required, and will offer no benefit.

In order to integrate the last 20 MW (ProjectQ#324), 60 MW total, if firm transmission is required, the entire 138 kV transmission line from the point of interconnection to Upper Salmon will have to be rebuilt. The Projects can be integrated with 50 MW of firm transmission and 10 MW of non-firm transmission with the 10.2 mile Upper Salmon – Blue Gulch 138 kV rebuild and an overload mitigation scheme. Transmission is only firm as far as Upper Salmon; a TSR will be required to secure transmission rights on the remaining IPC system.

5.2 *Substation Facilities*

The Projects will be interconnected at a new 138 kV class substation. IPCs section of the new substation will consist of at least one 138 kV breaker and potentially a building to house protection equipment including the generation interconnection package. The point of interconnection will be on the customer side of the generator interconnection package.

The generation step up transformer will be connected as a solidly grounded wye on the high (transmission) side.

Studies indicate that there is adequate short circuit interrupting capability on breakers in the area for the addition of this generation project. Protective relaying and communications upgrades may be required in adjacent substations.

6.0 Operational Considerations

Connecting The Projects to the Upper Salmon – Wells 138 kV line offers some major problems in terms of voltage control. Without absorbing a significant amount of VARs (at least 13 MVARs), the voltage at the point of interconnection exceeds 1.05 per unit. This study assumes that the generators at the three projects will be Type 3 machines, capable of +/- 0.95 operation. The Projects should be capable of +/- 0.95 power factor operation, as measured at the interconnection point, for all MW production levels from zero MW output to full rated MW output. The interconnection customer will be provided a voltage schedule from Idaho Power Grid Operations prior to Commercial Operation of the project. These projects cannot interconnect without +/- 0.95 power factor capability.

If The Projects use units other than Type 3 wind turbine generators, the interconnection customer must work with IPC to determine the amount of switched capacitors/reactors and possible SVC (dynamic VAR) type devices required to interconnect the project and mitigate high voltage concerns.

7.0 Network Integration of The Projects

Depending on where The Project wishes to sell their generation, Network Upgrades may be required to transmit the power from the point of receipt to the point of delivery. A transmission service request will be required to secure transmission rights on the IPC system. Generation Interconnection System Impact Studies cannot allocate transmission service.

In order to utilize the generation on the IPC system, The Projects' generation will be transmitted to IPCs growing Treasure Valley (Boise) area. Midpoint West, an internal IPC transmission path, is a bottleneck between The Projects & Boise. In order to increase Midpoint West an additional 60 MW, a new 230 kV transmission line between Midpoint and the Treasure Valley would be required. At this point, IPC is not considering options for new 230 kV west out of Midpoint as network upgrades. IPC is in the early stages of a 500 kV transmission project known as Gateway West, which will eventually connect Midpoint to the Treasure Valley. Gateway West will increase the transmission capacity of the Midpoint West cut-plane by well over 60 MW, however this project is not scheduled for completion until sometime after 2014. Between The Projects' in-service date and completion of the Midpoint – Treasure Valley portion of the Gateway West project, The Projects would have to operate as a conditional firm resource, available to be tripped offline if there are problems on the system. A transmission service request will be required to secure transmission rights on the IPC system, and this new transmission project.

8.0 Transient Stability of The Projects

Select outages were studied using GE PSLF software. The stability analysis performed demonstrated that, for the initial conditions and outages examined, the system was stable and damped and that none of the results exceeded the stated voltage or frequency stability criteria on the system external to The Projects. IPC does not anticipate that any additional transmission system modifications will have to be made to arrest or otherwise manage any stability issues as a result of introducing the proposed new resource to the transmission system.

9.0 Description and Cost Estimate of Required Facility Upgrades

The following table lists cost estimates of the directly assignable costs for the upgrades needed to accommodate the proposed project. Allowance for funds used during construction (AFUDC) has not been included in the cost estimates since it is assumed that IPC will be provided up-front funding by the Project. No attempt has been made in this study to assign network upgrade costs and not all of the estimated facility costs are necessarily the responsibility of the Project. These are cost estimates only and final charges to the customer will be based on the actual construction costs incurred. Note that this estimate does not include the cost of the customer's equipment.

Table 1. Estimated Costs for Required Idaho Power Local Area Upgrades

Description	Cost
10.2 mile 138 kV line	$5,000,000
Generation Interconnection Package	$250,000
Total Estimated Cost	**$5,250,000**

Costs for potential Network Upgrades are not included, but could be sizable.

10.0 Conclusions

The requested interconnection of ProjectQ#322, #323, & #324 to Idaho Power's system was studied. The result of this work indicates that the local area Idaho Power transmission system can be upgraded to support this project. The estimated costs of the modifications required, excluding potential network transmission upgrades, are listed in Section 9.0 of this report. These are estimated costs only and final charges to the customer will be based on the actual construction costs incurred.

Next, a facility study will be required to look at the requirements from a construction standpoint. The Facility Study will yield a much more detailed and thorough cost estimate.

APPENDIX A

A-1.0 Method of Study

The System Impact Study inserts the Project up to the maximum requested injection into the selected Western Electric Coordinating Council (WECC) power flow case and then, using GE's Positive Sequence Load Flow (PSLF) analysis tools or Power World Simulator, examines the impacts of the new resource on Idaho Power's system (lines, transformers, etc.) within the study area under various operating/outage scenarios. The WECC and Idaho Power reliability criteria and Idaho Power operating procedures were used to determine the acceptability of the configurations considered. The WECC case is a recent case modified to simulate stressed but reasonable pre-contingency energy transfers utilizing the IPC system.

A-2.0 Acceptability Criteria

The following acceptability criteria were used in the power flow analysis to determine under which system configuration modifications may be required:

> The continuous rating of equipment is assumed to be the normal thermal rating of the equipment. This rating will be as determined by the manufacturer of the equipment or as determined by Idaho Power. Less than or equal to 100% of continuous rating is acceptable.
>
> Idaho Power's Voltage Operating Guidelines were used to determine voltage requirements on the system. This states, in part, that distribution voltages, under normal operating conditions, are to be maintained within plus or minus 5% (0.05 per unit) of nominal everywhere on the feeder. Therefore, voltages greater than or equal to 0.95 pu voltage and less than or equal to 1.05 pu voltage are acceptable.
>
> All customer generation must meet IEEE 519 and ANSI C84.1 Standards.
>
> All other applicable national and Idaho Power standards and prudent utility practices were used to determine the acceptability of the configurations considered.
>
> The stable operation of the system requires an adequate supply of volt-amperes reactive (VARs) to maintain a stable voltage profile under both steady-state and dynamic system conditions. An inadequate supply of VARs will result in voltage decay or even collapse under the worst conditions.

Equipment/line/path ratings used will be those that are in use at the time of the study or that are represented by IPC upgrade projects that are either currently under construction or whose budgets have been approved for construction in the near future. All other potential future ratings are outside the scope of this study. Future transmission changes may, however, affect current facility ratings used in the study.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 27

TRANSMISSION SERVICE REQUEST
SYSTEM IMPACT STUDY REPORT

for the

IDAHO POWER MERCHANT

for

OASIS REFERENCE NUMBERS
74705988 20 MW
74705990 20 MW
74705993 20 MW
74705995 20 MW
[redacted]

from

MDSK (POR) to IPCO (POD)

to

IDAHO POWER COMPANY, Transmission Provider
TRANSMISSION SYSTEM

FINAL V.2 REPORT

December 28, 2010

1.0 Introduction

The Idaho Power Merchant (IPCM) has contracted with Idaho Power Transmission Delivery (IPC) to perform a combined Transmission Service System Impact Study for Network Transmission Service for 85 MW from the MDSK Point of Delivery (POD) to the IPCO Point of Receipt (POR). The 85 MW is made up of five different requests, with the following OASIS reference numbers:

74705988	20 MW
74705990	20 MW
74705993	20 MW
74705995	20 MW
[redacted]	[redacted]

The five different requests will hereafter be referred to as simply The Requests.

This report documents the basis for and the results of this System Impact Study. It describes the required backbone transmission system improvements, the study cases used, outage scenarios assumed and results of all work in the areas of concern. This report satisfies the system impact study requirements of the Idaho Power Tariff.

2.0 Study Assumptions

This Transmission System Impact Study evaluated the performance of the IPC transmission system with 85 additional MW from MDSK (POD) to MPSN (POR). Of the 85 MW, 60 MW was modeled on the Upper Salmon – Wells 138 kV line, and [redacted]

3.0 Summary

A Transmission System Impact Study was performed for 85 MW of addition transfers between MDSK and IPCO on the Idaho Power Transmission System. In order to travel from MDSK to IPCO, power must flow across the Midpoint West and the Boise East internal cut-planes. Given the location of the projects, the existing transmission system can accommodate 85 MW without transmission upgrades.

The reason the system can accommodate the 85 MW of transfers is that during the times when peak transfers across Midpoint West and Boise East are required (light load, heavy thermal generation in the east), the load in the western and central regions of Idaho is very low. New transmission is not required to serve network load, because network load is far less than Midpoint West/Boise East transmission capacity. Network resource generation east of Midpoint (such as Bridger, Valmy, or wind) will have to be curtailed when transfers exceed network load AND Midpoint West/Boise East transmission capability.

The Midpoint West path can be operated to 1200 MW while Midpoint – Hemingway 500 kV line is at 1500 MW. Between 2005 and 2010, as of the writing of this report, peak transmission requirements across Midpoint West were 672 MW for network load.

4.0 Scope of Transmission Service System Impact Study

This Transmission Service System Impact Study was done and prepared in accordance with Idaho Power Company's Tariff — Transmission Service, to provide an evaluation if the existing transmission system can accommodate the requested transmission service and if necessary determines the required network upgrades to the transmission system to provide the requested transmission service. This study will only be concerned with the capabilities of the Idaho Power system to provide transmission from the generation's POR to the POD of Idaho Power (IPCO).

5.0 Description of Existing Transmission Facilities

For this Transmission Service System Impact Study, the following two internal Idaho Power transmission paths were evaluated to determine if they could accommodate the requested transmission service, and if necessary determine the required network upgrades to provide the transmission service.

The West of Midpoint transmission path is defined as the sum of the flows on the following five lines:

- Midpoint*-Boise Bench (#3) 230 kV
- Midpoint*-Rattlesnake (#2) 230 kV
- King*-MtnAirTp (#1) 230 kV
- Lower Malad*-Mt Home Jct 138 kV
- Upper Salmon*-Mt Home Jct 138 kV

The Boise East transmission path is defined as the sum of the flows on the following seven lines and transformer:

- Boise Bench*-Midpoint (#3) 230 kV
- Boise Bench*-Rattlesnake (#2) 230 kV
- Dram*-King (#1) 230 kV
- Hubbard*-Danskin 230 kV
- Dram*-MtnAirTp 138 kV
- Bowmont*-Swan Falls-Strike 138 kV
- Boise Bench*-Elmore 69 kV
- Hemingway 230/500 kV Transformer

* Indicates the measurement point.

6.0 Existing Transmission Commitments

The methodology used to determine if transmission capacity exists across Midpoint West utilized coincident historical numbers for load and generation.

On an hour-by-hour basis, starting in 2005, Idaho Power generation and load east of Midpoint were off-set to determine the amount of power that was required to cross the Midpoint West path. Firm transmission purchases from the east were also added to this number (87 MW from Jefferson to IPCO, and 7 MW for Boardman generation). This calculated number was then compared, hour-by-hour, to the load in Idaho Powers central and western regions. Taking the minimum of these two values yields the required network resource transmission capacity for that hour. The maximum amount of transmission required across Midpoint West by Idaho Power, for the years between 2005 & 2010 (as of the writing of this report) was calculated to be 672 MW.

Below is a time duration table on how long, as a percentage of the past five years, Midpoint West's required network transmission was above a certain amount:

Midpoint West Network Transmission Required	% of 2005-2010 Hours
>600	1%
>500	13%
>400	34%
>300	56%

Table 1

The 672 MW number does not include PacifiCorp's firm transmission wheeling across Midpoint West, which is estimated at 223 MW. The result of subtracting 223 MW off of the 1200 MW Midpoint West capacity results in 977 MW as the capacity available for network transmission.

Since wind is a variable resource, with only a 30% on average capacity factor, associating one-for-one transmission with a wind project is conservative. Associating one-for-one transmission with many wind projects, totaling hundreds of mega-watts, spread out over a large geographical area may be overly conservative, and this methodology offers a different approach moving forward.

7.0 Description of Power Flow Cases

The WECC 2008-09 LW1A operating case, approved June 27, 2008, was chosen as the power flow base case for the starting point of the studies. This power flow case was modified to represent high east to west transfers across the Idaho transmission system during off-peak conditions and with historical seen south to north transfers on the California Oregon Intertie (COI). Midpoint West/Boise East power flow is limited by the loading on the 1500 MVA Midpoint 500/345 kV transformer in the steady-state with the Midpoint 500 kV series capacitor in the Midpoint-Hemingway 500 kV line half-bypassed. Pre-contingency flow across the Midpoint West transmission path was approximately 1200 MW. Tabulated below in Table 1 are the significant transmission path flows in the Idaho transmission system and on COI for the power flow cases used in this transmission service system impact study. The base case has light load, heavy thermal generation in Utah and Wyoming, and heavy wind generation across most of central Idaho. Added to the case is 120 MW of generation to represent six TSRs ahead of The Request in the queue, and The Request itself. The case was then stressed until Midpoint – Hemingway was approximately 1500 MW.

Power Flow Case	COI	Boise East	West of Midpoint	West of Borah	Idaho to Sierra	Midpoint - Hemingway
Base Case	-1486	-1282	1203	2405	-301	1495

Table 2

8.0 Power Flow Analysis Study Results

This Transmission Service System Impact Study Report for 85 MW is for PURPA Network Resource Service for four 20 MW wind projects and [redacted] collectively called The Request.

Following a single contingency (N-1) on the transmission system, this study assumes no system element should be overloaded above its 30 minute thermal capability. The 30 minute thermal capability of IPC's transmission lines is 115% and for transformers is 110%. IPC's series capacitors are capable of 135% flow for 30 minutes. The assumption of "dispatchability" allows the generator outputs to be lowered to relieve any overloads and lower loadings to 100% or below nominal thermal capabilities (See Acceptability Criteria in Appendix A).

Base Case

N-0 Overloads:

As stated above, pre-contingency loading on Midpoint West was limited to 1200 MW due to 1500 MW loading on the 1500 MVA Midpoint 500/345 kV transformer in the steady-state with the Midpoint 500 kV series capacitor in the Midpoint-Hemingway 500 kV line half-bypassed.

N-1 Overloads:

The loss of the Midpoint – Hemingway 500 kV line with Remedial Action Scheme (RAS) of tripping two Jim Bridger units results in slightly overloading the King – MtnAirTp 230 kV line. Tripping only a single unit, as should be required, overloads the King – MtnAirTp 230 kV line beyond its emergency rating. Tripping of either two Bridger units, or one Bridger unit with sufficient wind tripping will be required to maintain the studied transfer levels.

The loss of the Midpoint – Boise Bench 230 kV line resulted in overloading the King – MtnAirTp 230 kV line to just under 100% of its emergency rating.

N-2 Overloads:

The loss of the Midpoint – Hemingway 500 kV line and the Midpoint – King 230 kV lines with RAS tripping of two Bridger units slightly overloads the King 230/138 kV transformer and the Midpoint series capacitors in the Midpoint – Boise Bench and Midpoint – Rattlesnake 230 kV lines. All overloads are less than their respective emergency ratings.

9.0 Transient Stability Analysis

Transient stability was studied in the Generation Interconnection System Impact Study for the projects requiring transmission service. The results showed no transient stability violations.

10.0 Conclusions

A Transmission System Impact Study was performed evaluating the performance of the IPC transmission system with 85 MW of additional power transfer from MDSK (POR) to IPCO (POD). Based on the locations of the projects, upgrades are not required to transfer 85 MW from MDSK to IPCO.

The reason the system can accommodate the 85 MW of transfers is that during the times when peak transfers across Midpoint West and Boise East are required (light load, heavy thermal generation in the east), the load in the western and central regions of Idaho is very low. New transmission is not required to serve network load, because network load is far less than Midpoint West/Boise East transmission capacity. Network resource generation east of Midpoint (such as Bridger, Valmy, or wind) will have to be curtailed when transfers exceed network load AND Midpoint West/Boise East transmission capability.

APPENDIX A

1.0 Method of Study

The study methodology inserts the proposed generators up to the maximum requested output of 85 MW into the selected WECC power flow case and then, using the GE PSLF power flow program, examines the impacts of the new resource on Idaho Power's transmission system (lines, transformers, etc.) within the Study area under various operating/outage scenarios. The WECC and Idaho Power reliability criteria and Idaho Power operating procedures were used to determine the acceptability of the alternatives considered. The WECC case is a recent case modified to simulate stressed but reasonable pre-contingency energy transfers utilizing the IPC system.

2.0 Acceptability Criteria

The following acceptability criteria were used in the power flow analysis to determine the acceptability of the alternatives:

Loadings on transmission lines and transformers should not exceed **100%** of their 30 minute emergency rating (approximately 115% of continuous rating for transmission lines and 110% of continuous rating for transformers), immediately following any N-I outage. Loading on the Midpoint 230 kV series capacitors should not exceed **100%** of their 30 minute emergency rating (135% of the continuous rating), immediately following any N-1 outage. These loadings levels of 115% on transmission lines, 110% on transformers, and 135% on Midpoint series capacitors correspond to IPC's 30 minute emergency equipment ratings. Any loadings immediately following an N-I outage, less than the 30 minute emergency rating is acceptable.

Loadings which are less than the 30 minute emergency equipment ratings, but greater than the equipment continuous ratings, Must be reduced to the Continuous ratings by generation curtailments, re-dispatch, or some other operating procedure. Any remedial action schemes (RAS) or other transmission switching, must be judged to be reasonable before the alternatives performance can be deemed acceptable.

The continuous rating of equipment is assumed to be the normal thermal rating of the equipment. This rating will be as determined by the manufacturer of the equipment or as determined by Idaho Power. Less than or equal to 100% of continuous rating (or transmission lines and transformers is acceptable. Less than or equal to 110% of continuous rating for the Midpoint 230 kV series capacitors is acceptable.

Transmission voltages, under normal operating conditions, are maintained within plus or minus 5% (0.05 per unit) of nominal. Therefore, voltages greater than or equal to 0.95 pu voltage and less than or equal to 1.05 pu voltage are acceptable.

The stable operation of the transmission system requires an adequate supply of volt-amperes reactive (VARs) to maintain a stable voltage profile under both steady-state and dynamic system conditions. An inadequate supply of VARs will result in voltage decay or even collapse under the worst conditions. Idaho Power designs its system to integrate Network Resources at full capability during specified outage conditions.

Equipment/line/path ratings used will be those that are in use at the time of the study or that are represented by IPC upgrade projects that are either currently under construction or whose budgets have been approved for construction in the near future. All other potential future ratings are outside the scope of this study. Future transmission changes may, however, affect current facility ratings used in the study.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 28

GENERATOR INTERCONNECTION
SYSTEM IMPACT STUDY

for integration of the proposed

IPC Project Q#325, & #327

in

TWIN FALLS COUNTY, IDAHO

to the

IDAHO POWER COMPANY ELECTRICAL SYSTEM

for

the

INTERCONNECTION CUSTOMER

FINAL REPORT

December 29, 2010

JLE

1.0 Introduction

The Interconnection Customer has contracted with Idaho Power Company (IPC) to perform a System Impact Study (SIS) for the integration of IPC Generation Interconnection Project Queue #325 & 327, a 20 MW wind generation project and 200 MW wind generation project respectively (both to be further referred to as The Projects). The Projects are located in IPCs southern service territory in Twin Falls County, Idaho. The new generation will be interconnected at a new substation (Station325) under the Midpoint – Humboldt 345 kV transmission line. The point of interconnection to IPC will be the customer side of the generator interconnection package.

This report documents the basis for and the results of this SIS for the proposed projects. It describes the proposed projects, the impact of associated projects and results of all work in the areas of concern.

2.0 Summary

This SIS looks at two items: (1) Local interconnection requirements for the interconnection of The Projects to the Midpoint – Humboldt 345 kV line, and (2) Transient stability of The Projects.

IPC Transmission Network Upgrades may be necessary if firm transmission is required to deliver The Projects generation from the point of interconnection (point of receipt) to a point of delivery. A transmission service request (TSR) will be required to secure transmission rights on the IPC system, either through latent capacity, or Network Upgrades. Either the interconnection customer, or the merchant purchasing the generation from the interconnection customer, will have to make this TSR. Transmission rights are beyond the scope of this Generation Interconnection System Impact Study. **IPC Transmission Network Upgrade costs are not included in this GI SIS, however, costs could be sizeable.**

Local Interconnection Requirements

Connecting The Project to the Midpoint – Humboldt 345 kV line will require the following:

1) A new 345/138 kV class substation at the project location.

Capacity Benefit Margin problems exist if the entire 220 MW of wind generation is sold to IPC with only a single connection to the 345 kV system. IPC has no knowledge or where this generation is planned to be sold; this problem will be addressed in an associated Transmission Service Request.

Total Estimated Cost: $3,980,000

More detail is located in Section 5.

The generation step up transformer will be connected as a solidly grounded wye on the high (transmission) side.

Transient Stability of The Projects

Select outages were studied using GE PSLF software. The stability analysis performed demonstrated that, for the initial conditions and outages examined, the system was stable and damped and that none of the results exceeded the stated voltage or frequency stability criteria on the system external to The Projects. IPC does not anticipate that any additional transmission system modifications will have to be made to arrest or otherwise manage any stability issues as a result of introducing the proposed new resource to the transmission system.

3.0 Scope of Interconnection System Impact Study

The Interconnection System Impact Study was done and prepared in accordance with Idaho Power Company Standard Generator Interconnection Procedures, to provide a detailed evaluation of the interconnection of the proposed generating project to the Idaho Power system. As listed in Section 5.0 of the Interconnection System Impact Study agreement, the Interconnection System Impact Study report provides the following information:

- identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;
- identification of any thermal overload or voltage limit violations resulting from the interconnection;
- identification of any instability or inadequately damped response to system disturbances resulting from the interconnection; and
- description and non-binding, good faith estimated cost of facilities required to interconnect the Large Generating Facility to the Transmission System and to address the identified short circuit, stability, and power flow issues.

All other proposed Generation projects prior to this project in the Generator Interconnect queue were considered in this study. A current list of these projects can be found on the Idaho Power web site, **http://www.oatioasis.com/ipco/index.html**.

4.0 Description of Proposed Generating Project

The Projects consist of 220 MW of wind generation. ProjectQ#325 is a 20 MW project and ProjectQ#327 is a 200 MW project.

At a new station, under the Midpoint – Humboldt 345 kV line, the generation will interconnect to the IPC system.

The proposed in-service date for this project is December, 2011.

5.0 Local Area 345 kV Facility Upgrades

5.1 Transmission Line Facilities

Connecting The Project to the Midpoint – Humboldt 345 kV line will require the following:

1) A new 345/138 kV class substation at the project location.

The new 345/138 kV class substation will consist of at least one 345 kV line terminal and a customer owned 345/34.5 kV transformer. The Projects will be added to the Midpoint – Humboldt 345 kV line as a tap. The fact that the line currently utilizes single-pole tripping is not expected to be a problem. The point of interconnection will be the 345 kV breaker on the high side of the 345/34.5 kV transformer.

The IPC – Sierra transmission path's rating limits the south to north transfers across Midpoint – Humboldt to 360 MW. Existing IPC generation utilizes 262.5 MW of this transfer capability, leaving 97.5 MW of capacity available for firm transmission northbound (which may or may not be available to The Project). The 360 MW transfer limit could likely be increased by going through the WECC rating process.

IPCs Capacity Benefit Margin (CBM) is a substantial problem if the entire 220 MW output of The Projects is sold to IPC. IPC holds 330 MW of firm transmission capacity in reserve for the worst case generation loss on the system. With the addition of 220 MW to the Midpoint – Humboldt 345 kV line, 262.5 MW (IPC Existing) + 220 MW (The Project) = 482.5 MW could be either tripped or stranded to the Sierra system with the loss of the Midpoint – Humboldt 345 kV line, creating a new worst-case situation.

NV Energy owns a major share in the Midpoint – Humboldt 345 kV line. These interconnection projects will have to be coordinated between the interconnection customer, Idaho Power, NV Energy, and other planned projects connecting to the Midpoint – Humboldt 345 kV line. Coordination is required to ensure system integrity.

5.2 Substation Facilities

Connecting The Project to the Midpoint – Humboldt 345 kV line will require the following:

1) A new 345/138 kV class substation at the project location.

The new 345/138 kV class substation will consist of at least one 345 kV line terminal and a customer owned 345/34.5 kV transformer. The Projects will be added to the Midpoint – Humboldt 345 kV line as a tap. The fact that the line currently utilizes single-pole tripping is not expected to be a problem. The point of interconnection will be the 345 kV breaker on the high side of the 345/34.5 kV transformer.

The generation step up transformer will be connected as a solidly grounded wye on the high (transmission) side.

Studies indicate that there is adequate short circuit interrupting capability on breakers in the area for the addition of this generation project. Protective relaying and communications upgrades may be required in adjacent substations.

6.0 Operational Considerations

This study assumes that the generators at the three projects will be Type 3 machines, capable of +/- 0.95 operation. The Projects should be capable of +/- 0.95 power factor operation, as measured at the interconnection point, for all MW production levels from zero MW output to full rated MW output. The interconnection customer will be provided a voltage schedule from Idaho Power Grid Operations prior to Commercial Operation of the project. These projects cannot interconnect without +/- 0.95 power factor capability.

Idaho Power and Nevada Power will have to modify the loss calculations on the Midpoint – Humboldt – Coyote – Valmy 345 kV line with the addition of The Project.

If The Projects use units other than Type 3 wind turbine generators, the interconnection customer must work with IPC to determine the amount of switched capacitors/reactors and possible SVC (dynamic VAR) type devices required to interconnect the project.

7.0 Network Integration of The Projects

Depending on where The Projects wish to sell their generation, Network Upgrades may be required to transmit the power from the point of receipt to the point of delivery. A transmission service request will be required to secure transmission rights on the IPC system. Generation Interconnection System Impact Studies cannot allocate transmission service.

8.0 Transient Stability of The Projects

Select outages were studied using GE PSLF software. The stability analysis performed demonstrated that, for the initial conditions and outages examined, the system was stable and damped and that none of the results exceeded the stated voltage or frequency stability criteria on the system external to The Projects. IPC does not anticipate that any additional transmission system modifications will have to be made to arrest or otherwise manage any stability issues as a result of introducing the proposed new resource to the transmission system.

9.0 Description and Cost Estimate of Required Facility Upgrades

The following table lists cost estimates of the directly assignable costs for the upgrades needed to accommodate the proposed project. Allowance for funds used during construction (AFUDC) has not been included in the cost estimates since it is assumed that IPC will be provided up-front funding by the Project. No attempt has been made in this study to assign network upgrade costs and not all of the estimated facility costs are necessarily the responsibility of the Project. These are cost estimates only and final charges to the customer will be based on the actual construction costs incurred. Note that this estimate does not include the cost of the customer's equipment.

Table 1. Estimated Costs for Required Idaho Power Local Area Upgrades

Description	**Cost**
Project Substation Site Prep, General Facilities	$800,000
One 345 kV terminal	$1,000,000
Control Area Metering Relocation	$400,000
Network Communications	$750,000
Contingencies & Overheads	$1,030,000
TOTAL	**$3,980,000**

Costs for potential Network Upgrades are not included, but could be sizable.

10.0 Conclusions

The requested interconnection of ProjectQ#325 & #327 to Idaho Power's system was studied. The result of this work indicates that the local area Idaho Power transmission system can be upgraded to support this project. The estimated costs of the modifications required, excluding potential network transmission upgrades, are listed in Section 9.0 of this report. These are estimated costs only and final charges to the customer will be based on the actual construction costs incurred.

Next, a facility study will be required to look at the requirements from a construction standpoint. The Facility Study will yield a much more detailed and thorough cost estimate.

APPENDIX A

A-1.0 Method of Study

The System Impact Study inserts the Project up to the maximum requested injection into the selected Western Electric Coordinating Council (WECC) power flow case and then, using GE's Positive Sequence Load Flow (PSLF) analysis tools or Power World Simulator, examines the impacts of the new resource on Idaho Power's system (lines, transformers, etc.) within the study area under various operating/outage scenarios. The WECC and Idaho Power reliability criteria and Idaho Power operating procedures were used to determine the acceptability of the configurations considered. The WECC case is a recent case modified to simulate stressed but reasonable pre-contingency energy transfers utilizing the IPC system.

A-2.0 Acceptability Criteria

The following acceptability criteria were used in the power flow analysis to determine under which system configuration modifications may be required:

> The continuous rating of equipment is assumed to be the normal thermal rating of the equipment. This rating will be as determined by the manufacturer of the equipment or as determined by Idaho Power. Less than or equal to 100% of continuous rating is acceptable.
>
> Idaho Power's Voltage Operating Guidelines were used to determine voltage requirements on the system. This states, in part, that distribution voltages, under normal operating conditions, are to be maintained within plus or minus 5% (0.05 per unit) of nominal everywhere on the feeder. Therefore, voltages greater than or equal to 0.95 pu voltage and less than or equal to 1.05 pu voltage are acceptable.
>
> All customer generation must meet IEEE 519 and ANSI C84.1 Standards.
>
> All other applicable national and Idaho Power standards and prudent utility practices were used to determine the acceptability of the configurations considered.
>
> The stable operation of the system requires an adequate supply of volt-amperes reactive (VARs) to maintain a stable voltage profile under both steady-state and dynamic system conditions. An inadequate supply of VARs will result in voltage decay or even collapse under the worst conditions.

Equipment/line/path ratings used will be those that are in use at the time of the study or that are represented by IPC upgrade projects that are either currently under construction or whose budgets have been approved for construction in the near future. All other potential future ratings are outside the scope of this study. Future transmission changes may, however, affect current facility ratings used in the study.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 29

GENERATOR INTERCONNECTION
SYSTEM IMPACT STUDY

for integration of the proposed

IPC Project Q#322, #323, & #324

in

TWIN FALLS COUNTY, IDAHO

to the

IDAHO POWER COMPANY ELECTRICAL SYSTEM

for

the

INTERCONNECTION CUSTOMER

FINAL REPORT

January 4, 2010

OFFICIAL USE ONLY

DO NOT DUPLICATE, DISTRIBUTE, PUBLISH OR SHARE

This report contains Idaho Power Company Critical Energy Infrastructure Information (CEII). Distribution of this report must be limited to parties that have entered into a non-disclosure agreement with Idaho Power Company and have a need to know.

JLE

1.0 Introduction

The Interconnection Customer has contracted with Idaho Power Company (IPC) to perform a System Impact Study (SIS) for the integration of IPC Generation Interconnection Project Queue #322, 323, & 324, three 20 MW wind projects (all to be further referred to as The Projects). The Projects are located in IPCs southern service territory in Twin Falls County, Idaho. The new generation will be connected to the IPC 138 kV system at a new station located under the Upper Salmon – Wells 138 kV line. The point of interconnection to IPC will be the customer side of the generator interconnection package.

This report documents the basis for and the results of this SIS for the proposed three 20 MW wind generation projects. It describes the proposed projects, the impact of associated projects and results of all work in the areas of concern.

2.0 Summary

This SIS looks at two items: (1) Local interconnection requirements for the interconnection of The Projects to IPCs Upper Salmon – Wells 138 kV line, and (2) Transient stability of The Projects.

IPC Transmission Network Upgrades may be necessary if firm transmission is required to deliver The Projects generation from the point of interconnection (point of receipt) to a point of delivery. A transmission service request (TSR) will be required to secure transmission rights on the IPC system, either through latent capacity, or Network Upgrades. Either the interconnection customer, or the merchant purchasing the generation from the interconnection customer, will have to make this TSR. Transmission rights are beyond the scope of this Generation Interconnection System Impact Study. **IPC Transmission Network Upgrade costs are not included in this GI SIS, however, costs could be sizeable.**

Local Interconnection Requirements

If firm transmission is required (as it will be if this is a PURPA project), the Upper Salmon – Blue Gulch 138 kV line (10.2 miles) will have to be rebuilt in order to integrate the first 20 MW (ProjectQ#322) of The Project. The first 20 MW can be integrated with 10 MW of firm transmission and 10 MW of non-firm transmission without the rebuild. This integration will require the addition of an overload mitigation scheme at the point of interconnection. Transmission is only "firm" as far as Upper Salmon; a TSR will be required to secure transmission rights on the remaining IPC system.

In order to integrate the second 20 MW (ProjectQ#323), 40 MW total, the Upper Salmon – Blue Gulch line must be rebuilt. An overload mitigation scheme is not required, and will offer no benefit.

In order to integrate the last 20 MW (ProjectQ#324), 60 MW total, if firm transmission is required (as it will be if this is a PURPA project), the entire 138 kV transmission line from the point of interconnection to Upper Salmon will have to be rebuilt (~46 miles). The Projects can be integrated with 50 MW of firm transmission and 10 MW of non-firm transmission with the 10.2 mile Upper Salmon – Blue Gulch 138 kV rebuild and an overload mitigation scheme. Transmission is only "firm" as far as Upper Salmon; a TSR will be required to secure transmission rights on the remaining IPC system.

For integration of 50 MW or more, if firm transmission is required, the Upper Salmon – King 138 kV line will have to be rebuilt (~5 miles). Loss of a 138 kV line on the IPC system can overload this line beyond its emergency rating. If firm transmission is not required, an overload mitigation scheme can solve this problem.

Integration of any of all of The Projects requires the addition of a new substation. IPCs section of the new substation will consist of at least one 138 kV breaker and potentially a building to house protection equipment including the generation interconnection package. The point of interconnection will be on the customer side of the generator interconnection package.

The generation step up transformer will be connected as a solidly grounded wye on the high (transmission) side.

Transient Stability of The Projects

Select outages were studied using GE PSLF software. The stability analysis performed demonstrated that, for the initial conditions and outages examined, the system was stable and damped and that none of the results exceeded the stated voltage or frequency stability criteria on the system external to The Projects. IPC does not anticipate that any additional transmission system modifications will have to be made to arrest or otherwise manage any stability issues as a result of introducing the proposed new resource to the transmission system.

3.0 Scope of Interconnection System Impact Study

The Interconnection System Impact Study was done and prepared in accordance with Idaho Power Company Standard Generator Interconnection Procedures, to provide a detailed evaluation of the interconnection of the proposed generating project to the Idaho Power system. As listed in Section 5.0 of the Interconnection System Impact Study agreement, the Interconnection System Impact Study report provides the following information:

- identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;
- identification of any thermal overload or voltage limit violations resulting from the interconnection;
- identification of any instability or inadequately damped response to system disturbances resulting from the interconnection; and
- description and non-binding, good faith estimated cost of facilities required to interconnect the Large Generating Facility to the Transmission System and to address the identified short circuit, stability, and power flow issues.

All other proposed Generation projects prior to this project in the Generator Interconnect queue were considered in this study. A current list of these projects can be found on the Idaho Power web site, **http://www.oatioasis.com/ipco/index.html**.

4.0 Description of Proposed Generating Project

The Projects consist of three 20 MW wind generation projects, ProjectQ#322, #323, and #324.

At a new station, under the Upper Salmon – Wells 138 kV line, the generation will interconnect to the IPC system.

The proposed in-service date for this project is December 2011.

5.0 Local Area 138 kV Facility Upgrades

5.1 Transmission Line Facilities

Idaho Power's Upper Salmon – Wells 138 kV transmission line serves the interconnection area. Due to the age and lack of growth in the area, the Upper Salmon – Wells 138 kV line has deteriorated and upgrades have not been carried out. Due to this, the rating of the line has been recommended at 50 MVA. Considering other projects ahead of The Projects in the IPC Generation Interconnection queue, there is not transmission capacity available on this line to serve The Projects.

There is capacity for one 20 MW project, without extensive upgrades, if load south of the point of interconnection always remains online (load always exceeds 10 MW). If load at Wells were to trip offline, and generation on the Upper Salmon – Wells 138 kV line was peaking, the Upper Salmon – Blue Gulch line would overload beyond the 50 MW limit.

If firm transmission is required (as it will be if this is a PURPA project), the Upper Salmon – Blue Gulch 138 kV line (10.2 miles) will have to be rebuilt in order to integrate the first 20 MW (ProjectQ#322) of The Project. The first 20 MW can be integrated with 10 MW of firm transmission and 10 MW of non-firm transmission without the rebuild. This integration will require the addition of an overload mitigation scheme at the point of interconnection; transmission flow will be limited to 10 MW north (20 MW generation minus 10 MW assumed load south) from the point of interconnection to Blue Gulch. Transmission is only firm as far as Upper Salmon; a TSR will be required to secure transmission rights on the remaining IPC system.

In order to integrate the second 20 MW (ProjectQ#323), 40 MW total, the Upper Salmon – Blue Gulch line must be rebuilt. An overload mitigation scheme is not required, and will offer no benefit.

In order to integrate the last 20 MW (ProjectQ#324), 60 MW total, if firm transmission is required (as it will be if this is a PURPA project), the entire 138 kV transmission line from the point of interconnection to Upper Salmon will have to be rebuilt (~46 miles). The Projects can be integrated with 50 MW of firm transmission and 10 MW of non-firm transmission with the 10.2 mile Upper Salmon – Blue Gulch 138 kV rebuild and an overload mitigation scheme. Transmission is only firm as far as Upper Salmon; a TSR will be required to secure transmission rights on the remaining IPC system.

For integration of 50 MW or more, if firm transmission is required, the Upper Salmon – King 138 kV line will have to be rebuilt (~5 miles). This line overloads beyond its emergency rating for loss of the Mountain Home Junction – Danskin 138 kV line. If firm transmission is not required, an overload mitigation scheme can solve this problem.

5.2 Substation Facilities

The Projects will be interconnected at a new 138 kV class substation. IPCs section of the new substation will consist of at least one 138 kV breaker and potentially a building to house protection equipment including the generation interconnection package. The point of interconnection will be on the customer side of the generator interconnection package.

The generation step up transformer will be connected as a solidly grounded wye on the high (transmission) side.

Studies indicate that there is adequate short circuit interrupting capability on breakers in the area for the addition of this generation project. Protective relaying and communications upgrades may be required in adjacent substations.

6.0 Operational Considerations

Connecting The Projects to the Upper Salmon – Wells 138 kV line offers some major problems in terms of voltage control. Without absorbing a significant amount of VARs (at least 13 MVARs), the voltage at the point of interconnection exceeds 1.05 per unit. This study assumes that the generators at the three projects will be Type 3 machines, capable of +/- 0.95 operation. The Projects should be capable of +/- 0.95 power factor operation, as measured at the interconnection point, for all MW production levels from zero MW output to full rated MW output. The interconnection customer will be provided a voltage schedule from Idaho Power Grid Operations prior to Commercial Operation of the project. These projects cannot interconnect without +/- 0.95 power factor capability.

If The Projects use units other than Type 3 wind turbine generators, the interconnection customer must work with IPC to determine the amount of switched capacitors/reactors and possible SVC (dynamic VAR) type devices required to interconnect the project and mitigate high voltage concerns.

7.0 Network Integration of The Projects

Depending on where The Project wishes to sell their generation, Network Upgrades may be required to transmit the power from the point of receipt to the point of delivery. A transmission service request will be required to secure transmission rights on the IPC system. Generation Interconnection System Impact Studies cannot allocate transmission service.

In order to utilize the generation on the IPC system, The Projects' generation will be transmitted to IPCs growing Treasure Valley (Boise) area. Midpoint West, an internal IPC transmission path, is a bottleneck between The Projects & Boise. In order to increase Midpoint West an additional 60 MW, a new 230 kV transmission line between Midpoint and the Treasure Valley would be required. At this point, IPC is not considering options for new 230 kV west out of Midpoint as network upgrades. IPC is in the early stages of a 500 kV transmission project known as Gateway West, which will eventually connect Midpoint to the Treasure Valley. Gateway West will increase the transmission capacity of the Midpoint West cut-plane by well over 60 MW, however this project is not scheduled for completion until sometime after 2014. Between The Projects' in-service date and completion of the Midpoint – Treasure Valley portion of the Gateway West project, The Projects would have to operate as a conditional firm resource, available to be tripped offline if there are problems on the system. A transmission service request will be required to secure transmission rights on the IPC system, and this new transmission project.

8.0 Transient Stability of The Projects

Select outages were studied using GE PSLF software. The stability analysis performed demonstrated that, for the initial conditions and outages examined, the system was stable and damped and that none of the results exceeded the stated voltage or frequency stability criteria on the system external to The Projects. IPC does not anticipate that any additional transmission system modifications will have to be made to arrest or otherwise manage any stability issues as a result of introducing the proposed new resource to the transmission system.

9.0 Description and Cost Estimate of Required Facility Upgrades

The following tables lists cost estimates of the directly assignable costs for the upgrades needed to accommodate the proposed project. Allowance for funds used during construction (AFUDC) has not been included in the cost estimates since it is assumed that IPC will be provided up-front funding by the Project. No attempt has been made in this study to assign network upgrade costs and not all of the estimated facility costs are necessarily the responsibility of the Project. These are cost estimates only and final charges to the customer will be based on the actual construction costs incurred. Note that this estimate does not include the cost of the customer's equipment.

Table 1. Estimated costs assuming the projects are PURPA, Network Resource

Description	Cost
46 mile 138 kV line	$23,000,000
4 mile 138 kV line	$2,000,000
Generation Interconnection Package	$800,000
Contingencies & Overheads	$5,740,000
Total Estimated Cost	**$31,540,000**

Table 2. Estimated costs if projects are curtailable, Energy Resource

Description	Cost
10.2 mile 138 kV line	$5,000,000
Generation Interconnection Package	$800,000
Contingencies & Overheads	$1,290,000
Total Estimated Cost	**$7,090,000**

Costs for potential Network Upgrades are not included, but could be sizable.

10.0 Conclusions

The requested interconnection of ProjectQ#322, #323, & #324 to Idaho Power's system was studied. The result of this work indicates that the local area Idaho Power transmission system can be upgraded to support this project. The estimated costs of the modifications required, excluding potential network transmission upgrades, are listed in Section 9.0 of this report. These are estimated costs only and final charges to the customer will be based on the actual construction costs incurred.

Next, a facility study will be required to look at the requirements from a construction standpoint. The Facility Study will yield a much more detailed and thorough cost estimate.

APPENDIX A

A-1.0 Method of Study

The System Impact Study inserts the Project up to the maximum requested injection into the selected Western Electric Coordinating Council (WECC) power flow case and then, using GE's Positive Sequence Load Flow (PSLF) analysis tools or Power World Simulator, examines the impacts of the new resource on Idaho Power's system (lines, transformers, etc.) within the study area under various operating/outage scenarios. The WECC and Idaho Power reliability criteria and Idaho Power operating procedures were used to determine the acceptability of the configurations considered. The WECC case is a recent case modified to simulate stressed but reasonable pre-contingency energy transfers utilizing the IPC system.

A-2.0 Acceptability Criteria

The following acceptability criteria were used in the power flow analysis to determine under which system configuration modifications may be required:

> The continuous rating of equipment is assumed to be the normal thermal rating of the equipment. This rating will be as determined by the manufacturer of the equipment or as determined by Idaho Power. Less than or equal to 100% of continuous rating is acceptable.
>
> Idaho Power's Voltage Operating Guidelines were used to determine voltage requirements on the system. This states, in part, that distribution voltages, under normal operating conditions, are to be maintained within plus or minus 5% (0.05 per unit) of nominal everywhere on the feeder. Therefore, voltages greater than or equal to 0.95 pu voltage and less than or equal to 1.05 pu voltage are acceptable.
>
> All customer generation must meet IEEE 519 and ANSI C84.1 Standards.
>
> All other applicable national and Idaho Power standards and prudent utility practices were used to determine the acceptability of the configurations considered.
>
> The stable operation of the system requires an adequate supply of volt-amperes reactive (VARs) to maintain a stable voltage profile under both steady-state and dynamic system conditions. An inadequate supply of VARs will result in voltage decay or even collapse under the worst conditions.

Equipment/line/path ratings used will be those that are in use at the time of the study or that are represented by IPC upgrade projects that are either currently under construction or whose budgets have been approved for construction in the near future. All other potential future ratings are outside the scope of this study. Future transmission changes may, however, affect current facility ratings used in the study.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 30

IDAHO POWER
An IDACORP Company

January 13, 2011

Collin Rudeen
Exergy Development Group of Idaho
802 W Bannock, Suite 1200
Boise, ID 83702

Re: Project # 322, 323, 324 – Rogerson Flats, Cottonwood, & Deep Creek Wind Projects

Dear Collin:

Enclosed is the Final System Impact Study Report (SISR) for the above-referenced projects. Also enclosed are two copies of the Facility Study Agreement (FSA) to begin the next phase of the project. The Facility Study Agreement (FSA) describes the design phase of the project, the responsibilities and obligations of both parties, and the work schedules required. To proceed with this application, Idaho Power must receive your executed FSA and the required deposit in order to remain in the Generator Interconnection queue. The deposit under this FSA is $100,000 based on the estimated engineering costs.

If you wish to proceed, please complete Attachment A & B, sign both copies and submit them along with the deposit to Idaho Power Company, attn: Rowena Bishop by March 1, 2011 otherwise these applications will be deemed withdrawn. Please contact me if you have any questions.

Sincerely,

Marc Patt

Marc Patterson
T&D Engineering Leader
208.388.5712

Encl: Final System Impact Study Report
Two Facility Study Agreements for signature

Cc: Rowena Bishop/IPC
Ed Kosydar/IPC

Facilities Study Agreement

THIS AGREEMENT is made and entered into this _____day of______________ 2011 by and between ____________________________________, a ________________________ organized and existing under the laws of the State of ____________________, ("Interconnection Customer,") and Idaho Power Company, a Corporation existing under the laws of the State of Idaho ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer on March 10, and March 15, 2010; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a system impact study and provided the results of said study to the Interconnection Customer; and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a facilities study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the system impact study in accordance with Good Utility Practice to physically and electrically connect the Small Generating Facility with the Transmission Provider's Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause a facilities study consistent with the standard Small Generator Interconnection Procedures to be performed in accordance with the Open Access Transmission Tariff.

3.0 The scope of the facilities study shall be subject to data provided in Attachment A to this Agreement.

4.0 The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s).

The facilities study shall also identify (1) the electrical switching configuration of the equipment, including, without limitation, transformer, switchgear, meters, and other station equipment, (2) the nature and estimated cost of the Transmission Provider's

Interconnection Facilities and Upgrades necessary to accomplish the interconnection, and (3) an estimate of the time required to complete the construction and installation of such facilities.

5.0 The Transmission Provider may propose to group facilities required for more than one Interconnection Customer in order to minimize facilities costs through economies of scale, but any Interconnection Customer may require the installation of facilities required for its own Small Generating Facility if it is willing to pay the costs of those facilities.

6.0 A deposit of $100,000.00 is due upon execution of this agreement by the Interconnection customer.

7.0 In cases where Upgrades are required, the facilities study must be completed within 45 Business Days of the receipt of this Agreement. In cases where no Upgrades are necessary, and the required facilities are limited to Interconnection Facilities, the facilities study must be completed within 30 Business Days.

8.0 Once the facilities study is completed, a facilities study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the facilities study must be completed and the facilities study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct a facilities study.

9.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

10.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

Transmission Provider:
Idaho Power Company - Delivery

Signed: ______________________________

Printed Name: ________________________

Title: ________________________________

Date: ________________________________

Interconnection Customer:

____

Signed: ______________________________

Printed Name: ________________________

Title: ________________________________

Date: ________________________________

Attachment A to
Facilities Study Agreement

Data to Be Provided by the Interconnection Customer With the Facilities Study Agreement

1. Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

   On the one-line diagram, indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

   On the one-line diagram, indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

2. One set of metering is required for each generation connection to the new ring bus or existing Transmission Provider station. Number of generation connections:

   ____

3. Will an alternate source of auxiliary power be available during CT/PT maintenance? Yes ______ No ______

4. Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? Yes ______ No _____
   (Please indicate on the one-line diagram).

5. What type of control system or PLC will be located at the Small Generating Facility?

   ____

   ____

6. What protocol does the control system or PLC use?

   ____

   ____

7. Please provide a 7.5-minute quadrangle map of the site. Indicate the plant, station, transmission line, and property lines.

8. Physical dimensions of the proposed interconnection station:

____

9. Bus length from generation to interconnection station:

____

10. Line length from interconnection station to Transmission Provider's Transmission System.

____

11. Tower number observed in the field. (Painted on tower leg)*:

____

12. Number of third party easements required for transmission lines*:

____

* To be completed in coordination with Transmission Provider.

13. Is the Small Generating Facility located in Transmission Provider's service area?

Yes ______ No ______ If No, please provide name of local provider:

____

14. Please provide the following proposed schedule dates:

Begin Construction	Date: ______________________
Generator Step-Up Transformers Receive Back Feed Power	Date: ______________________
Generation Testing	Date: ______________________
Commercial Operation	Date: ______________________

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 31

IDAHO POWER®
An IDACORP Company

January 11, 2011

Collin Rudeen
Exergy Development Group of Idaho
802 W Bannock Suite 1200
Boise, ID 83702

Re: Salmon Creek GI 325 and Jack Ranch Wind GI 327

Dear Collin:

Enclosed is the Final System Impact Study Report (SISR) for the above-referenced projects.

Also enclosed are two copies of the Standard Large Generator Facility Study Agreement (FSA) to begin the next phase of the project. The FSA describes the design phase of the project, the responsibilities and obligations of both parties, and the work schedules required. To proceed with this application, Idaho Power must receive your executed FSA and the required deposit in order to remain in the Generator Interconnection queue. The deposit under this FSA is $100,000 based on the estimated engineering costs.

If you wish to proceed, please complete Attachment A & B, sign both copies and submit them along with the deposit to Idaho Power Company, attn: Rowena Bishop by February 11, 2011 otherwise your application will be deemed withdrawn. Please contact me if you have any questions.

Sincerely,

Orlando Ciniglio
Engineering Leader, System Planning
208.388.2248

Encl: Final System Impact Study Report
Two Facility Study Agreements

Cc: Rowena Bishop/IPC
Ed Kosydar/IPC

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 32

INTERCONNECTION FACILITIES STUDY AGREEMENT

THIS AGREEMENT is made and entered into this 11th day of February, 2011 by and between ENERGY DEVELOPMENT GROUP OF IDAHO, a LLC organized and existing under the laws of the State of IDAHO, ("Interconnection Customer,") and Idaho Power Company, a Corporation existing under the laws of the State of Idaho, ("Transmission Provider "). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request(s) submitted by Interconnection Customer dated March 15, 2010 ; and

WHEREAS, Interconnection Customer desires to interconnect the Large Generating Facility with the Transmission System;

WHEREAS, Transmission Provider has completed an Interconnection System Impact Study (the "System Impact Study") and provided the results of said study to Interconnection Customer; and

WHEREAS, Interconnection Customer has requested Transmission Provider to perform an Interconnection Facilities Study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Large Generating Facility to the Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved LGIP.

2.0 Interconnection Customer elects and Transmission Provider shall cause an Interconnection Facilities Study consistent with Section 8.0 of this LGIP to be performed in accordance with the Tariff.

3.0 The scope of the Interconnection Facilities Study shall be subject to the assumptions set forth in Attachment A and the data provided in Attachment B to this Agreement.

4.0 The Interconnection Facilities Study report (i) shall provide a description, estimated cost of (consistent with Attachment A), schedule for required facilities to interconnect the Large Generating Facility to the Transmission System and (ii) shall address the short circuit, instability, and power flow issues identified in the Interconnection System Impact Study.

5.0 Interconnection Customer shall provide a deposit of $100,000 for the performance of the Interconnection Facilities Study. The time for completion of the Interconnection Facilities Study is specified in Attachment A.

Transmission Provider shall invoice Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Facilities Study each month. Interconnection Customer shall pay invoiced amounts within thirty (30) Calendar Days of receipt of invoice. Transmission Provider shall continue to hold the amounts on deposit until settlement of the final invoice.

6.0 Effective Date, Duration and Termination. This Agreement becomes effective upon execution by all Parties and shall continue until the work required by the Agreement is completed; provided, however, the Interconnection Customer may terminate this Agreement at any time after providing written notice. In addition, if Interconnecting Customer withdraws its application for interconnection, this Agreement shall terminate effective with the date the application for interconnection is withdrawn.

7.0 No Obligation to Complete Generating Facility. Nothing in this Agreement obligates Interconnection Customer to continue or complete development of the Large Generating Facility or enter into a Large Generator Interconnection Agreement ("LGIA"). A binding agreement and commitment with respect to interconnecting the Large Generating Facility to the Transmission System will only occur upon the execution of an LGIA by Transmission Provider and Interconnection Customer.

8.0 Relationship of the Parties. This Agreement is intended to create an independent contractor relationship between the Parties. It is not to be construed as constituting the Parties as partners, as creating a joint venture, or as creating any other form of legal association or arrangement which would impose liability upon a Party for the act or omission of the other Party.

Transmission Provider shall be responsible for performance and cost of work specified in Attachment A; provided however, that such work shall be performed in accordance with and subject to, Interconnection Customer's right to final review and acceptance, which shall not unreasonably be withheld.

9.0 Standard of Care and Remedies. If any of Transmission Provider's work under this Agreement does not comply with Good Utility Practice including standard design requirements specified in the NERC Facility Connection Requirements, dated January 19, 2006, Transmission Provider will, upon written notice from

Interconnection Customer, promptly re-perform the work at Transmission Provider's sole cost.

In no event will Transmission Provider or Interconnecting Customer or any of their respective agents, employees, officers, directors, affiliates or representatives be liable for incidental, special, punitive or consequential damages including but not limited to lost profits, even if the Parties have been advised of the possibility of such damages. Interconnecting Customer agrees that Transmission Provider's liability arising out of this Agreement and the services provided under this Agreement, whether under theories of contract, negligence, tort, strict liability, warranty or equity will not exceed the amounts payable by Interconnecting Customer to Transmission Provider for the services that are the basis of such claim.

10.0 Governing Law. The validity, interpretation and performance of this Agreement shall be governed by the laws of the State of Idaho, without regard to its conflict of law principles; and in addition, shall be subject to all applicable federal laws, regulations and judicial or administrative orders of the Federal Energy Regulatory Commission. Venue for any action to enforce the terms and conditions of this Agreement shall be in Boise, Idaho.

11.0 Amendment. This Agreement may not be modified except by mutual agreement by a signed document duly executed by both Parties.

12.0 Waiver. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

13.0 Severability and Savings Clause. If any provision of this Agreement is held to be void, voidable, contrary to public policy, or unenforceable, that provision will be deemed severable from the Agreement as to the smallest part so held, and the remainder of the Agreement will continue in full effect as if the severed provision had not been included, in which case the Agreement will be construed and interpreted to implement the objectives of the Parties as stated in this Agreement. The Parties agree that neither Party will be deemed the drafter of any term that may subsequently be found to be ambiguous or vague.

14.0 Survival. This Agreement shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, to permit the determination and enforcement of liability obligations arising from acts or events that occurred while this Agreement was in effect.

15.0 Assignment and Subcontracts. This Agreement may not be transferred or assigned by either Party hereto without the prior written consent of the other Party, which such consent will not unreasonably be withheld. Transmission Provider may subcontract any portion of the work required by this Agreement without the permission of the Interconnecting Customer.

16.0 Successors and Assigns. This Agreement shall be binding upon and inure to the benefit of the Parties hereto and their respective successors and permitted assigns. Nothing in this Agreement shall be deemed to confer upon any other person any rights, remedies, obligations or liabilities under or by reason of this Agreement.

17.0 Notices. Any notice required by this Agreement is properly given if submitted in writing and delivered to the individual set forth below in person, delivered to a nationally recognized overnight courier service properly addressed and with delivery charges prepaid, delivered to the United States Postal Service properly addressed and with proper postage prepaid, transmitted by facsimile with confirmation of successful transmission, or transmitted by email. Either Party may change at any time the individual authorized to receive notice, an address, telephone number or email address by providing notice to the other Party.

If to Interconnecting Customer, to:

Company name	2nd contact info (if applicable)
EXERGY DEVELOPMENT GROUP OF IDAHO, LLC	
Attn: COLLIN RUDEEN	
title LEAD PROJECT ENGINEER	
Ph (208) 336-9793	Ph:
Fax (208) 336-9431	Fax
Email: CRUDEEN@EXERGYDEVELOPMENT.COM	Email:

If to the Transmission Provider, to:

Idaho Power Company
1221 West Idaho Street
Boise, ID 83702
Attn: Rowena Bishop
Ph 208.388.2658
Fax 208.388.5504
Email: rbishop@idahopower.com

18.0 Entire Agreement. This Agreement and its Attachments constitutes the complete agreement between the Parties concerning its subject matter and supersedes all previous communications, negotiation, and agreements, whether oral or written, with respect to this Agreement. None of the terms or obligations under this Agreement may be changed or waived in any manner whatsoever by an action or inaction of either Party unless in a writing duly executed by the Parties. Any provision of this Agreement which is prohibited or unenforceable in any jurisdiction shall be, as to such jurisdiction, ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions in any jurisdiction, and shall not invalidate or render unenforceable such provision in any other jurisdiction.

19.0 Dispute Resolution. Any dispute between Transmission Provider and Interconnection Customer involving the provisions of this Agreement shall be referred to a senior representative of Transmission Provider and a senior representative of Interconnection Customer for resolution on an informal basis as promptly as practicable.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

Transmission Provider:
Idaho Power Company – Delivery

By: [signature]

Title: PM Supervisor

Date: 3/2/11

Interconnection Customer:
EXERGY DEVELOPMENT GROUP OF IDAHO, LLC

By: [signature]

Title: LEAD PROJECT ENGINEER

Date: 2/10/2011

Attachment A

INTERCONNECTION CUSTOMER SCHEDULE ELECTION FOR CONDUCTING THE INTERCONNECTION FACILITIES STUDY

Transmission Provider shall use Reasonable Efforts to complete the study and issue a draft Interconnection Facilities Study report to Interconnection Customer within the following number of days after of receipt of an executed copy of this Interconnection Facilities Study Agreement:

Interconnection Customer to select:

____ ninety (90) Calendar Days with no more than a +/- 20 percent cost estimate contained in the report, or

_X_ - one hundred eighty (180) Calendar Days with no more than a +/- 10 percent cost estimate contained in the report.

Attachment B

DATA FORM TO BE PROVIDED BY INTERCONNECTION CUSTOMER WITH THE INTERCONNECTION FACILITIES STUDY AGREEMENT

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

One set of metering is required for each generation connection to the new ring bus or existing Transmission Provider station. Number of generation connections:

On the one line diagram indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

On the one line diagram indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

Will an alternate source of auxiliary power be available during CT/PT maintenance?
_____Yes _____No

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? _____Yes _____No (Please indicate on one line diagram).

What type of control system or PLC will be located at Interconnection Customer's Large Generating Facility?

____

What protocol does the control system or PLC use?

____

Please provide a 7.5-minute quadrangle of the site. Sketch the plant, station, transmission line, and property line.

Physical dimensions of the proposed interconnection station:

____

Bus length from generation to interconnection station:

____

Line length from interconnection station to Transmission Provider's transmission line.

____

Tower number observed in the field. (Painted on tower leg)* ____________________

Number of third party easements required for transmission lines*:

____

* To be completed in coordination with Transmission Provider.

Is the Large Generating Facility in the Transmission Provider's service area?

_____Yes _____No Local provider: ______________________________

Please provide proposed schedule dates:

Begin Construction	Date: 10/1/2011
Generator step-up transformer receives back feed power	Date: 12/31/2011
Generation Testing	Date: 1/15/2012
Commercial Operation	Date: 1/31/2012

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 33

Facilities Study Agreement

THIS AGREEMENT is made and entered into this 1st day of March 2011 by and between EXERGY DEVELOPMENT GROUP OF IDAHO, a LLC organized and existing under the laws of the State of IDAHO, ("Interconnection Customer,") and Idaho Power Company, a Corporation existing under the laws of the State of Idaho ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer on March 10, and March 15, 2010; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a system impact study and provided the results of said study to the Interconnection Customer; and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a facilities study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the system impact study in accordance with Good Utility Practice to physically and electrically connect the Small Generating Facility with the Transmission Provider's Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause a facilities study consistent with the standard Small Generator Interconnection Procedures to be performed in accordance with the Open Access Transmission Tariff.

3.0 The scope of the facilities study shall be subject to data provided in Attachment A to this Agreement.

4.0 The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s).

The facilities study shall also identify (1) the electrical switching configuration of the equipment, including, without limitation, transformer, switchgear, meters, and other station equipment, (2) the nature and estimated cost of the Transmission Provider's

Interconnection Facilities and Upgrades necessary to accomplish the interconnection, and (3) an estimate of the time required to complete the construction and installation of such facilities.

5.0 The Transmission Provider may propose to group facilities required for more than one Interconnection Customer in order to minimize facilities costs through economies of scale, but any Interconnection Customer may require the installation of facilities required for its own Small Generating Facility if it is willing to pay the costs of those facilities.

6.0 A deposit of $100,000.00 is due upon execution of this agreement by the Interconnection customer.

7.0 In cases where Upgrades are required, the facilities study must be completed within 45 Business Days of the receipt of this Agreement. In cases where no Upgrades are necessary, and the required facilities are limited to Interconnection Facilities, the facilities study must be completed within 30 Business Days.

8.0 Once the facilities study is completed, a facilities study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the facilities study must be completed and the facilities study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct a facilities study.

9.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

10.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

Transmission Provider:
Idaho Power Company - Delivery

Signed: [signature]

Printed Name: EDWARD KOSYDAR

Title: PM Supervisor

Date: 3/8/11

Interconnection Customer:
EXERGY DEVELOPMENT GROUP OF IDAHO LLC

Signed: [signature]

Printed Name: COLLIN RUDEEN

Title: LEAD PROJECT ENGINEER

Date: 3/1/2011

Attachment A to
Facilities Study Agreement

Data to Be Provided by the Interconnection Customer With the Facilities Study Agreement

1. Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

   On the one-line diagram, indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

   On the one-line diagram, indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

2. One set of metering is required for each generation connection to the new ring bus or existing Transmission Provider station. Number of generation connections:

   ____

3. Will an alternate source of auxiliary power be available during CT/PT maintenance? Yes ______ No ______

4. Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? Yes ______ No _____
   (Please indicate on the one-line diagram).

5. What type of control system or PLC will be located at the Small Generating Facility?

   ____

   ____

6. What protocol does the control system or PLC use?

   ____

   ____

7. Please provide a 7.5-minute quadrangle map of the site. Indicate the plant, station, transmission line, and property lines.

8. Physical dimensions of the proposed interconnection station:

____

9. Bus length from generation to interconnection station:

____

10. Line length from interconnection station to Transmission Provider's Transmission System.

____

11. Tower number observed in the field. (Painted on tower leg)*:

____

12. Number of third party easements required for transmission lines*:

____

* To be completed in coordination with Transmission Provider.

13. Is the Small Generating Facility located in Transmission Provider's service area?

Yes ______ No ______ If No, please provide name of local provider:

____

14. Please provide the following proposed schedule dates:

Begin Construction	Date: ______________
Generator Step-Up Transformers Receive Back Feed Power	Date: ______________
Generation Testing	Date: ______________
Commercial Operation	Date: ______________

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 34

IDAHO POWER.
An IDACORP Company

March 4, 2011
via email/Certified 70062760000194869058

Collin Rudeen
Exergy Development Group of Idaho
802 W Bannock Suite 1200
Boise, ID 83702

Subject: Salmon Creek Project #325 and Jack Ranch Wind Project #327

Dear Collin:

This is to acknowledge receipt of the signed Facility Study Agreement (FSA) and your deposit for the requested studies for the Salmon Creek and Jack Ranch Projects. Enclosed is a copy of the FSA for your records.

The Jack Ranch Project is listed as a NR/ER (Network Resource/Energy Resource) large generation project. No transmission studies have been done by Idaho Power for this project. Please be aware that while the Generator Interconnection (GI) process we are going through identifies any necessary interconnection requirements to our system, it does not secure the transmission rights nor determines the necessary network upgrades to move your project energy to the load or a point of delivery in our system. A transmission service request providing for transmission of energy is required to determine the necessary network upgrades to deliver your energy from the generator to the load or a point of delivery in our system. Failure to secure transmission could delay your project timeline and/or increase costs identified in the GI study reports. Please contact me as soon as possible if you have any questions.

Idaho Power Company's GI process requires a Generator Interconnection Agreement (GIA) to be in place before Commercial Operation may begin. The GIA describes the operating requirements, the estimated cost and payment responsibility for the project to be connected, and the projected construction timelines. I will be in touch with you to finalize the GIA when the Facility Studies are complete.

We expect the Facility Study to be completed by August 11, 2011, <u>but we have not received the technical information required to proceed.</u> Please contact Nancy Cyr, Project Leader, with the FSA Attachment A information as soon as possible at 208-388-6170.

Sincerely,

Rowena Bishop

Rowena Bishop
Operations Analyst

Enclosure: Executed FSA

C: Nancy Cyr/IPC

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 35

327

exergy
DEVELOPMENT GROUP

12 April 2011

Rowena Bishop
Idaho Power Company
Operations Analyst
1221 W. Idaho Street
Boise, ID 83702

RE: Interconnection applications and modifications

Rowena:

With respect to our conversations yesterday on the Jack Ranch overall complex, we ask the following revisions to be considered and implemented:

- Drop the NR/ER designation for GINT0327 on the 345kV Midpoint/Humboldt transmission line and move to an NR only designation.

- Reduce GINT0327 to 84 MW from 200 MW which may be utilized for the Rogerson Flats, Deep Creek, and Cottonwood wind parks. The reason for the 84 MW is based on whether it would make more sense to include Salmon Creek which is already scheduled for the 345kV line under GINT0325. If not necessary and would not affect any equipment, protocols, requirement, or controls incumbent to GINT0327 [assuming all four interconnects shall be metered at the low side of a 34.5kV/345kV transformer], then the reduction can be from 200 MW to 63 MW.

- Continued studies on GINT0325, Salmon Creek wind park.

- Continued studies on the Q332, Q323, and Q324 on the Upper Salmon/Wells 138kV line.

- Submission by Idaho Power Company of a cost estimate on Exergy's part of the upgrades on the Upper Salmon/Wells 138kV line biological surveys.

- Agreement in principle that, in the event Idaho Power Company needs the anticipated generating profile for developing scheduling, etc. on the 345kV Midpoint/Humboldt line, Exergy shall provide.

With regard to the changes to GINT0327, we assume that these modifications will not constitute "material modifications" under Idaho Power's Large Generator Interconnection Procedures (Attachment M to the OATT), and are therefore permitted without loss of queue position under Section 4.4. If Idaho Power believes the changes are material modifications or will impact the queue position, we would appreciate advance notice prior to instituting the changes, or taking action that would affect the queue position pursuant to Section 4.4.3.

I hope this encapsulates the discussion points in the meeting yesterday. We look forward to your response and discussion on the above.

Thank you.

Regards,

James T. Carkulis

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 36

IDAHO POWER®
An IDACORP Company

April 27, 2011
via email and Certified Mail # 70060100000014538461

James Carkulis
Exergy Development Group of Idaho
802 W Bannock, Suite 1200
Boise, ID 83702

Re: Interconnection applications/modifications Jack Ranch/Rogerson area
Exergy Projects (GI 322, 323, 324, 325 & 327)

Dear James:

I received your letter following the meeting we had Monday, April 11th for the Jack Ranch area GI projects. Idaho Power has considered Exergy's request for modifications pursuant to the Large Generator Interconnection Procedures ("LGIP") set forth in Attachment M of Idaho Power's Open Access Transmission Tariff. Each request is addressed below in the same order as in your letter:

1. You have requested to change the GI #327, Jack Ranch Wind, type of interconnection service from Network Resource, NR, concurrent with Energy Resource, ER, Interconnection Service to only NR Interconnection Service. The LGIP specifies that the customer may continue the concurrent ER study until the execution of the Interconnection Facility Study. The project Facility Study began on March 4, 2011 and is in progress, thus, this constitutes a Material Modification as defined in the OATT.

   Disposition of Material Modification: Idaho Power will use discretion under the OATT, since granting only NR Interconnection Service, in this instance, will not adversely impact any Interconnection Request with a later queue priority date. However, this requested change requires a restudy of the system impact. Idaho Power will offer a system impact re-study agreement covering both the change to NR Interconnection Service and the reduction in electrical power output.

2. You have requested reducing the electrical power output of GI# 327, Jack Ranch Wind. Again, the project Facility Study is in progress and the OATT provides for reduction of the project output up to the execution of the Interconnection Facility Study. This constitutes a Material Modification as defined in the OATT.

   Disposition of Material Modification: Idaho Power is willing to use discretion under the OATT, since granting the request for the reduced electrical power output, in this instance, would not adversely impact any Interconnection Request with a later queue priority date. If

P.O. Box 70 (83707)
1221 W. Idaho St.
Boise, ID 83702

you wish to reduce the project output, please initiate a request by providing a written response to me of the new electrical power output value, specified in megawatts (MW). Once this requested change is submitted, a restudy of the system impact will be required. Idaho Power will offer a system impact restudy agreement covering both the change to NR Interconnection Service and the reduction in electrical power output.

3. Idaho Power will continue study work on GI 325 Salmon Creek wind park, per your instruction (see April 12, 2011 Exergy letter).

4. Idaho Power will continue study work on GI 322, 323 and 324, per your instruction (see April 12, 2011 Exergy letter).

5. Regarding a cost estimate for biological studies on the Upper Salmon/Wells 138kV line, please contact Ron Jackson, Project Leader at 208-388-6262.

6. Idaho Power will make a separate request for additional information, which may include the generating profile, during the system impact re-study if required.

Please contact me as soon as possible if you have any questions.

Sincerely,

Rowena Bishop

Rowena Bishop
Operations Analyst
208-388-2658

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 37

exergy
DEVELOPMENT GROUP

28 April 2011

Rowena Bishop
Idaho Power Company

Re: Interconnection Request No. 327, Jack Ranch/Rogerson Flats area

Rowena:

I write in response to your letter sent to Exergy on April 27, 2011, which addressed several pending interconnection requests in the Jack Ranch/Rogerson Flats area, but only requires immediate response regarding Large Generator Interconnection Request No. 327.

In my letter to you dated April 12, 2011, we made two formal requests regarding that interconnection, as a follow up to the meeting we held at Idaho Power's headquarters on April 11, 2011. At that meeting we discussed using the Interconnection No. 327 to interconnect the Deep Creek, Rogerson Flats, Cottonwood, and Salmon Creek wind parks, and Idaho Power stated the steps we would need to take to do so.

First, my April 12th letter requested that Idaho Power drop the ER/NR designation and move to an NR only designation. Idaho Power stated that this would be necessary at our meeting. Second, my April 12th letter requested that Idaho Power reduce the interconnection output for No. 327 from its existing 200 MW maximum output to 84 MW as needed to interconnect the four above-referenced wind parks. Although I stated that the reduction may be lowered even further to 63 MW at some point, I would like to clarify that Exergy would like to proceed under the assumption that it will interconnect all four of the wind parks under Interconnection No. 327, and the maximum output will be 84 MW.

My April 12th letter stated our position that we did not believe that these modifications would be "material modifications," as defined in Attachment M to Idaho Power's approved Open Access Transmission Tariff (OATT), and would therefore be permitted without affecting the queue position under Section 4.4 and 4.4.3 of the OATT. Idaho Power's OATT defines "material modification" as "those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date."

Your April 27th letter in response concluded that each of our requested changes was a "material modification," and would require restudy. Exergy disagrees with this conclusion. I will address the two changes in the order of your letter.

Exergy Development Group 802 W Bannock, 12th Floor Boise, ID 83702 **P** 208.336.9793
F 208.336.9431

1. You stated that dropping the ER status after execution of the facility study agreement constitutes a "material modification." However, you also stated that "granting only NR Interconnection Service, in this instance, will not adversely impact any Interconnection Request with a later queue priority date." Thus, there is no material modification as defined under the OATT. Your letter provides no additional basis for any need to conduct an additional system impact restudy with regard to the granting only NR Interconnection Service. Removing ER status should not trigger the need to conduct additional study because the existing study already determined the resource could obtain NR Interconnection Service.

2. You stated that reducing the electrical output is a "material modification." But you also stated that "granting the request for reduced electrical output, in this instance, would not adversely impact any Interconnection Request with a later queue priority date." Thus, there is no material modification as defined under the OATT. If Exergy is willing to accept the upgrades necessary to interconnect 200 MW even though we will now only interconnect 84 MW, it is not clear why a restudy is necessary. Are different widgets needed to interconnect a lesser amount?

Exergy objects to the restudy under these circumstances without further explanation in writing within seven (7) days of this letter. These projects have contractual obligations to achieve a specified online date. Exergy is very concerned that a restudy – which can take up sixty (60) days under sections 4.4 and 7.6 of Attachment M the OATT – could cause delay in construction of interconnection facilities sufficient to prevent these projects from meeting their contractual obligations. We had expected that this reconfiguration of the interconnections would not have caused such a delay when we entered into the contracts last fall.

Finally, if Idaho Power conducts a restudy, Idaho Power must preserve whatever network transmission rights have been secured for these projects or for Interconnection No. 327. Under Section III of Idaho Power's OATT (Part 30.2), Idaho Power merchant must lodge a request with Idaho Power transmission that a new resource be designated as a network resource, and the OATT allows Idaho Power to lodge that request when Idaho Power has committed to purchase the generation pursuant to an executed contract. The contracts for the above-referenced wind parks have been executed and approved for some time now. Could you please inform me of the status of network transmission service request(s), and confirm that any restudy will not compromise any transmission rights preserved?

Regards,

James T. Carkulis

Exergy Development Group 802 W Bannock, 12th Floor Boise, ID 83702 **P** 208.336.9793
F 208.336.9431

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 38

An IDACORP Company

DRAFT
Generator Interconnection Facility Study Report

for the

Twin Falls County Wind Projects

Rogerson Flats Wind Park Project (#322)
Cottonwood Wind Park Project (#323)
Deep Creek Wind Park Project (#324)

for

Exergy Development Group of Idaho, LLC

in

Twin Falls County, ID

May 3, 2011

DRAFT - FACILITY STUDY REPORT (FSR)

Twin Falls County Wind Projects
Projects #322, 323, 324
May 3, 2011

1. General Facility Description

The proposed generation projects consist of up to 60 MW of wind power provided by 30 2.05 MW REPower generators. The projects are split into three unique Public Utility Regulatory Policies Act (PURPA) projects. The Interconnection Customer will provide the generators, 34.5 kV collector systems, step-up substation yard, and 34.5 kV to 230 kV transformer. The new substation will be tapped off the existing line #432 Upper Salmon Power Plant (USPR) to Wells 138 kV transmission line and will be solely utilized to interconnect the Interconnection Customer to the Idaho Power transmission system. The location of the new substation owned by the Interconnection Customer would be on private property in Idaho Power's Southern Idaho service territory approximately 4 miles west of the town of Rogerson, ID.

Interconnection Customer:
Collin Rudeen
Exergy Development Group of Idaho
802 W Bannock, Suite 1200
Boise, ID 83702
208-336-9793
crudeen@exergydevelpoment.com

A Standard Generator Interconnection Agreement(s) under Idaho Power Company's Open Access Transmission Tariff (OATT) or Schedule 72 between Interconnection Customer and Idaho Power Company – Delivery (Transmission Owner) for the Twin Falls County Wind Projects, specifically Generator Interconnection Projects # 322, 323, 324 will be prepared for this project.

1.1 Interconnection Point

The Interconnection Point for the Twin Falls County Wind Projects will be the transformer side of the disconnect switch labeled 101B on the attached single line drawing.

1.2 Point of Change of Ownership

The Point of Change of Ownership for the Twin Falls County Wind Projects is electrically the same as the Interconnection Point (note that physically the Interconnection Customer will own the substation site where Idaho Power will locate facilities).

1.3 Customer's Interconnection Facilities

The Interconnection Customer will install generators, step-up transformers, distribution collector system, step-up substation, 34.5 kV to 138 kV transformer and associated auxiliary equipment. The Interconnection Customer will build, own, and maintain facilities electrically located on the Interconnection Customer side of the Point of Change of Ownership.

1.4 Other Facilities Provided by Interconnection Customer

1.4.1 Telecommunications

In addition to communication circuits that may be needed by the Interconnection Customer, the Interconnection Customer shall provide the following communication circuits for Idaho Power's use:

1. One POTS (Plain Old Telephone Service) dial-up circuit for querying the revenue meter at the generation interconnection site.
2. One leased DDS (Digital Data Service) circuit for SCADA between the generation interconnection site and (EMS FEP location). This circuit must operate at 19.2 kbps data rate or higher. Please note that Frame Relay service is not acceptable.
3. One leased DDS (Digital Data Service) circuit for <u>each</u> required Phasor Measurement Unit (PMU) between the generation interconnection site and (PMU Concentrator location). This circuit must operate at 19.2 kbps data rate or higher. Please note that Frame Relay service is not acceptable.

The Interconnection Customer is required to coordinate with a communications provider to provide the communications circuits and pay the associated one time setup and periodic charges. The communication circuits will need to be installed and operational prior to generating into Idaho Power system. Note that installation by communications provider may take several months and should be ordered in advance to avoid delaying the project. If the communication circuit types listed above are not available at the site by a communications provider, the Interconnection Customer shall confer with Idaho Power.

If high voltage protection is required by the communications provider for the incoming communications provider cable, the high voltage protection assembly shall be engineered and supplied by the Interconnect Customer. Options are available for indoor or outdoor mounting. The high voltage protection assembly shall be located in a manner that provides Idaho Power 24-hour access to the assembly for trouble-shooting of Idaho Power owned equipment.

1.4.2 Grounding

The Interconnection Customer will install transformer configurations that will provide a ground source to the transmission system.

1.4.3 Generator Output Limit Control

The Interconnection Customer will install equipment to receive signals from Idaho Power Grid Operations for Generation Output Limit Control ("GOLC") - see Section 3 Operating Requirements.

1.4.4 Property, Site Work, and Substation Building

The Interconnection Customer will acquire property for the substation and provide access, land clearing, grading, grounding, and fencing for the entire yard (including the Idaho Power side). A building within the substation will be provided by the Interconnection Customer and a separate, lockable room will be allocated inside the building for Idaho Power facilities. The substation will be owned and maintained by the Interconnection Customer.

1.4.5 Local Service

The Interconnection Customer is responsible to arrange for local service to the control building for use by the both the Interconnection Customer and Idaho Power.

1.4.6 Easements

The Interconnection Customer will provide to Idaho Power a surveyed (Metes & Bounds) legal description along with exhibit map for Idaho Power's facilities. After the legal description has been delivered to IPCO for review, IPCO will supply to the Interconnection Customer a completed IPCO easement for signature by the land owner of record. Once the signatures have been secured, the Interconnection Customer will return the signed easement to IPCO for recording.

1.5 Idaho Power Company's Interconnection Facilities

Idaho Power will install a short 138 kV transmission tap between the existing line #432 USPR-Wells 138 kV transmission line and the Interconnection Customer owned substation. The tap is assumed to be approximately 600 feet long or less. A dead-end structure, 138 kV circuit breaker, two air-break switches, and associated relaying, control and metering equipment in the substation yard and building up to the Point of Change of Ownership will be installed. Revenue metering will be accomplished at the 138 kV side of the transformer.

1.5.1 Metering

Idaho Power will install a 34.5 kV metering package for each of the three wind parks. They will be overhead equipment located on the Interconnection Customer owned distribution system near each of the unique wind parks.

1.6 Interconnection Facilities Cost Estimate

The following good faith estimates are provided in 2011 dollars:

Description	Ownership	Cost Estimate
Interconnection Facilities:		
Interconnection Station	IPC	$950,000
138 kV Transmission Line Tap	IPC	$50,000
SUBTOTAL		**$1,000,000**
See Section 6 for Project Grand Total		

2. Milestones

Date	Milestones
TBD	*Construction Funds Received by IPCO*
18 Months after Construction Funds Received by IPCO	*IPCO Construction Complete*
1 Month after IPCO Construction Complete	*IPCO Commissioning Complete*
	Commercial Operation Date [tbd by seller]
These milestone dates assume that material can be procured and that outages to the existing transmission line are available to be scheduled. Additionally, any permitting issues outside the immediate control of Idaho Power could also influence the Commercial Operation Date.	

3. Operating Requirements

The project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-1992 *IEEE Recommended Practices and requirements for harmonic Control in Electrical Power Systems* or any subsequent standards as they may be updated from time to time.

The Twin Falls County Wind Projects will be allowed to deliver the net output of 60 MW at the Interconnection Point subject to reductions directed by Idaho Power Grid Operations during transmission system contingencies. When outages occur, the Project will be subject to Generator Output Limit Control ("GOLC") and will have equipment capable of receiving signals from Idaho Power for GOLC. Generator Output Limit Control will be a signal from Idaho Power to the Project indicating maximum output allowed during transmission contingencies.

Interconnection Customer will be able to modify facilities on the Interconnection Customer side of the Interconnection Point with no impact upon the operation of the transmission or distribution system whenever the generation facilities are electrically isolated from the system via the 101B airbreak disconnect switch or other approved methods by Idaho Power system operations.

4. Reactive Power

The Project will be capable of +/- 0.95 power factor operation, as measured at the Interconnection Point, for all MW production levels from zero MW output to full rated MW output. The customer will be provided a voltage schedule from Idaho Power Grid Operations prior to Commercial Operation of the project.

5. Upgrades

5.1 Transmission Upgrades

The three wind projects are planned for interconnection to the USPR-Wells 138kV transmission line #432. In order to integrate these projects, portions of the line will have to be re-conductored with larger wire (per system impact study dated Jan 4, 2010).

GINT0322 Rogerson Flats – This 20MW project will require re-conductoring the #432 line between USPR and Blue Gulch Substation (BUGU), a distance of 10.3 miles. There are two significant obstacles associated with this task:

- The primary obstacle is acquiring a BLM permit for this work, since all but a mile or so of this section of line is on BLM land. The duration of the permitting process can vary depending on BLM requirements, study findings and their approval process. This time would likely be between 12 and 36 months, a timeline that starts after botantical/biological/cultural surveys have been completed. Those surveys must be conducted during a spring window that is typically April 15 – June 1. A missed window delays the start of the timeline 1 year.
- The second obstacle is getting the line out of service so it can be re-conductored. The line serves two IPCo stations and terminates at Wells Substation. Other existing sources to Wells have very marginal capacity to support the station load and have no capacity to backfeed IPCo's stations. A two month minimum outage would be required for the rebuild during which time Wells would be very vulnerable if supported only by existing sources. Alternative sources (yet to be determined) would be required for the IPCo stations.

GINT0323 Cottonwood – The addition of this 20MW project to Line #432 can be accommodated with the 10.3 mile reconductor described above.

GINT0324 Deep Creek – The first 10MW of this 20MW project can be accommodated with the 10.3 mile re-conductor described above. The second 10 MW (total of 60MW) would require re-conductoring the line from BUGU to the interconnect point, a distance of 34 miles. The majority of this line section is also on BLM land. The outage duration required would be on the order of 6 months.

The $1.5M estimate for the 10.3 mile line rebuild represents typical costs for re-conductoring 138 kV line that is easily accessible and assumes 10% pole replacement. It also includes costs to perform the BLM required surveys (typically $20K to $50k). This estimate would be refined following development of a construction plan. For the purpose of this report, a $1M estimate was used for mitigation of the outage during the line rebuild. That estimate would be refined once a mitigation plan is developed.

Regarding BLM permitting, the surveys required to initiate that process would be performed by a qualified contractor hired by IPC. The survey contractor will require specific information about the line construction plan so that guidelines for the survey can be established.

Before a construction plan can be created the following tasks would need to be performed:

- A pole by pole inspection to determine pole replacement required.
- A study of road improvements or new roads required for access.
- A determination if ROW needs to be expanded for temporary staging areas, pole replacement or pole relocation.

Some of the line resides on private land so permission from private landowners would have to be obtained to conduct surveys required by the BLM on the private sections.

Creating a construction plan to prepare for the surveys would be approximately a 6 month long process, pushing the survey start time to the 2012 spring window. This is reflected on the preliminary schedule included with this report.

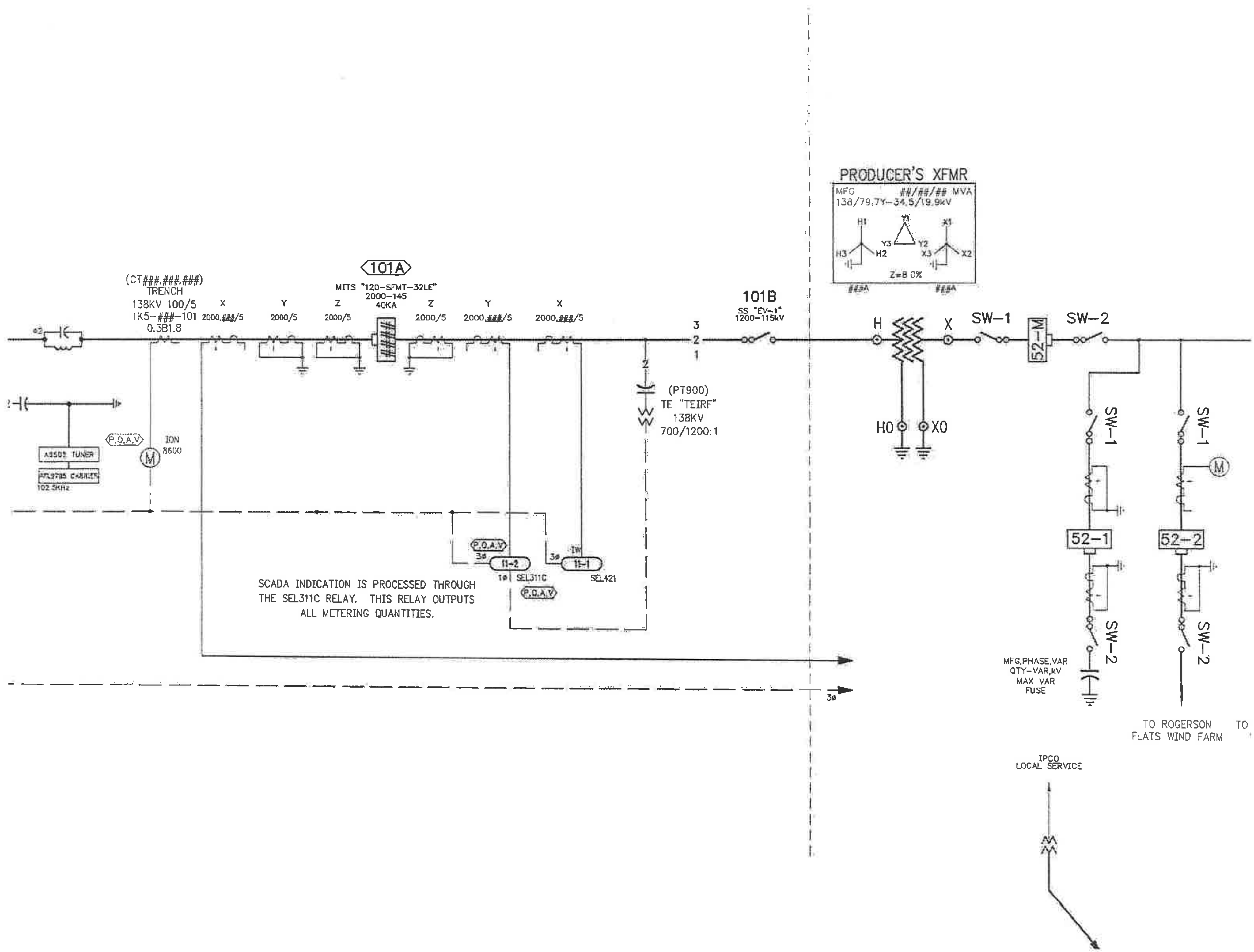
6. Total Estimated Costs

The following good faith estimates are provided in 2011 dollars:

Description	Ownership	Cost Estimate
Interconnection Facilities (from section 1.6):		
Interconnection Station	IPC	$950,000
138 kV Transmission Line Tap	IPC	$50,000
SUBTOTAL		**$1,000,000**
Upgrades to Transmission:		
Re-conductor 10.3 miles of line #432	IPC	$1,500,000
Re-conductor 34 miles of line #432	IPC	$5,000,000
Mitigate outage (plan to be determined)		$1,000,000
SUBTOTAL		**$7,500,000**
GRAND TOTAL		**$8,500,000**

Note Regarding Transmission Service:

This Facility Study is a Network Resource Interconnection Facility Study. This study identifies the facilities necessary to integrate the Generating Facility into Idaho Power's network to serve load within Idaho Power's balancing area. Network Resource Interconnection Service in and of itself does not convey any right to deliver electricity to any specific customer or Point of Delivery.



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1K5-###-101
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X 2000.###/5
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2000-145
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A3505 TUNER
RFL9785 CARRIER
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P.Q.A.V
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11-2
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SEL421
SCADA INDICATION IS PROCESSED THROUGH THE SEL311C RELAY. THIS RELAY OUTPUTS ALL METERING QUANTITIES.
(PT900)
TE "TEIRF"
138KV
700/1200:1
101B
SS "EV-1"
1200-115kV
PRODUCER'S XFMR
MFG ##/##/## MVA
138/79.7Y-34.5/19.9kV
H1 H2 H3
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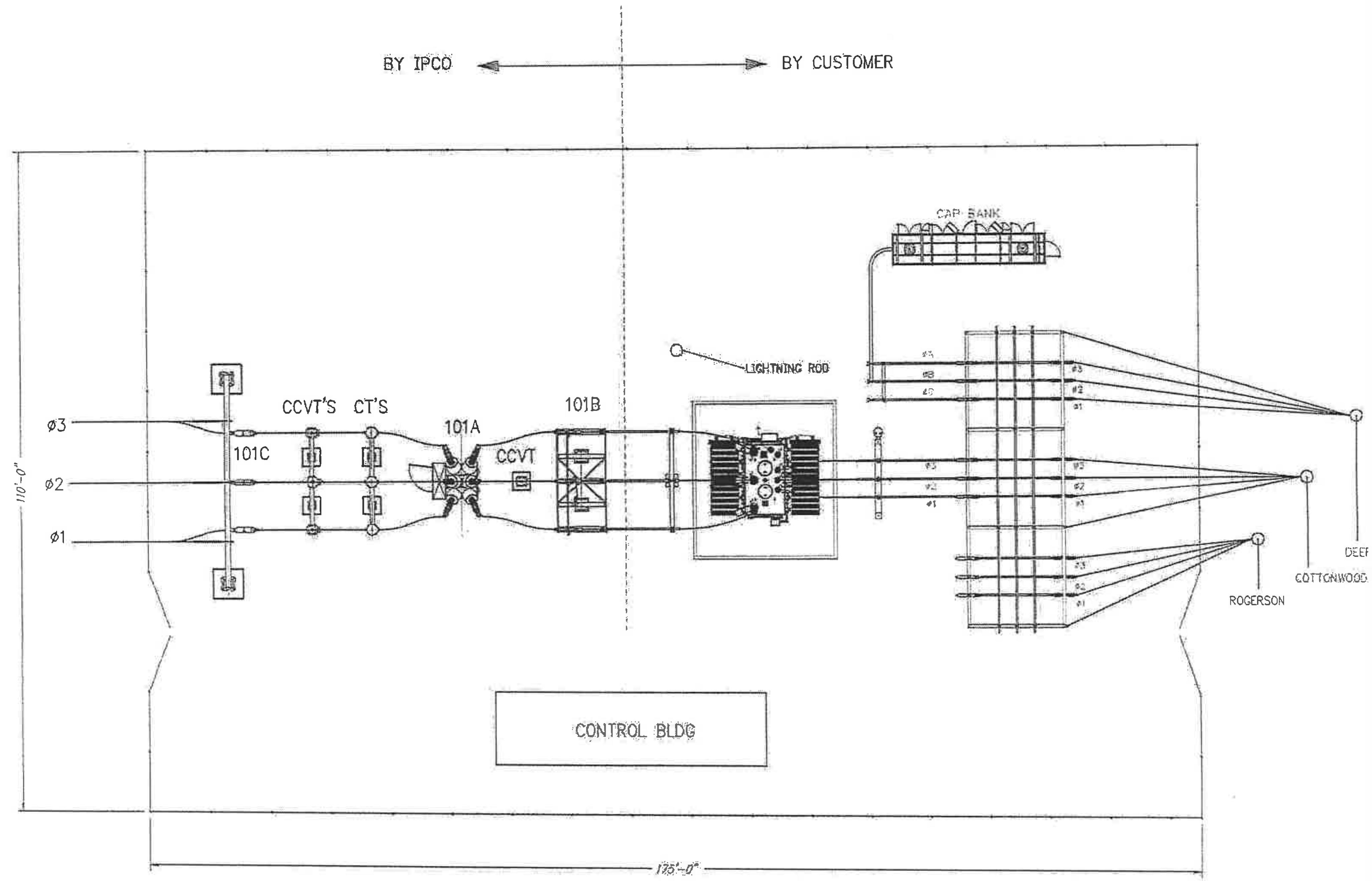
TO ROGERSON FLATS WIND FARM
TO
IPCO LOCAL SERVICE



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CAP BANK
CONTROL BLDG
ROGERSON
COTTONWOOD
DEER

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 39

IDAHO POWER.
An IDACORP Company

May 20, 2011

James Carkulis
Exergy Development Group of Idaho
Via email only

RE: GI # 327, Jack Ranch/Rogerson Flats area

Dear James:

This letter is responding to your April 28, 2011 letter. Sorry for the confusion generated by Idaho Power Company's April 27, 2011 letter to you. The letter should have stated that the requested changes did not conform to changes allowed under Section 4.4.3 in Attachment M of the Open Access Transmission Tariff. Therefore, each change required a material modification review to determine if the change would adversely impact any Interconnection Request with a later queue priority date. With the clarification above, let me explain the requirements for the restudy.

During the GI 327 System Impact Study, Idaho Power studied the requirements only to integrate the generation project. This study did not include analysis of transmission requirements to deliver the power to Idaho Power's native load. Additionally, the transmission system impact study for Cottonwood Wind Park, Deep Creek Wind Park, and Rogerson Flats Wind Park, were studied based on their interconnection at 138 kV. The change of the three projects from 138 to 345 kV will require a restudy due to the different integration voltages and the associated transmission lines terminate at substations that are about 30 miles apart on the Idaho Power west to east transmission network.

These two configuration differences may result in a different power flow on the transmission network which may limit the ability to deliver the generated power to Idaho Power's native load. The required restudy will be performed assuming 84 MWs integrated at 345 kV and, to avoid duplication of resources, will exclude the projects connected at 138 kV. Thus, the network transmission that was acknowledged as available to Idaho Power's Power Supply department for 80 MWs, as described in a letter to Exergy on April 18, 2011, will be assumed available for the 84 MWs integrated at 345 kV as you have requested.

Please contact Idaho Power's Power Supply department to initiate a transmission system impact restudy for the generation interconnection configuration that you have proposed. If you have questions, you may contact me at (208) 388-2701.

Sincerely,

David M Angell

Dave Angell
Planning Manager

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 40

3 June 2011

Dave Angell
Rowena Bishop
Idaho Power Company

Re: Interconnection Request No. 327, Jack Ranch/Rogerson Flats area

Dave and Rowena:

Thank you for your letter sent to Exergy on May 20, 2011 and subsequent communications, which clarified Idaho Power's position on the interconnection requests in the Jack Ranch/Rogerson Flats area. I have also copied Randy Allphin with this letter, and request that Idaho Power's supply department initiate the additional network transmission designation steps necessary to deliver to native load the entire 84 MWs for the Deep Creek, Rogerson Flats, Cottonwood, and Salmon Creek wind parks from the point of interconnection on the 345 kV line used in Interconnection Request Nos. 325 and 327.

As agreed at our meeting on April 11, 2011, Exergy lodged two requests that Idaho Power stated would enable Exergy to use Interconnection No. 327 to interconnect the Deep Creek, Rogerson Flats, Cottonwood, and Salmon Creek wind parks: (1) drop the ER/NR designation and move to an NR only designation, and (2) reduce the interconnection output for No. 327 from its then-existing 200 MW maximum output to 84 MW.

Thank you for clarifying in your May 20th letter, that these two requests merely required material modification review. Exergy understood your May 20th letter as confirmation that these two changes to Interconnection Request No. 327 will not require a restudy of the system impact study for the interconnection request under Attachment M to the OATT. Thank you for confirming in email that, for purposes of the interconnection, Idaho Power is implementing these two changes and proceeding with the facility study under the existing facility study agreement dated February 11, 2011.

With regard to the network integration transmission service governed by Part III of the OATT, Idaho Power stated in a letter dated April 22, 2011, from Michael Darrington, that 80 MW of network transmission was reserved for these four projects. Thank you for confirming in your May 20th letter that the 80 MWs of transmission already reserved for these projects will be available with all four projects interconnecting at the 345 kV point of interconnection. Exergy understands, as you explained in your May 20th letter, that under Part III of the OATT, Idaho Power's power supply business unit will need to request a modification to its prior requests to account for the changed point of interconnection from the 138 kV line to the 345 kV line for three of the projects (Deep Creek, Rogerson Flats, Cottonwood). I would note, however, that the Salmon Creek project has always been planned to interconnect at the 345 kV point of interconnection under Interconnection Request No. 325. Therefore, the 20 MW of network transmission currently reserved for that project, as described in Mr. Darrington's April 22nd letter, should not be impacted by moving the point of interconnection for the other three projects. I would also note that the System Impact Study for Nos. 325 and 327 stated, on page 4, "Existing IPC generation utilizes 262.5 MW of this transfer capability, leaving 97.5 MW of capacity available for firm transmission northbound."

Exergy does not believe that the additional investigation of available network transmission under Part III of the OATT should delay progress on the interconnection. We thank Idaho Power for proceeding with the Facilities Study and hope that construction of the interconnection facilities will be able to commence soon.

Regards,

James T. Carkulis

cc: Randy Allphin, Idaho Power Company

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 41

Generator Interconnection Facility Study Report

for the

Twin Falls County Wind Projects

Rogerson Flats Wind Park Project (#322)
Cottonwood Wind Park Project (#323)
Deep Creek Wind Park Project (#324)

for

Exergy Development Group of Idaho, LLC

in

Twin Falls County, ID

June 7, 2011

FACILITY STUDY REPORT (FSR)

Twin Falls County Wind Projects
Projects #322, 323, 324
June 7, 2011

1. General Facility Description

The proposed generation projects consist of up to 60 MW of wind power provided by 30 2.05 MW REPower generators. The projects are split into three unique Public Utility Regulatory Policies Act (PURPA) projects. The Interconnection Customer will provide the generators, 34.5 kV collector systems, step-up substation yard, and 34.5 kV to 230 kV transformer. The new substation will be tapped off the existing line #432 Upper Salmon Power Plant (USPR) to Wells 138 kV transmission line and will be solely utilized to interconnect the Interconnection Customer to the Idaho Power transmission system. The location of the new substation owned by the Interconnection Customer would be on private property in Idaho Power's Southern Idaho service territory approximately 4 miles west of the town of Rogerson, ID.

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3. Operating Requirements

The project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-1992 *IEEE Recommended Practices and requirements for harmonic Control in Electrical Power Systems* or any subsequent standards as they may be updated from time to time.

The Twin Falls County Wind Projects will be allowed to deliver the net output of 60 MW at the Interconnection Point subject to reductions directed by Idaho Power Grid Operations during transmission system contingencies. When outages occur, the Project will be subject to Generator Output Limit Control ("GOLC") and will have equipment capable of receiving signals from Idaho Power for GOLC. Generator Output Limit Control will be a signal from Idaho Power to the Project indicating maximum output allowed during transmission contingencies.

Interconnection Customer will be able to modify facilities on the Interconnection Customer side of the Interconnection Point with no impact upon the operation of the transmission or distribution system whenever the generation facilities are electrically isolated from the system via the 101B airbreak disconnect switch or other approved methods by Idaho Power system operations.

4. Reactive Power

The Project will be capable of +/- 0.95 power factor operation, as measured at the Interconnection Point, for all MW production levels from zero MW output to full rated MW output. The customer will be provided a voltage schedule from Idaho Power Grid Operations prior to Commercial Operation of the project.

5. Upgrades

5.1 Transmission Upgrades

The three wind projects are planned for interconnection to the USPR-Wells 138kV transmission line #432. In order to integrate these projects, portions of the line will have to be re-conductored with larger wire (per system impact study dated Jan 4, 2010).

GINT0322 Rogerson Flats – This 20MW project will require re-conductoring the #432 line between USPR and Blue Gulch Substation (BUGU), a distance of 10.3 miles. There are two significant obstacles associated with this task:

- The primary obstacle is acquiring a BLM permit for this work, since all but a mile or so of this section of line is on BLM land. The duration of the permitting process can vary depending on BLM requirements, study findings and their approval process. This time would likely be between 12 and 36 months, a timeline that starts after botantical/biological/cultural surveys have been completed. Those surveys must be conducted during a spring window that is typically April 15 – June 1. A missed window delays the start of the timeline 1 year.
- The second obstacle is getting the line out of service so it can be re-conductored. The line serves two IPCo stations and terminates at Wells Substation. Other existing sources to Wells have very marginal capacity to support the station load and have no capacity to backfeed IPCo's stations. A two month minimum outage would be required for the rebuild during which time Wells would be very vulnerable if supported only by existing sources. Alternative sources (yet to be determined) would be required for the IPCo stations.

GINT0323 Cottonwood – The addition of this 20MW project to Line #432 can be accommodated with the 10.3 mile reconductor described above.

GINT0324 Deep Creek – The first 10MW of this 20MW project can be accommodated with the 10.3 mile re-conductor described above. The second 10 MW (total of 60MW) would require re-conductoring the line from BUGU to the interconnect point, a distance of 34 miles. The majority of this line section is also on BLM land. The outage duration required would be on the order of 6 months.

The $1.5M estimate for the 10.3 mile line rebuild represents typical costs for re-conductoring 138 kV line that is easily accessible and assumes 10% pole replacement. It also includes costs to perform the BLM required surveys (typically $20K to $50k). This estimate would be refined following development of a construction plan. For the purpose of this report, a $1M estimate was used for mitigation of the outage during the line rebuild. That estimate would be refined once a mitigation plan is developed.

Regarding BLM permitting, the surveys required to initiate that process would be performed by a qualified contractor hired by IPC. The survey contractor will require specific information about the line construction plan so that guidelines for the survey can be established.

Before a construction plan can be created the following tasks would need to be performed:

- A pole by pole inspection to determine pole replacement required.
- A study of road improvements or new roads required for access.
- A determination if ROW needs to be expanded for temporary staging areas, pole replacement or pole relocation.

Some of the line resides on private land so permission from private landowners would have to be obtained to conduct surveys required by the BLM on the private sections.

Creating a construction plan to prepare for the surveys would be approximately a 6 month long process, Therefore the survey would take place during the 2012 spring window. This is reflected on the preliminary schedule included with this report.

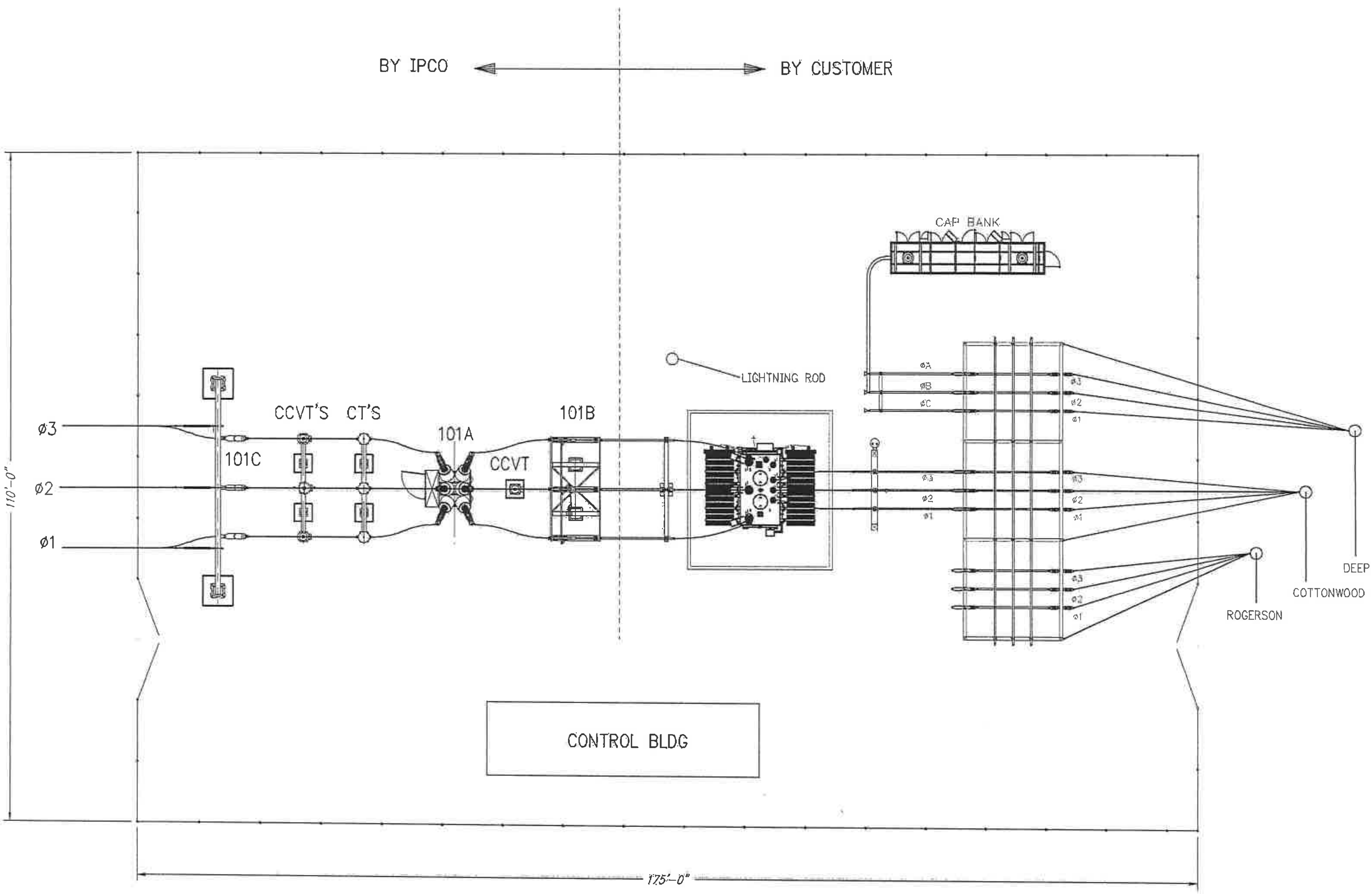
6. Total Estimated Costs

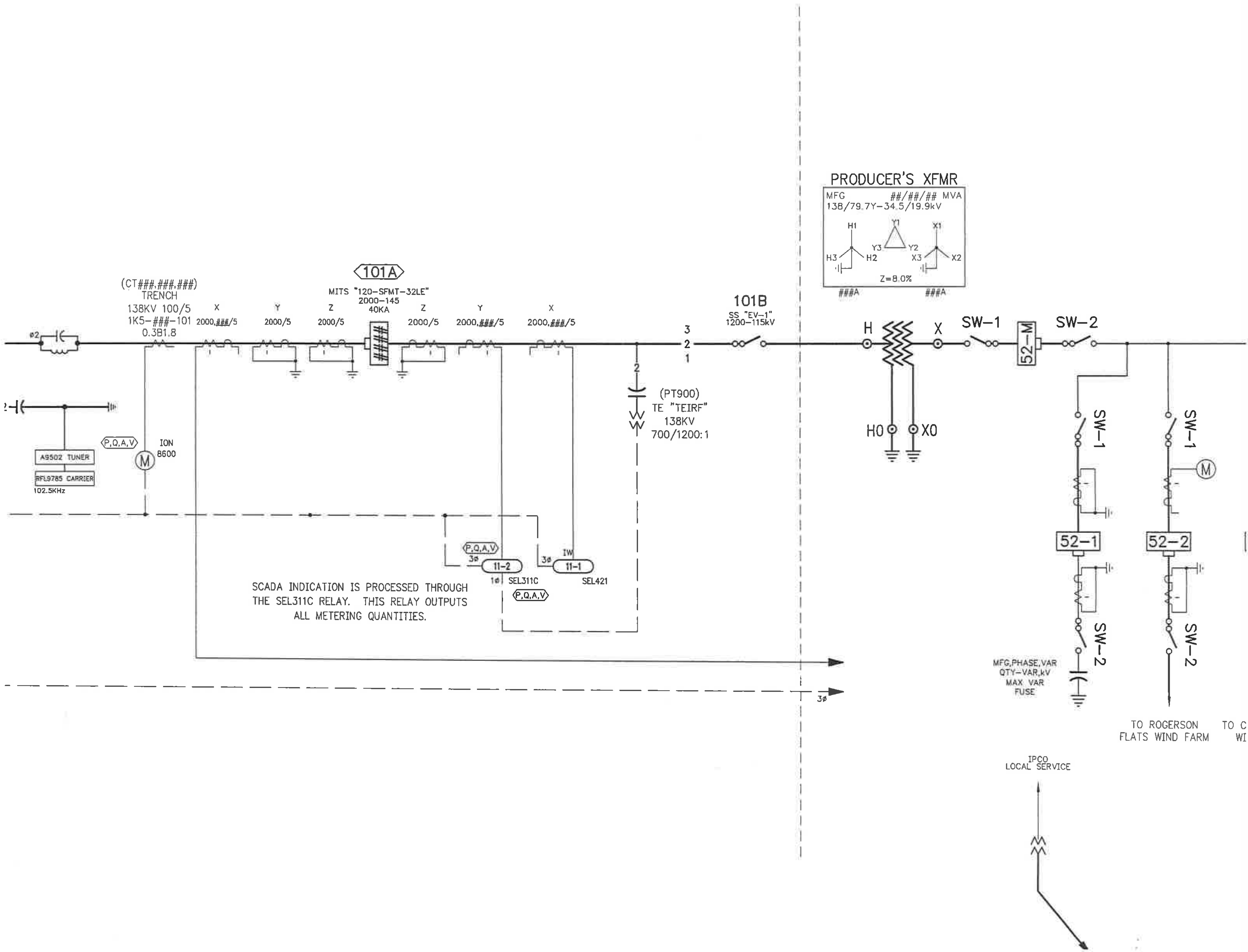
The following good faith estimates are provided in 2011 dollars:

Description	Ownership	Cost Estimate
Interconnection Facilities (from section 1.6):		
Interconnection Station	IPC	$950,000
138 kV Transmission Line Tap	IPC	$50,000
SUBTOTAL		**$1,000,000**
Upgrades to Transmission:		
Re-conductor 10.3 miles of line #432	IPC	$1,500,000
Re-conductor 34 miles of line #432	IPC	$5,000,000
Mitigate outage (plan to be determined)		$1,000,000
SUBTOTAL		**$7,500,000**
GRAND TOTAL		**$8,500,000**

Note Regarding Transmission Service:

This Facility Study is a Network Resource Interconnection Facility Study. This study identifies the facilities necessary to integrate the Generating Facility into Idaho Power's network to serve load within Idaho Power's balancing area. Network Resource Interconnection Service in and of itself does not convey any right to deliver electricity to any specific customer or Point of Delivery.

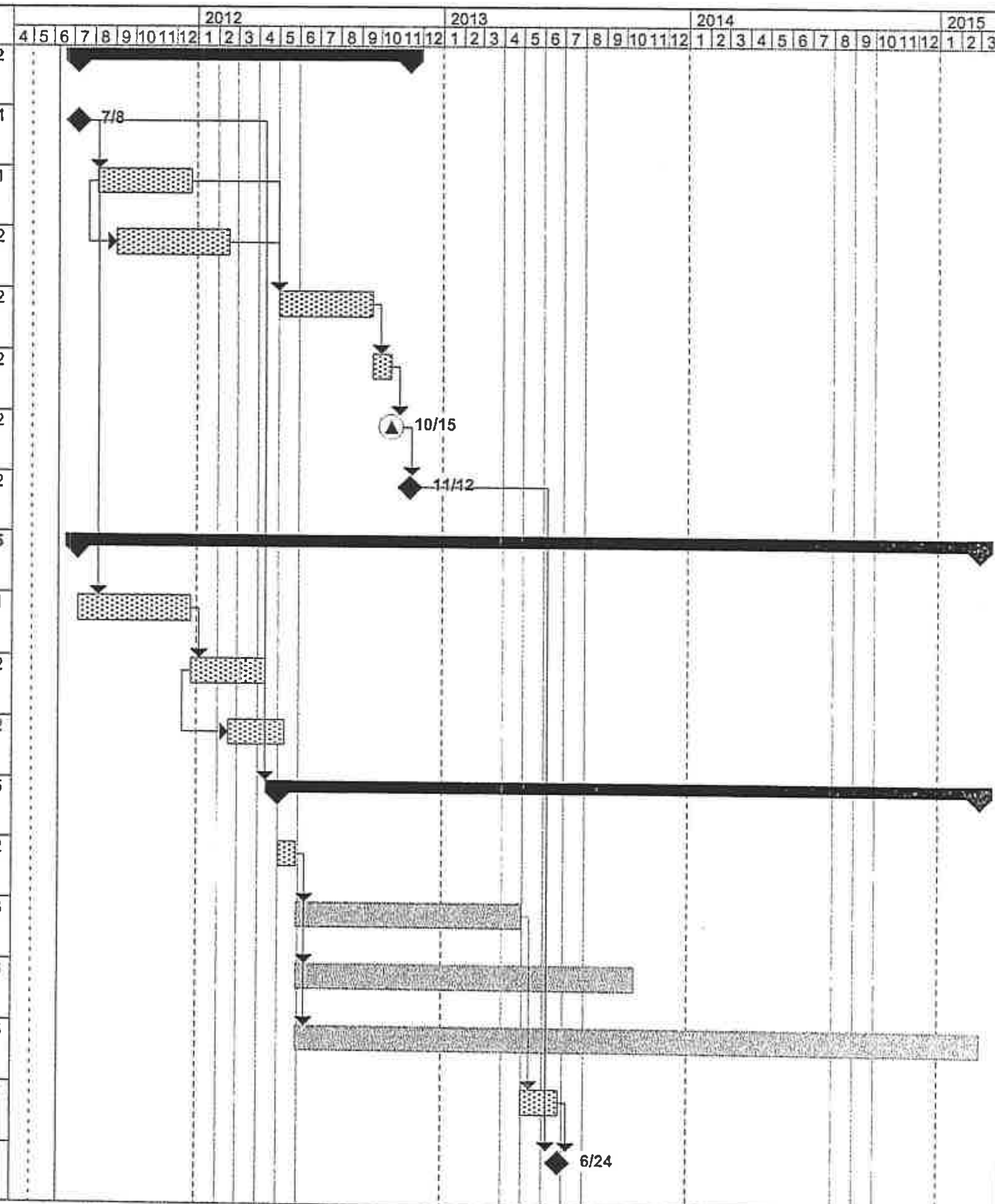

BY IPCO
BY CUSTOMER
CAP BANK
LIGHTNING ROD
ø3
ø2
ø1
101C
CCVT'S
CT'S
101A
CCVT
101B
øA
øB
øC
DEEP
COTTONWOOD
ROGERSON
CONTROL BLDG
110'-0"
175'-0"



PRODUCER'S XFMR
MFG ##/##/## MVA
138/79.7Y-34.5/19.9kV
H1 H2 H3 Y1 Y2 Y3 X1 X2 X3
Z=8.0%
###A
###A
101A
MITS "120-SFMT-32LE"
2000-145
40KA
(CT###,###,###)
TRENCH
138KV 100/5
1K5-###-101
0.3B1.8
X 2000,###/5
Y 2000/5
Z 2000/5
Z 2000/5
Y 2000,###/5
X 2000,###/5
ø2
A9502 TUNER
RFL9785 CARRIER
102.5KHz
P,Q,A,V
ION
8600
101B
SS "EV-1"
1200-115kV
3
2
1
(PT900)
TE "TEIRF"
138KV
700/1200:1
H
X
H0
X0
SW-1
52-M
SW-2
P,Q,A,V
3ø
11-2
1ø
SEL311C
P,Q,A,V
3ø
IW
11-1
SEL421
SCADA INDICATION IS PROCESSED THROUGH THE SEL311C RELAY. THIS RELAY OUTPUTS ALL METERING QUANTITIES.
3ø
SW-1
52-1
SW-2
MFG,PHASE,VAR
QTY-VAR,kV
MAX VAR
FUSE
SW-1
52-2
SW-2
TO ROGERSON FLATS WIND FARM
TO C
WI
IPCO
LOCAL SERVICE

ID	Task Name	Duration	Start	Finish
1	**Interconnect Station ($900k)**	352 days	Fri 7/8/11	Mon 11/12/12
2	Funds received	0 days	Fri 7/8/11	Fri 7/8/11
3	Design	5 mons	Fri 8/5/11	Thu 12/22/11
4	Long Lead Material	6 mons	Fri 9/2/11	Thu 2/16/12
5	Construction	5 mons	Tue 5/1/12	Mon 9/17/12
6	Test and Commission	1 mon	Tue 9/18/12	Mon 10/15/12
7	Station in service	0 mons	Mon 10/15/12	Mon 10/15/12
8	10MW firm Operation	0 days	Mon 11/12/12	Mon 11/12/12
9	**Line Re-Conductor ($1M)**	952 days	Fri 7/8/11	Mon 3/2/15
10	Inspect line, develop constr plan	6 mons	Fri 7/8/11	Thu 12/22/11
11	Design	4 mons	Fri 12/23/11	Thu 4/12/12
12	Long Lead Material	3 mons	Fri 2/17/12	Thu 5/10/12
13	**BLM Permit**	740 days	Tue 5/1/12	Mon 3/2/15
14	Environmental Surveys	1 mon	Tue 5/1/12	Mon 5/28/12
15	Catagorical Exclusion	12 mons	Tue 5/29/12	Mon 4/29/13
16	EA	18 mons	Tue 5/29/12	Mon 10/14/13
17	EIS	36 mons	Tue 5/29/12	Mon 3/2/15
18	Construction (permit dependant)	2 mons	Tue 4/30/13	Mon 6/24/13
19	50MW firm Operation	0 days	Mon 6/24/13	Mon 6/24/13

(ASSUMES CAT. EXCLUSION)



Project: GINT0322 Sched.mpp
Date: Tue 6/7/11

Task
Split
Progress
Milestone
Summary
Project Summary
External Tasks
External Milestone
Deadline

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 42

Cyr, Nancy

From: James Carkulis [jcarkulis@exergydevelopment.com]
Sent: Friday, July 22, 2011 9:52 AM
To: Bishop, Rowena
Cc: Dustin Shively; Josh Gunderson
Subject: RE: Final Facility Study Report - GINT0322, 0323, 0324

Rowena:

I believe we can withdraw anything that does not have to do with the 345kV interconnect at this time. I do not believe, given the reports, we shall be connecting anything to the 138kV line.

Sorry, my frenetic paced mistake for not getting back to you.

James

James T Carkulis
802 W Bannock, 12th Floor Boise, ID 83702
Office: 208.336.9793 | Mobile: 406.459.3013
jcarkulis@exergydevelopment.com
www.exergydevelopment.com

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 43

IDAHO POWER®
An IDACORP Company

August 9, 2011

Shaun Jensen
Idaho Power Company – Power Supply
HAND DELIVERED

Re: System Impact Study Agreements for Network Service Requests

Dear Shaun:

Thank you for your application for network transmission service with Idaho Power Company – Transmission (Delivery). We have determined that it will be necessary to perform a System Impact Study and Restudy to evaluate the impact of these service requests on Idaho Power's transmission system due to the additional request and change of interconnection point to 345kV.

Date of request	OASIS	POR	POD	Amount (MW)	Requested Dates of Service	Deposit
09/22/2010	74705988	MDSK	IPCO	20	09/01/11 – 09/01/32	$10,000
09/22/2010	74705990	MDSK	IPCO	20	09/01/11 – 09/01/32	
09/22/2010	74705993	MDSK	IPCO	20	09/01/11 – 09/01/32	
09/22/2010	74705995	MDSK	IPCO	20	09/01/11 – 09/01/32	
08/02/2011	76002279	MDSK	IPCO	4	09/01/11 – 09/01/32	

Attached please find System Impact Study Agreements (SISA) for the above transmission requests. The Agreement describes your request, the studies required to meet this request, the responsibilities and obligations of both parties and the work schedules required. Estimated cost for the study is $10,000. This $10,000 deposit amount will need to be sent to Delivery with the execution of the SISAs. If these agreements are acceptable to you, please sign and return them to us for our signature. We will then send you signed copies and keep the originals for our files. If we do not receive the executed agreements and deposit by close of business on August 24, 2011, we will consider your transmission requests to have been withdrawn and terminated.

If you do not wish for a study to be done, please withdraw your request on OASIS as soon as possible. Failure to respond to this letter will be considered as an election not to execute a SISA. If you have any questions, please feel free to contact me. Thanks.

Regards,

Beth Ryan
Operations Analyst, 208.388.2846
BRyan@idahopower.com

Attachment - SISA

cc: Kathy Anderson/Orlando Ciniglio

P.O. Box 70 (83707)
1221 W Idaho St.
Boise, ID 83702

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 44

IDAHO POWER®
An IDACORP Company

DRAFT
Generator Interconnection Facility Study Report

for

Salmon Creek 20 MW Wind Project #325 and Jack Ranch 60 MW Wind Project #327

for

Exergy Development Group of Idaho, LLC

in

Twin Falls County, ID

August 11, 2011

DRAFT - FACILITY STUDY REPORT (FSR)

Salmon Creek 20 MW Wind Project #325 and Jack Ranch 60 MW Wind Project #327

August 11, 2011

1.0 General Facility Description

The proposed generation projects consist of 4 (four) 20 MW wind power projects provided by 10 ea. 2.0 MW REPower MM92 generators under four Public Utility Regulatory Policies Act (PURPA) contracts. The location of a new substation owned by the Interconnection Customer would be on private property in the SW1/4 of T14SR16E Section 29 near structures 15-1 and 15-2. The new substation will be the third line terminal on the existing Line #803 Midpoint to Humboldt 345 kV transmission line and will be solely utilized to interconnect the Interconnection Customer to the Idaho Power transmission system.

Interconnection Customer:
Dustin Shively
Exergy Development Group of Idaho, LLC
802 W. Bannock, Suite 1200
Boise, Idaho 83702
dshively@exergydevelopment.com

Standard Generator Interconnection Agreements under Idaho Power Company's Open Access Transmission Tariff (OATT) or Schedule 72 between Interconnection Customers and Idaho Power Company – Delivery (Transmission Owner) for the Salmon Creek 20 MW Wind Project #325 and Jack Ranch 60 MW Wind Project #327, will be prepared for these projects.

A System Impact Re-Study has not been completed for the modifications requested for Jack Ranch 60 MW Wind Project #327; this report does not include any upgrades that may be required by the restudy.

1.1 Interconnection Point

The Interconnection Point for Wind Projects #325 and #327 will be at the customer owned station on the transformer side of the disconnect switch labeled 301B on the single line drawing attached.

1.2 Point of Change of Ownership

The Point of Change of Ownership for Salmon Creek 20 MW Wind Project #325 and Jack Ranch 60 MW Wind Project #327 is electrically the same as the Interconnection Point (note that physically the Interconnection Customer will own or control the substation site where Idaho Power will locate facilities).

1.3 Customer's Interconnection Facilities

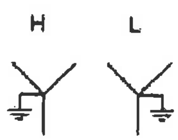
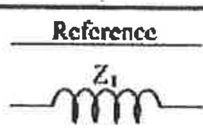
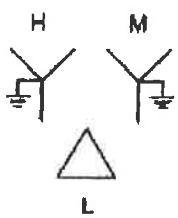
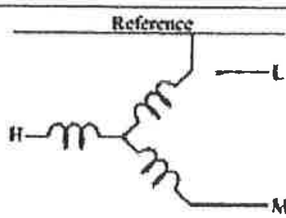
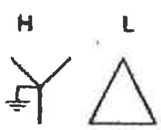
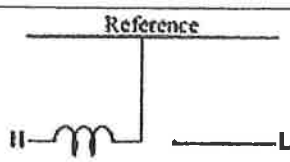
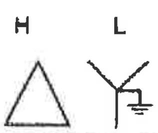
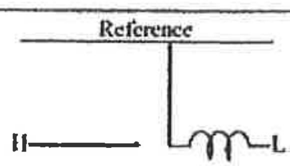
The Interconnection Customer will install generators, step-up transformers, distribution collector system, step-up substation, 34.5 kV to 345 kV transformer and associated auxiliary equipment at the project location connecting the project to the Midpoint – Humboldt 345kV line. The Interconnection Customer will build, own, and maintain facilities electrically located on the Interconnection Customer's side of the Point of Change of Ownership.

1.4 Other Facilities Provided by Interconnection Customer

1.4.1 Ground Fault Equipment

The permissible winding configuration of the interconnect transformer is dependent on the application but shall provide a source of ground current for transmission relaying and the transmission system.

Table 1
Transformer configurations

Transformer Type	Zero-Sequence Connection	Comments
Wye-Grounded Wye-Grounded 		Not a ground source but passes ground current. Independent power producer must supply enough ground current for IPC transmission relaying.
Wye-Grounded Wye-Grounded with Delta Tertiary 		Ground source for transmission relaying.
Wye-Grounded Delta 		Ground source available to transmission relaying. Independent power producer is Delta connected—no ground source.
Delta Wye-Grounded 		No ground source available to transmission relaying. High-side grounding bank required to provide ground current.

1.4.2 Easements

The Interconnection Customer will provide to Idaho Power a surveyed (Metes & Bounds) legal description along with exhibit map for Idaho Power's facilities. After the legal description has been delivered to IPCO for review, IPCO will supply to the Interconnection Customer a completed IPCO easement for signature by the land owner of record. Once the signatures have been secured, the Interconnection Customer will return the signed easement to IPCO for recording.

1.4.3 *Generator Output Limit Control*

The Interconnection Customer will install equipment to receive signals from Idaho Power Grid Operations for Generation Output Limit Control ("GOLC") - see Section 3.0 Operating Requirements.

1.4.4 *Local Service*

The Interconnection Customer is responsible to arrange for local service to the control building for use by the both the Interconnection Customer and Idaho Power.

1.4.5 *Property, Site Work, and Substation Building*

The Interconnection Customer will secure property for the substation and provide access, land clearing, grading, grounding, and fencing for the entire yard (including the Idaho Power side). A building within the substation will be provided by the Interconnection Customer and a separate, lockable room will be allocated inside the building for Idaho Power and NV Energy facilities. The substation will be owned and maintained by the Interconnection Customer. Idaho Power equipment within the Interconnection Customer's yard will be owned and maintained by Idaho Power.

1.5 Idaho Power Company's Interconnection Facilities

Idaho Power will install a short 345 kV transmission tap between the existing Line #803 Midpoint to Humboldt 345 kV transmission line and the Interconnection Customer's owned substation. The tap is assumed to be approximately 600 feet long or less. A dead-end structure, 345 kV circuit breaker, two air-break switches, and associated relaying, control, communication and metering equipment in the substation yard and building up to the Point of Change of Ownership will be installed. See the attached single line drawing.

Idaho Power will install a 34.5kV metering package for each of the four wind parks. They will be overhead or underground equipment as specified by the customer. The primary total metering will be done at 345kV at the substation.

1.6 *Facility Estimated Cost*

The following good faith estimates are provided in 2011 dollars:

Description	Ownership	Cost Estimate
Interconnection Facilities:		
Interconnection Station	IPC	$1,566,000
345 kV Transmission Line Tap	IPC	$207,000
Jack Ranch Metering (1-3)	IPC	$54,000
Salmon Creek Metering	IPC	$18,000
SUBTOTAL		**$1,845,000**

See Section 6 for Project Grand Total

2.0 Milestones

Date	Milestones
TBD	*Construction Funds Received by IPCO*
18 Months after Construction Funds Received by IPCO	*IPCO Construction Complete*
1 month after IPCO Construction Complete	*IPCO Commissioning Complete*
TBD by seller	*Commercial Operation Date*

These milestone dates assume that material can be procured and that outages to the existing transmission line are available to be scheduled. Additionally, any permitting issues outside the immediate control of Idaho Power could also influence the Commercial Operation Date. Idaho Power will continue to work with the Interconnection Customers to take advantage of scheduling efficiencies.

3.0 Operating Requirements

The project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-1992 *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems* or any subsequent standards as they may be updated from time to time.

The Salmon Creek and Jack Ranch Wind Projects will be subject to reductions directed by Idaho Power Grid Operations during transmission system contingencies. When outages occur, the Project will be subject to Generator Output Limit Control ("GOLC") and will have equipment capable of receiving an analog setpoint via DNP 3.0 from Idaho Power for GOLC. Generator Output Limit Control will be a setpoint from Idaho Power to the Project indicating maximum output allowed during transmission contingencies.

Low Voltage Ride Through - The Project must be capable of riding through faults on adjacent section of the power system without tripping due to low voltage. It has been determined, through study, that the Project must be capable of remaining interconnected for any single phase voltage as low as .125 PU for 9 cycles, and for all three phase voltages as low as .11 PU for 3.7 cycles.

Interconnection Customers will be able to modify facilities on the Interconnection Customers' side of the Interconnection Point with no impact upon the operation of the transmission or distribution system whenever the generation facilities are electrically isolated from the system via the 301B airbreak disconnect switch or other approved methods by Idaho Power system operations.

4.0 Reactive Power

To be provided.

5.0 Upgrades Required

5.1 Substation Upgrades

All changes that are made to the line must be designed and maintained in accordance with Idaho Power standards and the WECC standards. Existing WECC criteria require geographic diverse redundant communications paths and redundant or dual primary protection systems.

Idaho Power

- Midpoint – Protective relays will be replaced with IPCo standard SEL421/311L line relay panel. Primary breaker failure will be provided by a second SEL 421 relay.
- Midpoint - Upgrade of the L346 neutral grounding reactor for the line (currently at 32kVA and assumed at 500 kVAr)*
- Midpoint - Replace the existing Wave Trap to match the rating of the line.
- Midpoint – New 3 phase PLC.
- Jack Ranch / Salmon Creek* - A new 100 foot tall communications tower, radio and space diverse antennas would be required as well as reflector on separate site. The primary communications path shall be the establishment of a new Idaho Power owned 6 GHz microwave path from Salmon Creek / Jack Ranch transmitting to a new site such as CMMW.
- CMMW* - A new 100 foot tall communications tower, radio and space diverse antennas would be required.
    - Lower Salmon – install space diverse antennas (A structural analysis has not been accomplished on the existing tower. The tower is assumed to be structurally capable of accepting the new space diverse antennas that would be required. If the tower were found not capable of supporting the new space diverse antennas, a new 100' tower would be required. The LSMW site is an existing site on BLM land, so additional permitting is not anticipated to be required, unless the tower needs to be replaced. If a new tower were required a conditional Use Permit (CUP) would be required from Twin Falls County. Space is available to install the new radio in the existing shelter. A Digital Cross Connect System (DCS) and a larger battery bank and charger would need to be installed.)

NV Energy

- Humboldt - Relaying upgrades will also be required at the NV Energy terminal. They will consist of an SEL-421 and SEL-311L relay for primary protection. Additional relaying to perform breaker failure, back-up protective functions, and control tasks may be required by NV Energy and may not match the relaying specified by Idaho Power for the Midpoint terminal.
- Humboldt – New 3 phase PLC
- CMMW – Microwave addition to IPCo facility
- Ellen D* – New Microwave site

*NOTE: The layout of each of these new communications facilities would be similar to the typical communications site, as shown in Attachment 3. A minimum of 100' x 100' of permitted space would need to be provided by the wind park developer for these communications facilities.

Estimated Costs

The following good faith estimates are provided in 2011 dollars:

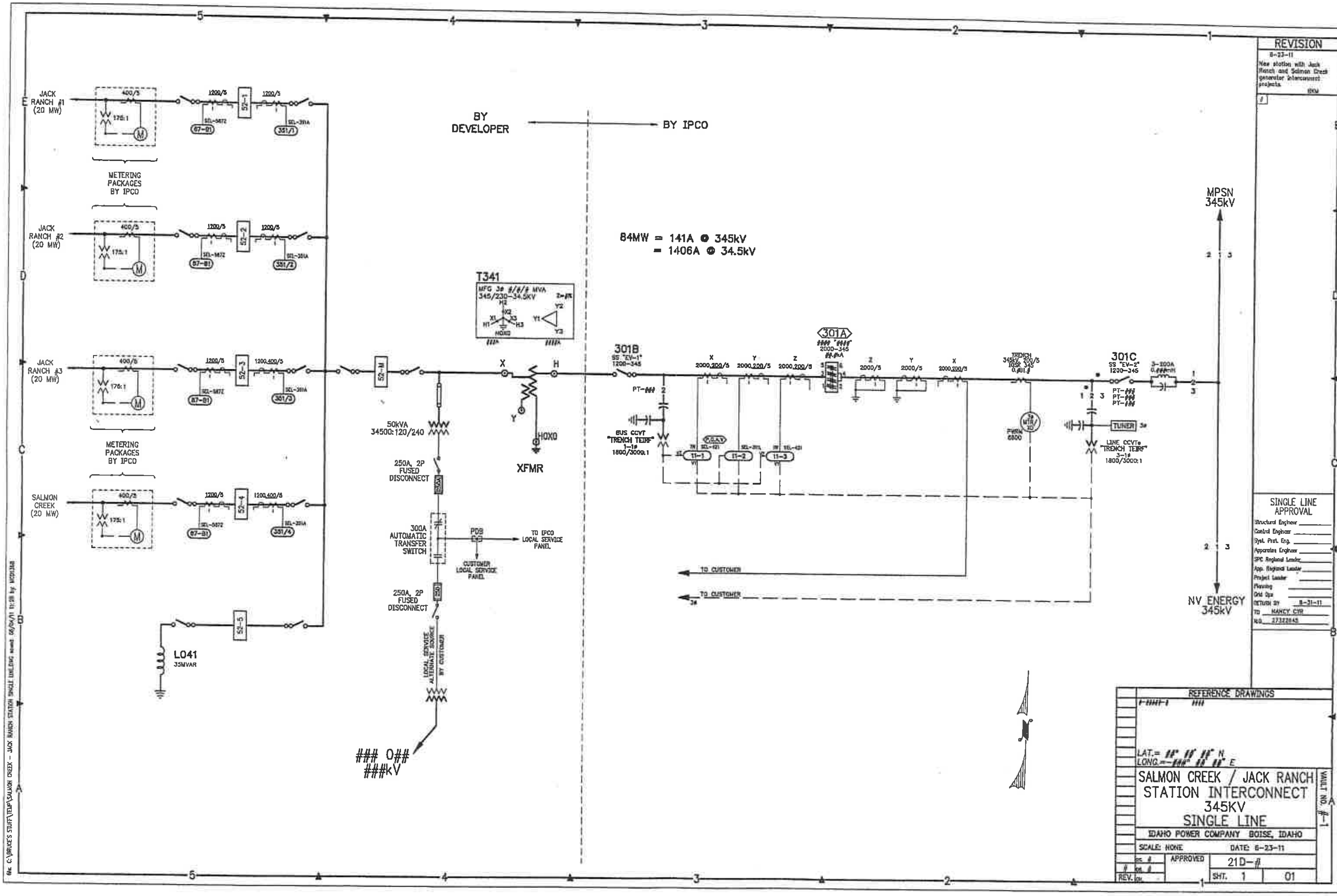
Description	Ownership	Cost Estimate
Interconnection Facilities (from section 1.6):		
Interconnection Station	IPC	$1,566,000
345 kV Transmission Line Tap	IPC	$207,000
Jack Ranch Metering	IPC	$54,000
Salmon Creek Metering	IPC	$18,000
SUBTOTAL		**$1,845,000**
Substation Upgrades:		
Midpoint Protection	IPC	$200,000
Midpoint Neutral Grounding Reactor	IPC	$126,000
Midpoint PLC/ wave trap	IPC	$469,000
Jack Ranch / Salmon Creek Communications	IPC	$767,000
CMMW Communications	IPC	$1,375,000
Lower Salmon Communications	IPC	$387,000
Humboldt Protection	NVE	$351,000
Humboldt PLC	NVE	$286,000
CMMW Communications	NVE	$125,000
Ellen D Communications	NVE	$900,000
SUB TOTAL		**$5,474,000**
GRAND TOTAL		**$7,319,000**

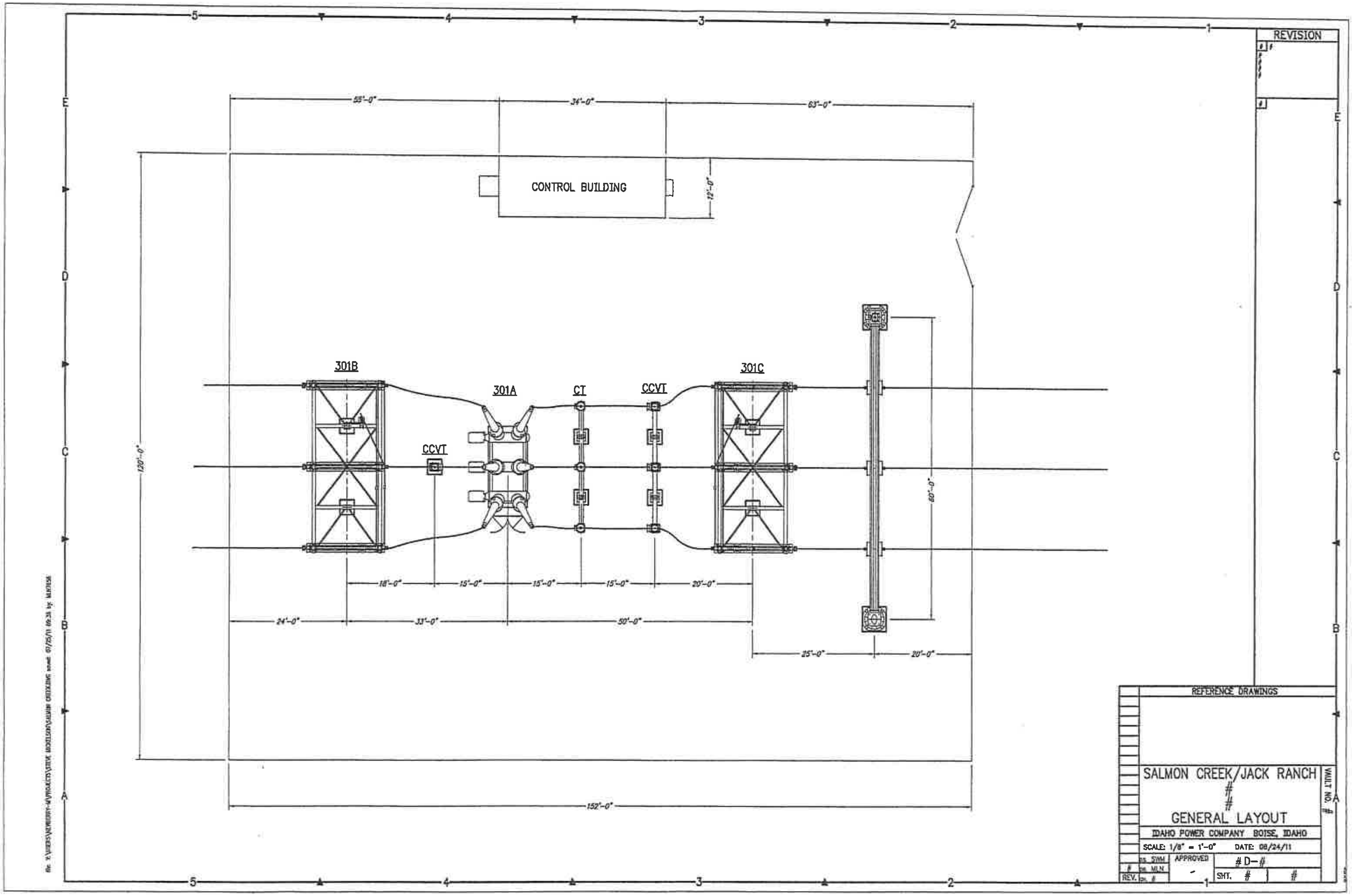
Note Regarding Transmission Service:

This Facility Study is a Network Resource Interconnection Facility Study. This study identifies the facilities necessary to integrate the Generating Facility into Idaho Power's network to serve load within Idaho Power's balancing area. Network Resource Interconnection Service in and of itself does not convey any right to deliver electricity to any specific customer or Point of Delivery.

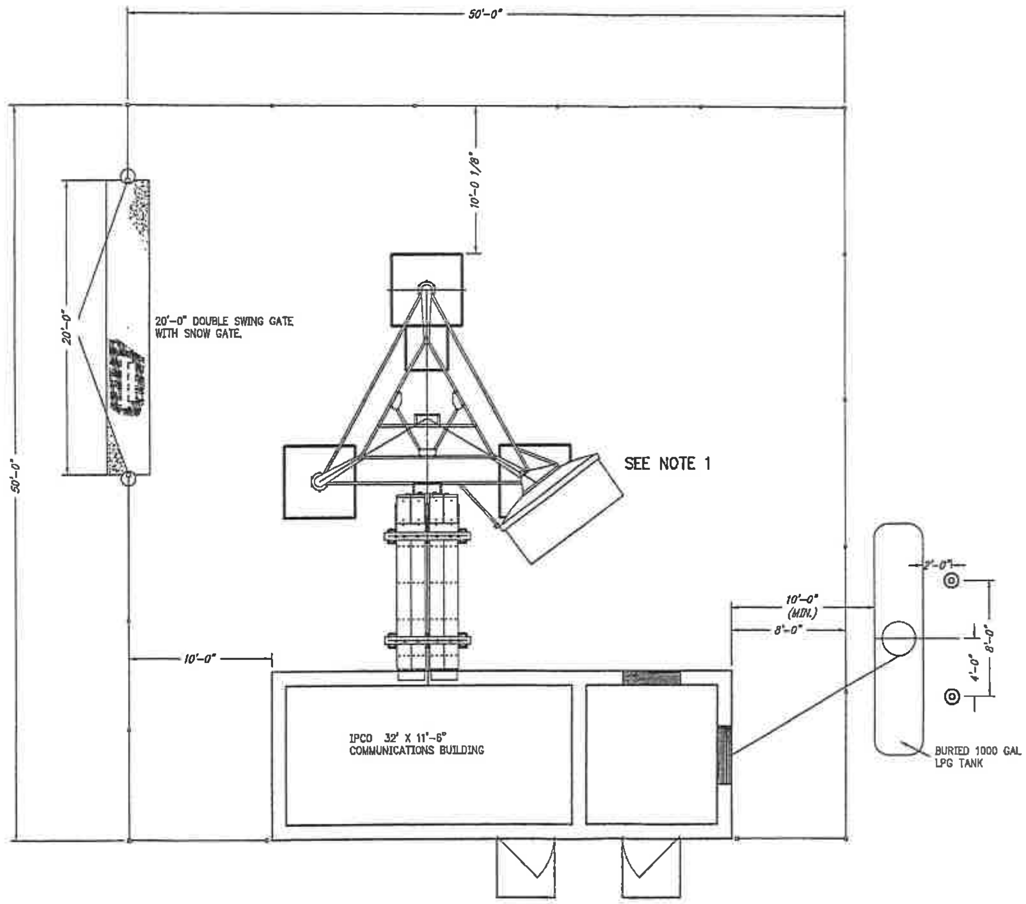
ATTACHMENTS - Drawings

Attachment 1: Salmon Creek/ Jack Ranch Single Line
Attachment 2: Salmon Creek/ Jack Ranch General Location
Attachment 3: Typical Communications Site, General Arrangement


REVISION
8-23-11
New station with Jack Ranch and Salmon Creek generator interconnect projects.
BY DEVELOPER
BY IPCO
JACK RANCH #1 (20 MW)
JACK RANCH #2 (20 MW)
JACK RANCH #3 (20 MW)
SALMON CREEK (20 MW)
METERING PACKAGES BY IPCO
52-1
52-2
52-3
52-4
52-5
52-M
L041
35MVAR
84MW = 141A @ 345kV
= 1406A @ 34.5kV
T341
XFMR
301B
301A
301C
MPSN
345kV
NV ENERGY
345kV
50kVA
34500:120/240
250A, 2P FUSED DISCONNECT
300A AUTOMATIC TRANSFER SWITCH
TO IPCO LOCAL SERVICE PANEL
CUSTOMER LOCAL SERVICE PANEL
LOCAL SERVICE ALTERNATE SOURCE BY CUSTOMER
TO CUSTOMER
TO CUSTOMER
BUS CCVT "TRENCH TEIRF"
LINE CCVTs "TRENCH TEIRF"
TUNER
SINGLE LINE APPROVAL
NANCY CYR
REFERENCE DRAWINGS
SALMON CREEK / JACK RANCH
STATION INTERCONNECT
345KV
SINGLE LINE
IDAHO POWER COMPANY BOISE, IDAHO
SCALE: NONE
DATE: 6-23-11
APPROVED
21D-#
SHT. 1
01
VAULT NO. #-1



REVISION
CONTROL BUILDING
55'-0"
34'-0"
63'-0"
12'-0"
120'-0"
301B
301A
CT
CCVT
CCVT
301C
18'-0"
15'-0"
15'-0"
15'-0"
20'-0"
24'-0"
33'-0"
50'-0"
25'-0"
20'-0"
60'-0"
152'-0"
REFERENCE DRAWINGS
SALMON CREEK/JACK RANCH
GENERAL LAYOUT
VAULT NO.
IDAHO POWER COMPANY BOISE, IDAHO
SCALE: 1/8" = 1'-0"
DATE: 08/24/11
APPROVED
#D-#
SHT.



NOTES:

1. ANTENNA LOCATION ON TOWER AND ORIENTATION OF THE FACILITIES ON PROPOSED SITE STILL TO BE DETERMINED.

REVISION

REFERENCE DRAWINGS

SALMON CREEK/JACK RANCH

GENERAL ARRANGEMENT

IDAHO POWER COMPANY BOISE, IDAHO

SCALE: 1/4" = 1'-0" DATE: 12-11-09

DS. PJC APPROVED # D-#

DR. PJC

REV. CH. # SHT. # #

VAULT NO. #

file: S:\USERS\WEMBERRY-M\PROJECTS\STEVE MICKELSON\SALMON CREEK\COMM BLDG saved: 06/20/11 15:36 by: MLN7656

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 45

IDAHO POWER®
An IDACORP Company

August 17, 2011

Michael Darrington
Senior Planning Analyst

Exergy Development Group of Idaho, LLC
Attention: James Carkulis
802 West Bannock
Ste. 1200
Boise, ID 83702

Original: U.S. Mail

E-mail: jcarkulis@exergydevelopment.com

Re: Transmission Capacity for Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Wind Parks

Mr. James Carkulis:

Transmission Service Request

As you requested, the Power Supply business unit at Idaho Power submitted a request for transmission capacity for the four projects noted above and an additional 4 megawatts (MW) with interconnection on the 345 kV line. At this time we have received a response from the Idaho Power Delivery business unit that a system impact study is required to determine if transmission capacity is available for your projects and if transmission upgrades will be required to enable your project to deliver energy to Idaho Power.

As noted in previous letters and documents provided to you, as a PURPA project your project will be responsible for all costs associated with any required interconnection and/or transmission equipment and upgrades to interconnect and integrate your project's energy deliveries into the Idaho Power electrical system.

The first step in determining any potential required transmission upgrades is to perform a transmission system impact study. The initial deposit required to begin this study is $10,000. Due to the requests from your projects (Cottonwood, Deep Creek, Rogerson Flats, and Salmon Creek Wind Parks) to interconnect and make use of the same transmission path, our transmission group has advised they will be doing a single transmission study for these projects and the additional 4 MW.

P.O. Box 70 (83707)
1221 W. Idaho St.
Boise, ID 83702

The completion of the transmission system impact study will result in identification of required transmission upgrades and estimated cost of those upgrades. At that time an allocation of those costs will be determined based on numerous factors. Some of those cost allocation factors being how many projects elect to proceed and the minimum transmission upgrades required to accommodate the projects.

If you wish for us to proceed with the transmission system impact study for your projects please complete and execute the attached Network Resource Integration Study Agreement, make payment of the required deposit as specified within the agreement and **deliver both** the executed agreement and the required deposit amount to Idaho Power no later than the close of business on **August 23, 2011.** Upon receipt of the executed Network Resource Integration Study Agreement and the required deposit, Idaho Power will execute the same agreement and submit the request to the transmission group to begin the transmission system impact study.

If either the executed Network Resource Integration Study Agreement or the deposit is not received by the date listed above, the initial request for transmission capacity for your project will be withdrawn.

Additionally, please be advised:

The Firm Energy Sales Agreements for each of the projects noted above states:

Appendix B-1 Description of Facility

> "The facility will consist of thirteen 1.6 MW wind turbine generators, with a combined nameplate limited to 20 MW."

Appendix B-4 Maximum Capacity Amount

> "This value will be 20 MW which is consistent with the value provided by the Seller to Idaho Power in accordance with Schedule 72. This value is the maximum energy (MW) that potentially could be delivered by the Seller's Facility to the Idaho Power electrical system at any moment in time."

If you have any questions please do not hesitate to contact me at (208) 388-5946 or mdarrington@idahopower.com.

Sincerely,

Michael Darrington

Michael Darrington

Cc: (IPCo) Donovan Walker
(IPCo) Randy Allphin

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 46

FINAL
Generator Interconnection Facility Study Report

for

Salmon Creek 20 MW Wind Project #325 and
Jack Ranch 60 MW Wind Project #327

for

Exergy Development Group of Idaho, LLC

in

Twin Falls County, ID

December 6, 2011

FINAL - FACILITY STUDY REPORT (FSR)

Salmon Creek 20 MW Wind Project #325 and Jack Ranch 60 MW Wind Project #327

December 6, 2011

1.0 General Facility Description

The proposed generation projects consist of 4 (four) 20 MW wind power projects provided by 10 ea. 2.0 MW Gamesa G97 generators under four Public Utility Regulatory Policies Act (PURPA) contracts. The location of a new substation owned by the Interconnection Customer would be on private property in the SW1/4 of T14SR16E Section 29 near structures 15-1 and 15-2. The new substation will be the third line terminal on the existing Line #803 Midpoint to Humboldt 345 kV transmission line and will be solely utilized to interconnect the Interconnection Customer to the Idaho Power transmission system.

Interconnection Customer:
Dustin Shively
Exergy Development Group of Idaho, LLC
802 W. Bannock, Suite 1200
Boise, Idaho 83702
dshively@exergydevelopment.com

Standard Generator Interconnection Agreements under Idaho Power Company's Open Access Transmission Tariff (OATT) or Schedule 72 between Interconnection Customers and Idaho Power Company – Delivery (Transmission Owner) for the Salmon Creek 20 MW Wind Project #325 and Jack Ranch 60 MW Wind Project #327, will be prepared for these projects.

A System Impact Re-Study has been completed for the modifications requested for Jack Ranch 60 MW Wind Project #327; this report does not require any additional upgrades.

1.1 Interconnection Point

The Interconnection Point for Wind Projects #325 and #327 will be at the customer owned station on the transformer side of the disconnect switch labeled 301B on the single line drawing attached.

1.2 Point of Change of Ownership

The Point of Change of Ownership for Salmon Creek 20 MW Wind Project #325 and Jack Ranch 60 MW Wind Project #327 is electrically the same as the Interconnection Point (note that physically the Interconnection Customer will own or control the substation site where Idaho Power will locate facilities).

1.3 Customer's Interconnection Facilities

The Interconnection Customer will install generators, step-up transformers, distribution collector system, step-up substation, 34.5 kV to 345 kV transformer and associated auxiliary equipment at the project location connecting the project to the Midpoint – Humboldt 345kV line. The Interconnection Customer will build, own, and maintain facilities electrically located on the Interconnection Customer's side of the Point of Change of Ownership.

1.4 Other Facilities Provided by Interconnection Customer

1.4.1 Telecommunications

In addition to communication circuits that may be needed by the Interconnection Customer, the Interconnection Customer shall provide the following communication circuits for Idaho Power's use:

1. One POTS (Plain Old Telephone Service) dial-up circuit for querying the revenue meter at the generation interconnection site.
2. One data circuit (guaranteed minimum data rate of 19,200 bits per second) for SCADA between the generation interconnection site and IPC's Boise Bench facility. The data circuit type shall be one of the following types:
    a. DDS (Digital Data Service). Please note that Frame Relay Service is not acceptable.
    b. 4-wire voice grade analog data circuit (e.g. Qwest VG36)
3. One data circuit (guaranteed minimum data rate of 19,200 bits per second) for each required Phasor Measurement Unit (PMU) between the generation interconnection site and IPC's Boise Bench facility. The data circuit type shall be one of the following types:
    a. DDS (Digital Data Service). Please note that Frame Relay Service is not acceptable.
    b. 4-wire voice grade analog data circuit (e.g. Qwest VG36)

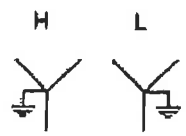
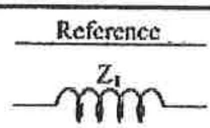
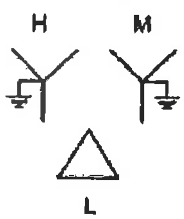
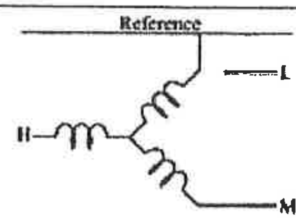
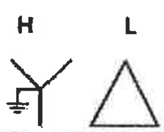
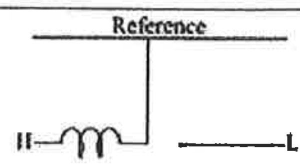
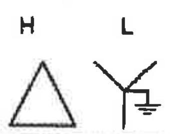
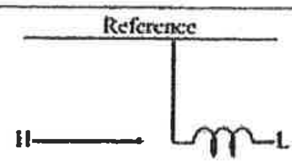
The Interconnection Customer is required to coordinate with a communications provider to provide the communications circuits and pay the associated one time setup and periodic charges. The communication circuits will need to be installed and operational prior to generating into the Idaho Power system. Note that installation by communications provider may take several months and should be ordered in advance to avoid delaying the project. If the communication circuit types listed above are not available at the site by a communications provider, the Interconnection Customer shall confer with Idaho Power.

If high voltage protection is required by the communications provider for the incoming communications provider cable, the high voltage protection assembly shall be engineered and supplied by the Interconnect Customer. Options are available for indoor or outdoor mounting. The high voltage protection assembly shall be located in a manner that provides Idaho Power 24-hour access to the assembly for trouble-shooting of Idaho Power owned equipment.

1.4.2 Ground Fault Equipment

The permissible winding configuration of the interconnect transformer is dependent on the application but shall provide a source of ground current for transmission relaying and the transmission system.

Table 1
Transformer configurations

Transformer Type	**Zero-Sequence Connection**	**Comments**
Wye-Grounded Wye-Grounded 		Not a ground source but passes ground current. Independent power producer must supply enough ground current for IPC transmission relaying.
Wye-Grounded Wye-Grounded with Delta Tertiary 		Ground source for transmission relaying.
Wye-Grounded Delta 		Ground source available to transmission relaying. Independent power producer is Delta connected—no ground source.
Delta Wye-Grounded 		No ground source available to transmission relaying. High-side grounding bank required to provide ground current.

1.4.3 Easements

The Interconnection Customer will provide to Idaho Power a surveyed (Metes & Bounds) legal description along with exhibit map for Idaho Power's facilities. After the legal description has been delivered to IPCO for review, IPCO will supply to the Interconnection Customer a completed IPCO easement for signature by the land owner of record. Once the signatures have been secured, the Interconnection Customer will return the signed easement to IPCO for recording.

1.4.4 Generator Output Limit Control

The Interconnection Customer will install equipment to receive signals from Idaho Power Grid Operations for Generation Output Limit Control ("GOLC") - see Section 3.0 Operating Requirements.

1.4.5 Local Service

The Interconnection Customer is responsible to arrange for local service to the control building for use by the both the Interconnection Customer and Idaho Power.

1.4.6 Property, Site Work, and Substation Building

The Interconnection Customer will secure property for the substation and provide access, land clearing, grading, grounding, and fencing for the entire yard (including the Idaho Power side). A building within the substation will be provided by the Interconnection Customer and a separate, lockable room will be allocated inside the building for Idaho Power and NV Energy facilities. The substation will be owned and maintained by the Interconnection Customer. Idaho Power equipment within the Interconnection Customer's yard will be owned and maintained by Idaho Power.

1.4.7 Meteorological Data

In order to integrate the wind energy into the Idaho Power system, the Interconnection Customer will provide weather data to IPCO from the proposed Facility Site or from a location within two miles of the Facility site consisting of the following instantaneous weather parameters that will be collected via each meteorological observation tower at 10m & 80m above ground: Wind Speed(m/s), Wind Direction, Air Temperature (degrees Cent), along with Relative Humidity, and Barometric Pressure. This data shall be provided to IPCo hourly via commonly accepted electronic web service standards or similar communication method. The Customer will provide relevant historical meteorological data to IPC. Additionally, the Customer shall submit to Idaho Power the physical and technical specifications for all meteorological measurement devices, geographic locations and technical specifications of all turbines. The associated cost for obtaining this data is the Customers responsibility and therefore not included in the Facility Study estimate.

1.5 Idaho Power Company's Interconnection Facilities

Idaho Power will install a short 345 kV transmission tap between the existing Line #803 Midpoint to Humboldt 345 kV transmission line and the Interconnection Customer's owned substation. The tap is assumed to be approximately 600 feet long or less. A dead-end structure, 345 kV circuit breaker, two air-break switches, and associated relaying, control, communication and metering equipment in the substation yard and building up to the Point of Change of Ownership will be installed. See the attached single line drawing.

Idaho Power will install a 34.5kV metering package for each of the four wind parks. They will be overhead or underground equipment as specified by the customer. The primary total metering will be done at 345kV at the substation.

1.6 *Facility Estimated Cost*

The following good faith estimates are provided in 2011 dollars:

Description	Ownership	Cost Estimate
Interconnection Facilities:		
Interconnection Station	IPC	$2,074,000
345 kV Transmission Line Tap	IPC	$185,000
Jack Ranch Metering (1-3)	IPC	$54,000
Salmon Creek Metering	IPC	$18,000
SUBTOTAL		**$2,331,000**
See Section 6 for Project Grand Total		

2.0 Milestones

Date	Milestones
TBD	*Construction Funds Received by IPCO*
18 Months after Construction Funds Received by IPCO	*IPCO Construction Complete*
1 month after IPCO Construction Complete	*IPCO Commissioning Complete*
TBD by seller	*Commercial Operation Date*

These milestone dates assume that material can be procured and that outages to the existing transmission line are available to be scheduled. Additionally, any permitting issues outside the immediate control of Idaho Power could also influence the Commercial Operation Date. Idaho Power will continue to work with the Interconnection Customers to take advantage of scheduling efficiencies.

3.0 Operating Requirements

The project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-1992 *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems* or any subsequent standards as they may be updated from time to time.

The Salmon Creek and Jack Ranch Wind Projects will be subject to reductions directed by Idaho Power Grid Operations during transmission system contingencies. When outages occur, the Project will be subject to Generator Output Limit Control ("GOLC") and will have equipment capable of receiving an analog setpoint via DNP 3.0 from Idaho Power for GOLC. Generator Output Limit Control will be a setpoint from Idaho Power to the Project indicating maximum output allowed during transmission contingencies. For detailed information refer to Attachment 4.

Low Voltage Ride Through - The Project must be capable of riding through faults on adjacent section of the power system without tripping due to low voltage. It has been determined, through study, that the Project must be capable of remaining interconnected for any single phase voltage as low as .125 PU for 9 cycles, and for all three phase voltages as low as .11 PU for 3.7 cycles.

Interconnection Customers will be able to modify facilities on the Interconnection Customers' side of the Interconnection Point with no impact upon the operation of the transmission or distribution system whenever the generation facilities are electrically isolated from the system via the 301B airbreak disconnect switch or other approved methods by Idaho Power system operations.

4.0 Reactive Power

The Project must be capable of +/- 0.95 power factor operation, as measured at the Interconnection Point, for all MW production levels from zero MW output to full rated MW output. The Project must have equipment capable of receiving an analog setpoint, via DNP 3.0 from Idaho Power for voltage setpoint. The setpoint will be the desired voltage level as measured at the interconnect bus. The range of setpoint will be 345.00 kV to 362.25 kV.

5.0 Upgrades Required

5.1 Substation Upgrades

All changes that are made to the line must be designed and maintained in accordance with Idaho Power standards and the WECC standards. Existing WECC criteria require geographic diverse redundant communications paths and redundant or dual primary protection systems.

Idaho Power

- Midpoint – Protective relays will be replaced with IPCo standard SEL421/311L line relay panel. Primary breaker failure will be provided by a second SEL 421 relay.
- Midpoint - Upgrade of the L346 neutral grounding reactor for the line (currently at 32kVA and assumed at 500 kVAr)*
- Midpoint - Replace the existing Wave Trap to match the rating of the line.
- Midpoint – New 3 phase PLC.
- Jack Ranch / Salmon Creek* - A new 100 foot tall communications tower, radio and space diverse antennas would be required as well as reflector on separate site. The primary communications path shall be the establishment of a new Idaho Power owned 6 GHz microwave path from Salmon Creek / Jack Ranch transmitting to a new site such as CMMW.
- CMMW* - A new 100 foot tall communications tower, radio and space diverse antennas would be required.
    - Lower Salmon – install space diverse antennas (A structural analysis has not been accomplished on the existing tower. The tower is assumed to be structurally capable of accepting the new space diverse antennas that would be required. If the tower were found not capable of supporting the new space diverse antennas, a new 100' tower would be required. The LSMW site is an existing site on BLM land, so additional permitting is not anticipated to be

required, unless the tower needs to be replaced. If a new tower were required a conditional Use Permit (CUP) would be required from Twin Falls County. Space is available to install the new radio in the existing shelter. A Digital Cross Connect System (DCS) and a larger battery bank and charger would need to be installed.)

NV Energy

- Humboldt - Relaying upgrades will also be required at the NV Energy terminal. They will consist of an SEL-421 and SEL-311L relay for primary protection. Additional relaying to perform breaker failure, back-up protective functions, and control tasks may be required by NV Energy and may not match the relaying specified by Idaho Power for the Midpoint terminal.
- Humboldt – New 3 phase PLC
- CMMW – Microwave addition to IPCo facility
- Ellen D* – New Microwave site

*NOTE: The layout of each of these new communications facilities would be similar to the typical communications site, as shown in Attachment 3. A minimum of 100' x 100' of permitted space would need to be provided by the wind park developer for these communications facilities.

Estimated Costs

The following good faith estimates are provided in 2011 dollars:

Description	Ownership	Cost Estimate
Interconnection Facilities (from section 1.6):		
Interconnection Station	IPC	$2,074,000
345 kV Transmission Line Tap	IPC	$185,000
Jack Ranch Metering	IPC	$54,000
Salmon Creek Metering	IPC	$18,000
SUBTOTAL		**$2,331,000**
Substation Upgrades:		
Midpoint Protection	IPC	$200,000
Midpoint Neutral Grounding Reactor	IPC	$126,000
Midpoint PLC/ wave trap	IPC	$473,000
Jack Ranch / Salmon Creek Communications	IPC	$767,000
Jack Ranch / Salmon Creek PLC	IPC	$526,000
CMMW Communications	IPC	$1,375,000
Lower Salmon Communications	IPC	$387,000
Humboldt Protection	NVE	$351,000
Humboldt PLC	NVE	$286,000
CMMW Communications	NVE	$125,000
Ellen D Communications	NVE	$900,000
SUB TOTAL		**$5,516,000**
GRAND TOTAL		**$7,847,000**

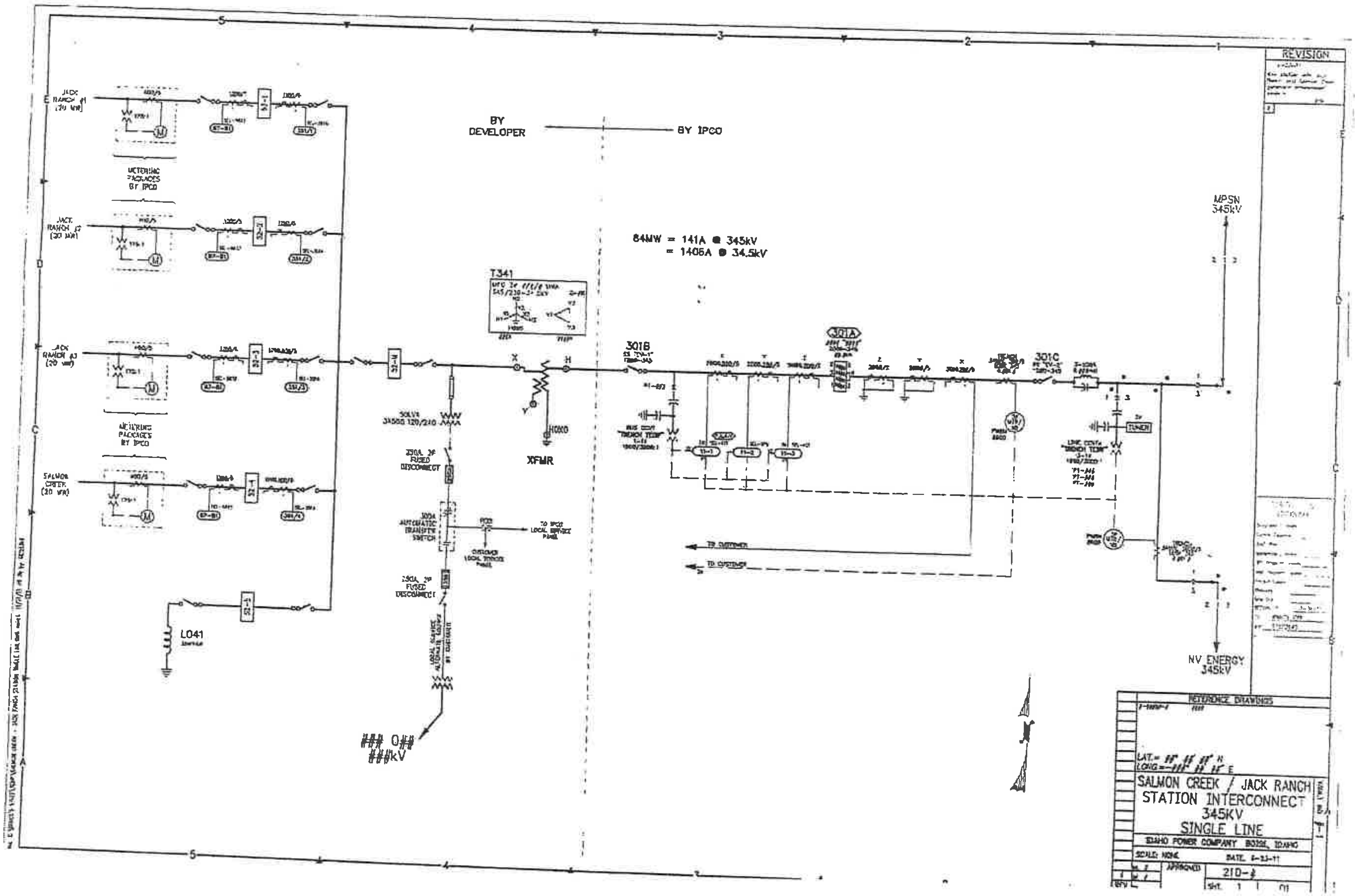
Note Regarding Transmission Service:

This Facility Study is a Network Resource Interconnection Facility Study. This study identifies the facilities necessary to integrate the Generating Facility into Idaho Power's network to serve load within Idaho Power's balancing area. Network Resource Interconnection Service in and of itself does not convey any right to deliver electricity to any specific customer or Point of Delivery.

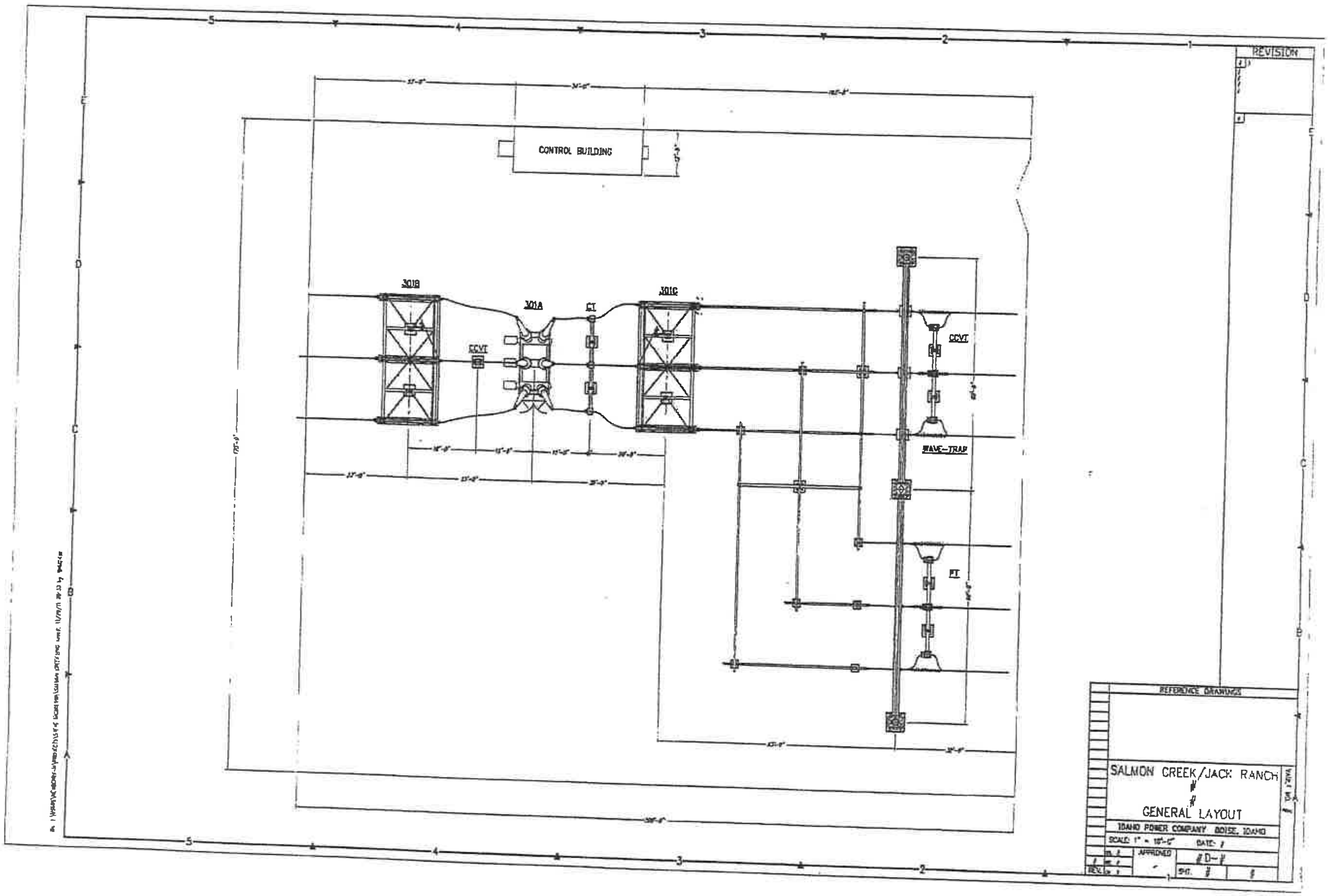
ATTACHMENTS

Attachment 1: Salmon Creek/ Jack Ranch Single Line
Attachment 2: Salmon Creek/ Jack Ranch General Location
Attachment 3: Typical Communications Site, General Arrangement
Attachment 4: Generation Interconnection Control & Data Point Requirements

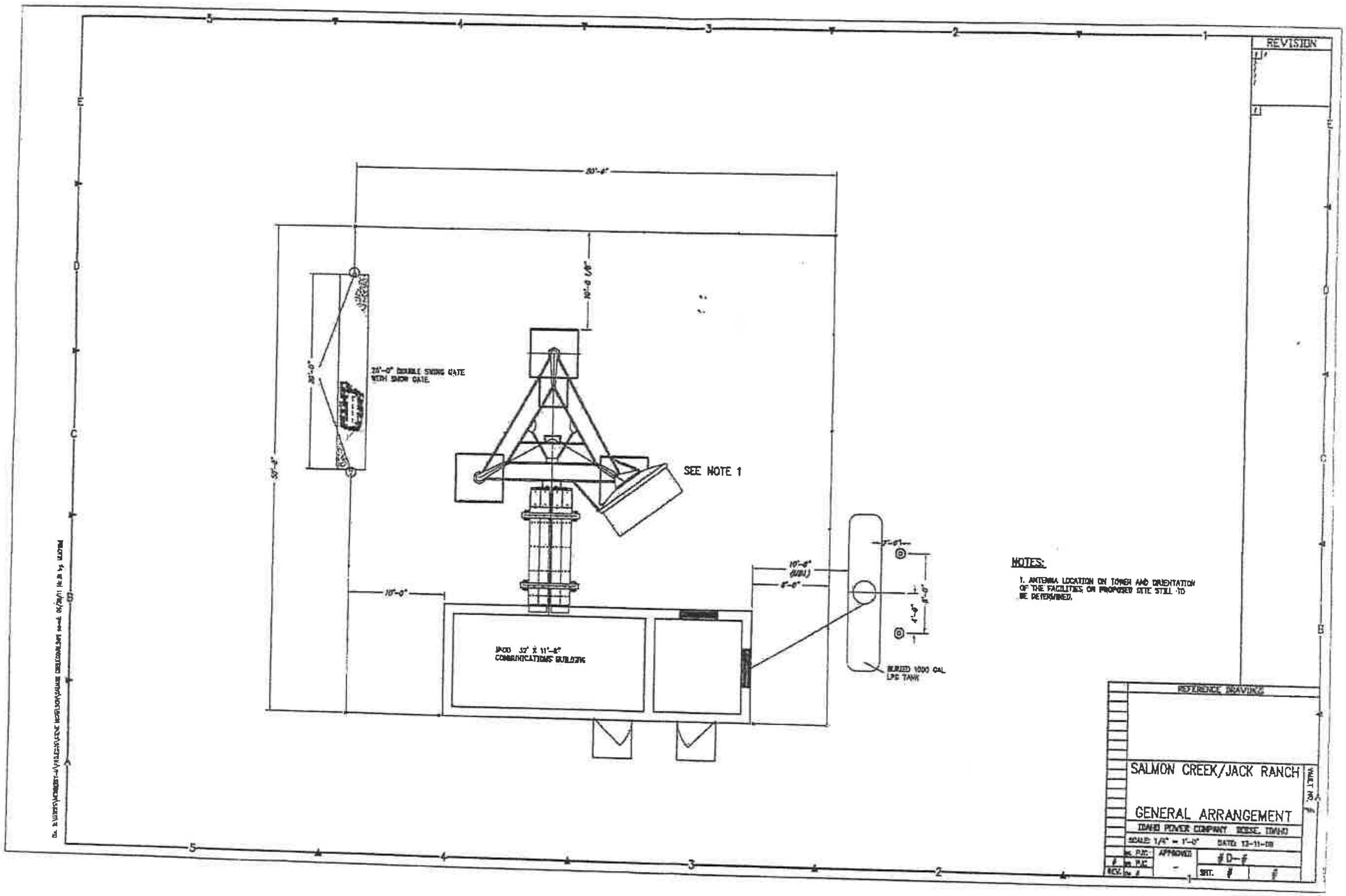
Attachment 1



Attachment 2



Attachment 3



Attachment 4

Generation Interconnection Control Requirements

Generator Output Limit Control (GOLC)

- IPC requires Interconnected Power Producers to accept GOLC signals from our EMS.
- The GOLC signals will consist of two points shared between the IPC EMS and the Customer's Generator Controller:
  1. GOLC Setpoint: An analog output that contains the MW value the Customer should curtail to, should a GOLC request be made via the GOLC On/Off discrete output Control point.
     - An Analog Input feedback point must be updated (to reflect the GOLC setpoint value) by the Customer Controller upon the Controller's receipt of the GOLC setpoint change, with no intentional delay.
  2. GOLC On/Off: A discrete output (DO) control point with latching Off/On states. Following a "GOLC On" control, the Customer Controller will run power output back to the MW value specified in the GOLC Setpoint. Following a "GOLC Off" control, the Customer is free to run to maximum possible output.
     - A Discrete Input feedback point must be updated (to reflect the GOLC DO state) by the Customer Controller upon the Controller's receipt of the GOLC DO state change, with no intentional delay.
- If a GOLC control is issued, it is expected to see MW reductions start within 1 minute and plant output to be below the GOLC Setpoint value within 10 minutes.

Voltage Control

- IPC requires Interconnected Power Producers to accept Voltage Control signals from our EMS when they are connected to our transmission system.
- The voltage control will consist of one setpoint shared between the IPC EMS and the Customer Controller.
- The setpoint will contain the desired target voltage for the plant to operate at.
- The control will always be active, there is no digital supervisory point like the Curtail On/Off control above.
  - When a setpoint change is issued an Analog Input feedback point must be updated (to reflect the Voltage Control setpoint value) by the Customer Controller upon the Controller's receipt of the Voltage Control setpoint change, with no intentional delay.
  - When a setpoint change is received by the Customer Controller, the Voltage Control system should react with no intentional delay.
  - The voltage control system should operate in a dead band of +/-5% of the control setting range.
- The wind parks should supervise this control by setting up "reasonability limits", i.e. configure a reasonable range of values for this control to be valid. As an example, they will accept anything between .95 and 1.05 for the set point. In the case they are fed an erroneous value outside this range, their control system defaults to the last known, good value.

Generation Interconnection Data Points Requirements

Digital Inputs (DNP Obj. 01, Var. 2)			
Index	Description	State (0/1)	Comments:
0	52A Customer Total Breaker	Open/Closed	Sourced at substation
1	GOLC Off/On Control Received (Feedback)	Off/On	Provided by Customer

Digital Outputs (DNP Obj. 10, Var. 1)		
Index	Description	Comments:
0	GOLC Off/On	Provided by IPCO
	NOTE: GOLC Setpoint indicates MW value to curtail to when GOLC Off/On DO is ON.	

Analog Inputs (DNP Obj. 30, Var. 2)							
Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
0	GOLC Setpoint Value Received (Feedback)	32767	-32768	TBD	TBD	MW	Provided by Customer
1	Voltage Control Setpoint Value Rec'd (Feedback)	32767	-32768	TBD	TBD	kV	Provided by Customer

2	Maximum Park Generating Capacity*	32767	-32768	TBD	TBD	MW	Provided by Customer
3	Number of Turbines In High Speed Cutout*	32767	-32768	32767	-32768	Units	Provided by Customer
4	Ambient Temperature*	32767	-32768	327.67	-327.68	F or C	Provided by Customer
5	Wind Direction*	32767	-32768	3276.7	-3276.8	Deg	Provided by Customer
6	Wind Speed*	32767	-32768	327.67	-327.68	MPH or m/s	Provided by Customer

Analog Outputs (DNP Obj. 40, Var. 2)

Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
0	GOLC Setpoint	32767	-32768	TBD	TBD	MW	Provided by IPCO
1	Voltage Control Setpoint	32767	-32768	TBD	TBD	kV	Provided by IPCO
	NOTE: Curtailment Setpoint indicates MW value to Curtail to when Curtailment Off/On DO is ON.						

* - Data required from Wind Customers

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 47

Dec 15, 2011

GENERATOR INTERCONNECTION AGREEMENT
Schedule 72

SALMON CREEK/JACK RANCH WIND PROJECT
80 MW

TABLE OF CONTENTS

This Generator Interconnection Agreement ("Agreement") under Idaho Power Company's Schedule 72 is effective as of the ____ day of __________, 2011 between ____________________________, ("Seller" or "The Project") and Idaho Power Company – Delivery ("Company", or "Transmission Owner").

RECITALS

A. Seller will own or operate a Generation Facility that qualifies for service under Idaho Power's Commission-approved Schedule 72 and any successor schedule.

B. The Generation Facility covered by this Agreement is more particularly described in Attachment 1.

AGREEMENTS

1. Capitalized Terms
Capitalized terms used herein shall have the same meanings as defined in Schedule 72 or in the body of this Agreement.

2. Terms and Conditions
This Agreement and Schedule 72 provide the rates, charges, terms and conditions under which the Seller's Generation Facility will interconnect with, and operate in parallel with, the Company's transmission/distribution system. Terms defined in Schedule 72 will have the same defined meaning in this Agreement. If there is any conflict between the terms of this Agreement and Schedule 72, Schedule 72 shall prevail.

3. This Agreement is not an agreement to purchase Seller's power.
Purchase of Seller's power and other services that Seller may require will be covered under separate agreements. Nothing in this Agreement is intended to affect any other agreement between the Company and Seller.

4. Attachments
Attached to this Agreement and included by reference are the following:

Attachment 1 – Description and Costs of the Generation Facility, Interconnection Facilities, and Metering Equipment.

Attachment 2 – One-line Diagram Depicting the Generation Facility, Interconnection Facilities, Metering Equipment and Upgrades.

Attachment 3 – Milestones For Interconnecting the Generation Facility.

Attachment 4 – Additional Operating Requirements for the Company's Transmission System Needed to Support the Seller's Generation Facility.

Attachment 5 – Reactive Power.

Attachment 6 – Description of Upgrades required to integrate the Generation Facility and Best Estimate of Upgrade Costs.

5. Effective Date, Term, Termination and Disconnection.

5.1 Term of Agreement. Unless terminated earlier in accordance with the provisions of this Agreement, this Agreement shall become effective on the date specified above and remain effective as long as Seller's Generation Facility is eligible for service under Schedule 72.

5.2 Termination.

5.2.1 Seller may voluntarily terminate this Agreement upon expiration or termination of an agreement to sell power to the Company.

5.2.2 After a Default, either Party may terminate this Agreement pursuant to Section 6.5.

5.2.3 Upon termination or expiration of this Agreement, the Seller's Generation Facility will be disconnected from the Company's transmission/distribution system. The termination or expiration of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination. The provisions of this Section shall survive termination or expiration of this Agreement.

5.3 Temporary Disconnection. Temporary disconnection shall continue only for so long as reasonably necessary under "Good Utility Practice." Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region. Good Utility Practice includes compliance with WECC or NERC requirements. Payment of lost revenue resulting from temporary disconnection shall be governed by the power purchase agreement.

5.3.1 Emergency Conditions. "Emergency Condition" means a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of the Company, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Company's transmission/distribution system, the Company's Interconnection Facilities or the equipment of the Company's customers; or (3) that, in the case of the Seller, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the reliability and security of, or damage to, the Generation Facility or the Seller's Interconnection Facilities. Under Emergency Conditions, either the Company or the Seller may immediately suspend interconnection service and temporarily disconnect the Generation Facility. The Company shall notify the Seller promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Seller's operation of the Generation Facility. The Seller shall notify the Company promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Company's equipment or service to the Company's customers. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of both Parties' facilities and operations, its anticipated duration, and the necessary corrective action.

5.3.2 Routine Maintenance, Construction, and Repair. The Company may interrupt interconnection service or curtail the output of the Seller's Generation Facility *and temporarily disconnect the Generation Facility from the Company's transmission/distribution system when necessary for routine maintenance, construction, and repairs on the Company's transmission/distribution system. The Company will make a reasonable attempt to contact the Seller prior to exercising its rights to interrupt interconnection or curtail deliveries from the Seller's Facility. Seller understands that in the case of emergency circumstances, real time operations of the electrical system, and/or unplanned events, the Company may not be able to provide notice to the Seller prior to interruption, curtailment or reduction of electrical energy deliveries to the Company. The Company shall use reasonable efforts to coordinate such reduction or temporary disconnection with the Seller.*

5.3.3 Scheduled Maintenance. On or before January 31 of each calendar year, Seller shall submit a written proposed maintenance schedule of significant Facility maintenance for that calendar year and the Company and Seller shall mutually agree as to the acceptability of the proposed schedule. The Parties determination as to the acceptability of the Seller's timetable for scheduled maintenance will take into consideration Good Utility Practices, Idaho Power system requirements and the Seller's preferred schedule. Neither Party shall unreasonably withhold acceptance of the proposed maintenance schedule.

5.3.4. Maintenance Coordination. The Seller and the Company shall, to the extent practical, coordinate their respective transmission/distribution system and Generation Facility maintenance schedules such that they occur simultaneously. Seller shall provide and maintain adequate protective equipment sufficient to prevent damage to the Generation Facility and Seller-furnished Interconnection Facilities. In some cases, some of Seller's protective relays will provide back-up protection for Idaho Power's facilities. In that event, Idaho Power will test such relays annually and Seller will pay the actual cost of such annual testing.

5.3.5 Forced Outages. During any forced outage, the Company may suspend interconnection service to effect immediate repairs on the Company's transmission/distribution system. The Company shall use reasonable efforts to provide the Seller with prior notice. If prior notice is not given, the Company shall, upon request, provide the Seller written documentation after the fact explaining the circumstances of the disconnection.

5.3.6 Adverse Operating Effects. The Company shall notify the Seller as soon as practicable if, based on Good Utility Practice, operation of the Seller's Generation Facility may cause disruption or deterioration of service to other customers served from the same electric system, or if operating the Generation Facility could cause damage to the Company's transmission/distribution system or other affected systems. Supporting documentation used to reach the decision to disconnect shall be provided to the Seller upon request. If, after notice, the Seller fails to remedy the adverse operating effect within a reasonable time, the Company may disconnect the Generation Facility. The Company shall provide the Seller with reasonable notice of such disconnection, unless the provisions of Article 5.3.1 apply.

5.3.7 Modification of the Generation Facility. The Seller must receive written authorization from the Company before making any change to the Generation Facility that may have a material impact on the safety or reliability of the Company's transmission/distribution system. Such authorization shall not be unreasonably withheld. Modifications shall be done in accordance with Good Utility Practice. If the Seller makes such modification without the Company's prior written authorization, the latter shall have the right to temporarily disconnect the Generation Facility.

5.3.8 <u>Reconnection.</u> The Parties shall cooperate with each other to restore the Generation Facility, Interconnection Facilities, and the Company's transmission/distribution system to their normal operating state as soon as reasonably practicable following a temporary disconnection.

5.3.9 <u>Voltage Levels.</u> Seller, in accordance with Good Utility Practices, shall minimize voltage fluctuations and maintain voltage levels acceptable to Idaho Power. Idaho Power may, in accordance with Good Utility Practices, upon one hundred eighty (180) days' notice to the Seller, change its nominal operating voltage level by more than ten percent (10%) at the Point of Delivery, in which case Seller shall modify, at Idaho Power's expense, Seller's equipment as necessary to accommodate the modified nominal operating voltage level.

5.4 <u>Land Rights.</u>

5.4.1 <u>Seller to Provide Access.</u> Seller hereby grants to Idaho Power for the term of this Agreement all necessary rights-of-way and easements to install, operate, maintain, replace, and remove Idaho Power's Metering Equipment, Interconnection Equipment, Disconnection Equipment, Protection Equipment and other Special Facilities necessary or useful to this Agreement, including adequate and continuing access rights on property of Seller. Seller warrants that it has procured sufficient easements and rights-of-way from third parties so as to provide Idaho Power with the access described above. All documents granting such easements or rights-of-way shall be subject to Idaho Power's approval and in recordable form.

5.4.2 <u>Use of Public Rights-of-Way.</u> The Parties agree that it is necessary to avoid the adverse environmental and operating impacts that would occur as a result of duplicate electric lines being constructed in close proximity. Therefore, subject to Idaho Power's compliance with Paragraph 5.4.4, Seller agrees that should Seller seek and receive from any local, state or federal governmental body the right to erect, construct and maintain Seller-furnished Interconnection Facilities upon, along and over any and all public roads, streets and highways, then the use by Seller of such public right-of-way shall be subordinate to any future use by Idaho Power of such public right-of-way for construction and/or maintenance of electric distribution and transmission facilities and Idaho Power may claim use of such public right-of-way for such purposes at any time. Except as required by Paragraph 5.4.4, Idaho Power shall not be required to compensate Seller for exercising its rights under this Paragraph 5.4.2.

5.4.3 <u>Joint Use of Facilities.</u> Subject to Idaho Power's compliance with Paragraph 15.4.4, Idaho Power may use and attach its distribution and/or transmission facilities to Seller's Interconnection Facilities, may reconstruct Seller's Interconnection Facilities to accommodate Idaho Power's usage or Idaho Power may construct its own distribution or transmission facilities along, over and above any public right-of-way acquired from Seller pursuant to Paragraph 5.4.2, attaching Seller's Interconnection Facilities to such newly constructed facilities. Except as required by Paragraph 5.4.4, Idaho Power shall not be required to compensate Seller for exercising its rights under this Paragraph 5.4.3.

5.4.4 <u>Conditions of Use.</u> It is the intention of the Parties that the Seller be left in substantially the same condition, both financially and electrically, as Seller existed prior to Idaho Power's exercising its rights under this Paragraph 5.4. Therefore, the Parties agree that the exercise by Idaho Power of any of the rights enumerated in Paragraphs

5.4.2 and 5.4.3 shall: (1) comply with all applicable laws, codes and Good Utility Practices, (2) equitably share the costs of installing, owning and operating jointly used facilities and rights-of-way. If the Parties are unable to agree on the method of apportioning these costs, the dispute will be submitted to the Commission for resolution and the decision of the Commission will be binding on the Parties, and (3) shall provide Seller with an interconnection to Idaho Power's system of equal capacity and durability as existed prior to Idaho Power exercising its rights under this Paragraph 5.4.

6. Assignment, Liability, Indemnity, Force majeure, Consequential Damages and Default.

6.1 Assignment. This Agreement may be assigned by either Party upon twenty-one (21) calendar days prior written notice and opportunity to object by the other Party; provided that:

6.1.1 Either Party may assign this Agreement without the consent of the other Party to any affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement.

6.1.2 The Seller shall have the right to contingently assign this Agreement, without the consent of the Company, for collateral security purposes to aid in providing financing for the Generation Facility, provided that the Seller will promptly notify the Company of any such contingent assignment.

6.1.3 Any attempted assignment that violates this article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same financial, credit, and insurance obligations as the Seller. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

6.2 Limitation of Liability. Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages, except as authorized by this Agreement.

6.3 Indemnity.

6.3.1 This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in Article 6.2.

6.3.2 The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

6.3.3 If an indemnified person is entitled to indemnification under this article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this article, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, *settle or consent to the entry of any judgment with respect to, or pay in full, such claim. Failure to defend is a Material Breach.*

6.3.4 If an indemnifying party is obligated to indemnify and hold any indemnified person harmless under this article, the amount owing to the indemnified person shall be the amount of such indemnified person's actual loss, net of any insurance or other recovery.

6.3.5 Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this article may apply, the indemnified person shall notify the indemnifying party of such fact. Any failure of or delay in such notification shall be a Material Breach and shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party.

6.4 Force Majeure. As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the control of the Seller or of the Company which, despite the exercise of due diligence, such Party is unable to prevent or overcome. Force Majeure includes, but is not limited to, acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, or changes in law or regulation occurring after the Operation Date, which, by the exercise of reasonable foresight such party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome. If either Party is rendered wholly or in part unable to perform its obligations under this Agreement because of an event of Force Majeure, both Parties shall be excused from whatever performance is affected by the event of Force Majeure, provided that:

(1) The non-performing Party shall, as soon as is reasonably possible after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence.

(2) The suspension of performance shall be of no greater scope and of no longer duration than is required by the event of Force Majeure.

(3) No obligations of either Party which arose before the occurrence causing the suspension of performance and which could and should have been fully performed before such occurrence shall be excused as a result of such occurrence.

6.5 Default and Material Breaches.

6.5.1 Defaults. If either Party fails to perform any of the terms or conditions of this Agreement (a "Default" or an "Event of Default"), the nondefaulting Party shall cause notice in writing to be given to the defaulting Party, specifying the manner in which such default occurred. If the defaulting Party shall fail to cure such Default within the sixty (60) days after service of such notice, or if the defaulting Party reasonably demonstrates to the other Party that the Default can be cured within a commercially reasonable time but not within such sixty (60) day period and then fails to diligently pursue such cure, then, the nondefaulting Party may, at its option, terminate this Agreement and/or pursue its legal or equitable remedies.

6.5.2 Material Breaches. The notice and cure provisions in Paragraph 6.6.1 do not apply to Defaults identified in this Agreement as Material Breaches. Material Breaches must be cured as expeditiously as possible following occurrence of the breach.

7. Insurance.
During the term of this Agreement, Seller shall secure and continuously carry the following insurance coverage:

7.1 Comprehensive General Liability Insurance for both bodily injury and property damage with limits equal to $1,000,000, each occurrence, combined single limit. The deductible for such insurance shall be consistent with current Insurance Industry Utility practices for similar property.

7.2 The above insurance coverage shall be placed with an insurance company with an A.M. Best Company rating of A- or better and shall include:

(a) An endorsement naming Idaho Power as an additional insured and loss payee as applicable; and

(b) A provision stating that such policy shall not be canceled or the limits of liability reduced without sixty (60) days' prior written notice to Idaho Power.

7.3 Seller to Provide Certificate of Insurance. As required in Paragraph 7 herein and annually thereafter, Seller shall furnish the Company a certificate of insurance, together with the endorsements required therein, evidencing the coverage as set forth above.

7.4 Seller to Notify Idaho Power of Loss of Coverage - If the insurance coverage required by Paragraph 7.1 shall lapse for any reason, Seller will immediately notify Idaho Power in writing. The notice will advise Idaho Power of the specific reason for the lapse and the steps Seller is taking to reinstate the coverage. Failure to provide this notice and to expeditiously reinstate or replace the coverage will constitute grounds for a temporary disconnection under Section 5.3 and will be a Material Breach.

8. Miscellaneous.

8.1 Governing Law. The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of Idaho without regard to its conflicts of law principles.

8.2 Salvage. No later than sixty (60) days after the termination or expiration of this Agreement, Idaho Power will prepare and forward to Seller an estimate of the remaining value *of those Idaho Power furnished Interconnection Facilities as required under Schedule 72 and/or described in this Agreement, less the cost of removal and transfer to Idaho Power's nearest warehouse, if the Interconnection Facilities will be removed. If Seller elects not to obtain ownership of the Interconnection Facilities but instead wishes that Idaho Power reimburse the Seller for said Facilities the Seller may invoice Idaho Power for the net salvage value as estimated by Idaho Power and Idaho Power shall pay such amount to Seller within thirty (30) days after receipt of the invoice. Seller shall have the right to offset the invoice amount against any present or future payments due Idaho Power.*

9. Notices.

9.1 General. Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national currier service, or sent by first class mail, postage prepaid, to the person specified below:

If to the Seller:

Seller: ____
Attention: ____
Address: ____
City:______________________State:_________Zip: ____________
Phone:___________________Fax: __________________

If to the Company:
Idaho Power Company - Delivery
Attention: Operations Manager
1221 W. Idaho Street
Boise: Idaho 83702
Phone: 208-388-5669 Fax: 208-388-5504

9.2 Billing and Payment. Billings and payments shall be sent to the addresses set out below:

Seller: ____
Attention: ____
Address: ____
City:______________________State:_________Zip: ____________
Phone:___________________Fax: __________________

Idaho Power Company - Delivery
Attention: Corporate Cashier
PO Box 447
Salt Lake City Utah 84110-0447
Phone: 208-388-5697 email: asloan@idahopower.com

9.3 Designated Operating Representative. The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Seller's Operating Representative:

Seller: ______________________________
Attention: ______________________________
Address: ______________________________
City:____________State:________Zip: __________
Phone:____________Fax: __________

Company's Operating Representative:
Idaho Power Company - Delivery
Attention: Regional Outage Coordinator - Regional Dispatch
1221 W. Idaho Street
Boise, Idaho 83702
Over 138kV phone 208 388 2861 during regular business hours
(after hours Regional Dispatch
Eastern Region 208-388-5185
Southern Region 208-388-5190

9.5 Changes to the Notice Information. Either Party may change this information by giving five (5) Business Days written notice prior to the effective date of the change.

10. Signatures.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For the Seller

Name: ______________________________

Title:______________________________

Date: ______________

For the Company
Name: ______________________________
Title: Manager, Grid Operations – Idaho Power Company, Delivery

Date: ______________

Attachment 1

Description and Costs of the Generation Facility, Interconnection Facilities and Metering Equipment

Interconnection Details

Type of Interconnection Service:	Studied as an Idaho Power Network Resource
Full Output:	80 MW
Nominal Delivery Voltage:	345kV
Affected Parties:	NV Energy (NVE)

General Facility Description

The proposed generation projects consist of 4 (four) 20 MW wind power projects provided by 10 ea. 2.0 MW Gamesa G97 generators under four Public Utility Regulatory Policies Act (PURPA) contracts. The location of a new substation owned by the Interconnection Customer would be on private property in the SW1/4 of T14SR16E Section 29 near Idaho Power structures 15-1 and 15-2. The new substation will be the third line terminal on the existing Line #803 Midpoint to Humboldt 345 kV transmission line and will be solely utilized to interconnect the Interconnection Customer to the Idaho Power transmission system. The total project output is 80 MW.

Interconnection Point

The Interconnection Point for Wind Projects #325 and #327 will be at the customer-owned station on the transformer side of the disconnect switch labeled 301B on the single line drawing included as Attachment 2. The Point of Change of Ownership will be the same as the Interconnection Point.

Facilities Ownership

The Seller will own and maintain the substation site where Idaho Power will locate facilities.

Seller's Interconnection Facilities

The Interconnection Customer will install generators, step-up transformers, distribution collector system, step-up substation, 34.5 kV to 345 kV transformer and associated auxiliary equipment at the project location connecting the project to the Midpoint – Humboldt 345kV line. The Interconnection Customer will build, own, and maintain facilities electrically located on the Interconnection Customer's side of the Point of Change of Ownership.

The Seller will install equipment to receive signals from Idaho Power Company Grid Operations for Generator Output Limit Control ("GOLC") - see Attachment 4 Operating Requirements.

The Seller will provide phone service to IPCo's generator interconnect package as described in *Telecommunications* below.

The Seller will provide a DNP 3.0 serial data connection to the local Idaho Power Company SCADA RTU when any communication with Seller-owned and maintained equipment is required for GOLC, voltage control or other plant monitoring or control. Preliminary points lists and functional description were provided to the Seller in the Facility Study Report.

All interconnection equipment electrically located on the generator side of the Point of Change Ownership shall be owned and maintained by the Seller.

Other Facilities Provided by Seller

Telecommunications

In addition to communication circuits that may be needed by the Seller, the Seller shall provide the following communication circuits for Idaho Power's use:

1. One POTS (Plain Old Telephone Service) dial-up circuit for querying the revenue meter at the generation interconnection site.
2. One data circuit (guaranteed minimum data rate of 19,200 bits per second) for SCADA between the generation interconnection site and IPC's Boise Bench facility. The data circuit type shall be one of the following types:
   a. DDS (Digital Data Service). Please note that Frame Relay Service is not acceptable.
   b. 4-wire voice grade analog data circuit (e.g. Qwest VG36).
3. One data circuit (guaranteed minimum data rate of 19,200 bits per second) for each required Phasor Measurement Unit (PMU) between the generation interconnection site and IPC's Boise Bench facility. The data circuit type shall be one of the following types:
   a. DDS (Digital Data Service). Please note that Frame Relay Service is not acceptable.
   b. 4-wire voice grade analog data circuit (e.g. Qwest VG36).

The Seller is required to coordinate with the local communications provider to provide the communications circuits and pay the associated monthly charges. The communication circuits will need to be installed and operational prior to generating into Idaho Power system. Note that installation by the local communications provider may take several months and should be ordered in advance to avoid delaying the project. If the communication circuit types listed above are not available at the site by the local communications provider, the Seller shall confer with Idaho Power.

If high voltage protection is required by the local communications provider for the incoming cable, the high voltage protection assembly shall be engineered and supplied by the Seller. Options are available for indoor or outdoor mounting. The high voltage protection assembly shall be located in a manner that provides Idaho Power 24-hour access to the assembly for communications trouble-shooting of Idaho Power-owned equipment.

Ground Fault Equipment
The Seller will install transformer configurations that will limit the contribution of ground fault current to 20 amps or less at the Interconnection Point.

Property, Site Work and Station Building
The Seller will secure property for the substation and provide access, land clearing, grading, grounding, and fencing for the entire yard (including the Idaho Power side). A building within the substation will be provided by the Seller and a separate, lockable room will be allocated inside the building for Idaho Power and NV Energy facilities.

Easements
The Seller will secure appropriate easements with the land owner for the interconnection facilities as described in the Facility Study Report. IPCO construction will not proceed until the appropriate easements are secured.

Local Service
The Seller is responsible for local service to the control building for use by both the Seller and Idaho Power Company.

Idaho Power Company's Interconnection Facilities

Idaho Power will install a short 345 kV transmission tap between the existing Line #803 Midpoint to Humboldt 345 kV transmission line and the Interconnection Customer's owned substation. The tap is assumed to be approximately 600 feet long or less. A dead-end structure, 345 kV circuit breaker, two air-break switches, and associated relaying, control, communication and metering equipment in the substation yard and building up to the Point of Change of Ownership will be installed. See the attached single line drawing.

Idaho Power will install a 34.5kV metering package for each of the four wind parks. They will be overhead or underground equipment as specified by the customer. The primary total metering will be done at 345kV at the substation. See single line drawing as Attachment 2.

Idaho Power will maintain its own equipment physically located within the Seller's substation yard.

All interconnection equipment electrically located on the utility side of the Interconnection Point shall be owned, operated, and maintained by Idaho Power.

Estimated Cost & Ownership

The following good faith estimates are provided in 2011 dollars

Description	Ownership	Cost Estimate
Generation Facilities:		
Provided by Seller	Seller	$N/A
Interconnection Facilities:		
Inter connection Station	IPCO	$2,074,000
345kV Transmission Line Tap	IPCO	$185,000
Jack Ranch Metering (1-3)	IPCO	$54,000
Salmon Creek Metering	IPCo	$18,000
(See ATTACHMENT 6 for Project Grand Total) ***TOTAL***		**$2,331,000**

Full payment is required up front in accordance with Section 9, unless payment arrangements are made in advance with Idaho Power Operations Finance.

Billing for construction activities will be based upon actual expenditures.

Attachment 2

One-line Diagram Depicting the Small Generation Facility, Interconnection Facilities, Metering Equipment and Upgrades

Attachment 3

Milestones:

Date	Milestones
	Construction funding received by IPCO
18 months after Construction funding is received by IPCO	***IPCO Construction Complete***
1 month after IPCO Construction is Complete	***IPCO Commissioning Complete***
[to be provided by Seller]	***Commercial Operation***

These milestone dates assume that material can be procured and that outages to the existing transmission line are available to be scheduled.

Additionally, any permitting issues outside the immediate control of Idaho Power could also influence the Commercial Operation Date. Idaho Power will continue to work with the Interconnection Customers to take advantage of scheduling efficiencies.

Agreed to by:

For the Interconnection Customer ______________________________Date______________

For the Transmission Provider
Idaho Power Company, Delivery ______________________________Date______________

Attachment 4

Additional Operating Requirements for the Company's Transmission System and Affected Systems Needed to Support the Seller's Needs

The Company shall also provide requirements that must be met by the Seller prior to initiating parallel operation with the Company's Transmission System.

Operating Requirements

The project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-1992 *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems* or any subsequent standards as they may be updated from time to time.

Seller will be able to modify power plant facilities on the generator side of the Interconnection Point with no impact upon the operation of the transmission system whenever the generation facilities are electrically isolated from the transmission system via the 301B switch and a terminal clearance is issued by Idaho Power Company's Grid Operator.

Generator Output Limit Control ("Re-dispatch" or "GOLC")

The Project will be subject to reductions directed by Idaho Power Company Grid Operations during transmission system contingencies and other reliability events. When these conditions occur, the Project will be subject to Generator Output Limit Control ("GOLC") and will have equipment capable of receiving signals from Idaho Power for GOLC. Generator Output Limit Control will be a setpoint from Idaho Power to the Project indicating maximum output allowed during transmission contingencies as specified in the Facility Study Report.

Low Voltage Ride Through

The Project must be capable of riding through faults on adjacent section of the power system without tripping due to low voltage. It has been determined, through study, that the Project must be capable of remaining interconnected for any single phase voltage as low as .125 PU for 9 cycles, and for all three phase voltages as low as .11 PU for 3.7 cycles.

Commercial Operation Requirements

The Seller will be granted a requested Commercial Operation date only when all requirements have been met under this GIA and Idaho Power Company's Power Sales Agreement and NERC (North American Electric Reliability Corporation) registry requirements (see below).

NERC Registry Requirements

The Seller must be registered with NERC as a Generator Owner (GO) and/or Generator Operator (GOP) entity. See NERC registry criteria Section III(c):
http://www.nerc.com/files/Statement_Compliance_Registry_Criteria-V5-0.pdf

For further information refer to: NERC Rules of Procedure Section 500 – Organization Registration and Certification; Part 1.3. as they may be updated from time to time:
http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20101001.pdf

Meteorlogical Data

Historical wind data – Within 60 days after execution of this Agreement, the Seller shall provide Idaho Power with the following:

a) historical wind data in an electronic format from the proposed Facility site or for a location within two miles of the Facility site.
b) a third party wind assessment study report used by Seller to value investment in the Facility.

No later than 30 days prior to the Commercial Operation Date, the Seller shall have either:

a) Erected at the site at least one (1) high quality, approximate hub-height (plus or minus 20 meters), permanent, meteorological wind measurement tower(s) at location(s) on the site equipped with:

   (i) Two (2) anemometers per tower;
   (ii) Two (2) air temperature sensors per tower;
   (iii) One (1) barometric pressure sensor (with DCP sensor); and
   (iv) Two (2) wind vanes per tower, or

b) Arranged to provide Idaho Power approximate hub-height wind speed, wind direction, air temperature, barometric pressure, and data from a meteorological wind measurement tower within two miles of the Facility site.

Facility availability status shall be provided as described in the Final Facility Study no later than with the calendar month following the month of the Commercial Operation Date. Failure by the Seller to operate and maintain this equipment to provide such meteorological and turbine availability data in a manner to provide reasonably accurate and dependable data for the full term of this Agreement shall be an event of Default under paragraph 6.5.1.

Attachment 5

Reactive Power Requirements

The Project will support operation in a voltage control mode. The Project must be capable of +/- 0.95 power factor operation, as measured at the Point of Interconnection, for all MW production levels from zero MW output to full rated MW output. The Project must have equipment capable of receiving an analog setpoint, via DNP 3.0 from the Idaho Power RTU for voltage setpoint. The setpoint will be the desired voltage level as measured at the interconnect bus. The range of setpoint will be 345.00 kV to 362.25 kV as specified in the Facility Study Report.

Attachment 6

Company's Description of Special Facilities and Upgrades Required to Integrate the Generation Facility and Best Estimate of Costs

As provided in Schedule 72 this Attachment describes Upgrades, Special Facilities, including Network Upgrades, and provides an itemized best estimate of the cost of the required facilities.

Upgrades

Substation Upgrades

All changes that are made to the line must be designed and maintained in accordance with Idaho Power Company standards and the WECC standards. Existing WECC criteria require geographic diverse redundant communications paths and redundant or dual primary protection systems.

Idaho Power

- Midpoint – Protective relays will be replaced with IPCo standard SEL421/311L line relay panel. Primary breaker failure will be provided by a second SEL 421 relay.
- Midpoint - Upgrade of the L346 neutral grounding reactor for the line (currently at 32kVA and assumed at 500 kVAr)*
- Midpoint - Replace the existing Wave Trap to match the rating of the line.
- Midpoint – New 3 phase PLC.
- Jack Ranch / Salmon Creek* - A new 100 foot tall communications tower, radio and space diverse antennas would be required as well as reflector on separate site. The primary communications path shall be the establishment of a new Idaho Power owned 6 GHz microwave path from Salmon Creek / Jack Ranch transmitting to a new site such as CMMW.
- CMMW* - A new 100 foot tall communications tower, radio and space diverse antennas would be required.
  - Lower Salmon – install space diverse antennas (A structural analysis has not been accomplished on the existing tower. The tower is assumed to be structurally capable of accepting the new space diverse antennas that would be required. If the tower were found not capable of supporting the new space diverse antennas, a new 100' tower would be required. The LSMW site is an existing site on BLM land, so additional permitting is not anticipated to be required, unless the tower needs to be replaced. If a new tower were required a conditional Use Permit (CUP) would be required from Twin Falls County. Space is available to install the new radio in the existing shelter. A Digital Cross Connect System (DCS) and a larger battery bank and charger would need to be installed.)

NV Energy

- Humboldt - Relaying upgrades will also be required at the NV Energy terminal. They will consist of an SEL-421 and SEL-311L relay for primary protection. Additional relaying to perform breaker failure, back-up protective functions, and control tasks may be required by NV Energy and may not match the relaying specified by Idaho Power for the Midpoint terminal.
- Humboldt – New 3 phase PLC
- CMMW – Microwave addition to IPCo facility
- Ellen D* – New Microwave site

*NOTE: The layout of each of these new communications facilities would be similar to the typical communications site, as shown in Attachment 3 of the Facility Study Report dated 12/6/11. A minimum of 100' x 100' of permitted space would need to be provided by the wind park developer for these communications facilities.

The following good faith estimates are provided in 2011 dollars:

Description	Ownership	Cost Estimate
Substation Upgrades:		
Midpoint Substation Protection	IPCO	$200,000
Midpoint Neutral Grounding Reactor	IPCO	$126,000
Midpoint PLC/wave trap	IPCO	$473,000
Jack Ranch/Salmon Creek Communications	IPCO	$767,000
Jack Ranch/Salmon Creek PLC	IPCO	$526,000
CMMW Communications	IPCO	$1,375,000
Lower Salmon Communications	IPCO	$387,000
Humboldt Protection	NVE	$351,000
Humboldt PLC	NVE	$286,000
CMMW Communications	NVE	$125,000
Ellen D Communications	NVE	$900,000
Upgrades TOTAL		**$5,516,000**
Interconnection costs (from Attachment 1) *TOTAL*		**$2,331,000**
PROJECT GRAND TOTAL		**$7,847,000**

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 48

IDAHO POWER®
An IDACORP Company

REVISED FINAL
Generator Interconnection
Facility Study Report

for

Salmon Creek 20 MW Wind Project #325 and
Jack Ranch 60 MW Wind Project #327

for

Exergy Development Group of Idaho, LLC

in

Twin Falls County, ID

February 15, 2012

FINAL - FACILITY STUDY REPORT (FSR)

**Salmon Creek 20 MW Wind Project #325 and
Jack Ranch 60 MW Wind Project #327**

February 15, 2012

1.0 General Facility Description

The proposed generation projects consist of 4 (four) 20 MW wind power projects provided by 10 ea. 2.0 MW Gamesa G97 generators under four Public Utility Regulatory Policies Act (PURPA) contracts. The location of a new substation owned by the Interconnection Customer would be on private property in the SW1/4 of T14SR16E Section 29 near structures 15-1 and 15-2. Idaho Power will build and own the new substation and control building that will share Idaho Power and NV Energy relay and communications equipment. The new substation will be the third line terminal on the existing Line #803 Midpoint to Humboldt 345 kV transmission line and will be solely utilized to interconnect the Interconnection Customer to the Idaho Power transmission system.

Interconnection Customer:
Dustin Shively
Exergy Development Group of Idaho, LLC
802 W. Bannock, Suite 1200
Boise, Idaho 83702
dshively@exergydevelopment.com

Standard Generator Interconnection Agreements under Idaho Power Company's Open Access Transmission Tariff (OATT) or Schedule 72 between Interconnection Customers and Idaho Power Company – Delivery (Transmission Owner) for the Salmon Creek 20 MW Wind Project #325 and Jack Ranch 60 MW Wind Project #327, will be prepared for these projects.

A System Impact Re-Study has been completed for the modifications requested for Jack Ranch 60 MW Wind Project #327; this report does not require any additional upgrades.

1.1 Interconnection Point

The Interconnection Point for Wind Projects #325 and #327 will be at Idaho Power Company's substation on the transformer side of the disconnect switch labeled 301B on the single line drawing attached.

1.2 Point of Change of Ownership

The Point of Change of Ownership for Salmon Creek 20 MW Wind Project #325 and Jack Ranch 60 MW Wind Project #327 is electrically the same as the Interconnection Point.

1.3 Customer's Interconnection Facilities

The Interconnection Customer will install generators, step-up transformers, distribution collector system, step-up substation, 34.5 kV to 345 kV transformer and associated auxiliary equipment at the project location connecting the project to the Midpoint – Humboldt 345kV line. The Interconnection Customer will build, own, and maintain facilities electrically located on the Interconnection Customer's side of the Point of Change of Ownership.

1.4 Other Facilities Provided by Interconnection Customer

1.4.1 Telecommunications

In addition to communication circuits that may be needed by the Interconnection Customer, the Interconnection Customer shall provide the following communication circuits for Idaho Power's use:

1. One POTS (Plain Old Telephone Service) dial-up circuit for querying the revenue meter at the generation interconnection site.
2. One data circuit (guaranteed minimum data rate of 19,200 bits per second) for SCADA between the generation interconnection site and IPC's Boise Bench facility. The data circuit type shall be one of the following types:
    a. DDS (Digital Data Service). Please note that Frame Relay Service is not acceptable.
    b. 4-wire voice grade analog data circuit (e.g. Qwest VG36)
3. One data circuit (guaranteed minimum data rate of 19,200 bits per second) for <u>each</u> required Phasor Measurement Unit (PMU) between the generation interconnection site and IPC's Boise Bench facility. The data circuit type shall be one of the following types:
    a. DDS (Digital Data Service). Please note that Frame Relay Service is not acceptable.
    b. 4-wire voice grade analog data circuit (e.g. Qwest VG36)

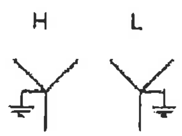
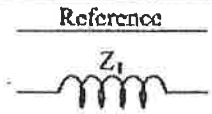
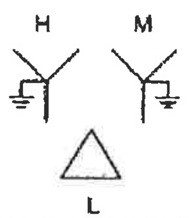
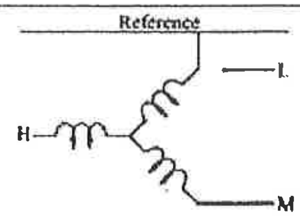
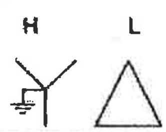
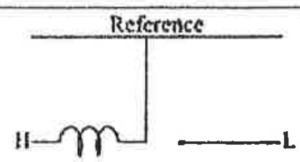
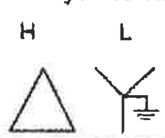
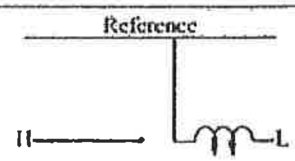
The Interconnection Customer is required to coordinate with a communications provider to provide the communications circuits and pay the associated one time setup and periodic charges. The communication circuits will need to be installed and operational prior to generating into the Idaho Power system. Note that installation by communications provider may take several months and should be ordered in advance to avoid delaying the project. If the communication circuit types listed above are not available at the site by a communications provider, the Interconnection Customer shall confer with Idaho Power.

If high voltage protection is required by the communications provider for the incoming communications provider cable, the high voltage protection assembly shall be engineered and supplied by the Interconnect Customer. Options are available for indoor or outdoor mounting. The high voltage protection assembly shall be located in a manner that provides Idaho Power 24-hour access to the assembly for trouble-shooting of Idaho Power owned equipment.

1.4.2 Ground Fault Equipment

The permissible winding configuration of the interconnect transformer is dependent on the application but shall provide a source of ground current for transmission relaying and the transmission system.

Table 1
Transformer configurations

Transformer Type	Zero-Sequence Connection	Comments
Wye-Grounded Wye-Grounded 		Not a ground source but passes ground current. Independent power producer must supply enough ground current for IPC transmission relaying.
Wye-Grounded Wye-Grounded with Delta Tertiary 		Ground source for transmission relaying.
Wye-Grounded Delta 		Ground source available to transmission relaying. Independent power producer is Delta connected—no ground source.
Delta Wye-Grounded 		No ground source available to transmission relaying. High-side grounding bank required to provide ground current.

1.4.3 Easements/ Ownership

The Interconnection Customer will provide to Idaho Power a surveyed (Metes & Bounds) legal description along with exhibit map for Idaho Power's facilities. After the legal description has been delivered to IPCO for review, the Interconnection Customer will supply Idaho Power an executed deed conveying satisfactory fee title to IPCO for the land site for the substation and communication facilities.

1.4.4 Generator Output Limit Control

The Interconnection Customer will install equipment to receive signals from Idaho Power Grid Operations for Generation Output Limit Control ("GOLC") - see Section 3.0 Operating Requirements.

1.4.5 Local Service

The Interconnection Customer is responsible to arrange for local service to the control building for use by the both the Interconnection Customer and Idaho Power.

1.4.6 Property, Site Work, and Substation Building

The Interconnection Customer will secure and transfer ownership of the property to IPCO for the substation and communication facilities to be built by Idaho Power Company, as referenced in Section 1.4.3. A building within the substation will have a separate, lockable room allocated for NV Energy facilities. The substation and communication facilities will be owned and maintained by Idaho Power.

1.4.7 Meteorological Data

In order to integrate the wind energy into the Idaho Power system, the Interconnection Customer will provide weather data to IPCO from the proposed Facility Site or from a location within two miles of the Facility site consisting of the following instantaneous weather parameters that will be collected via each meteorological observation tower at 10m & 80m above ground: Wind Speed(m/s), Wind Direction, Air Temperature (degrees Cent), along with Relative Humidity, and Barometric Pressure. This data shall be provided to IPCo hourly via commonly accepted electronic web service standards or similar communication method. The Customer will provide relevant historical meteorological data to IPC. Additionally, the Customer shall submit to Idaho Power the physical and technical specifications for all meteorological measurement devices, geographic locations and technical specifications of all turbines. The associated cost for obtaining this data is the Customers responsibility and therefore not included in the Facility Study estimate.

1.5 Idaho Power Company's Interconnection Facilities

Idaho Power will install a short 345 kV transmission tap between the existing Line #803 Midpoint to Humboldt 345 kV transmission line and the Interconnection Customer's owned substation. The tap is assumed to be approximately 600 feet long or less. A dead-end structure, 345 kV circuit breaker, two air-break switches, and associated relaying, control, communication and metering equipment in the substation yard and building up to the Point of Change of Ownership will be installed. See the attached single line drawing.

Idaho Power will install a 34.5kV metering package for each of the four wind parks. They will be overhead or underground equipment as specified by the customer. The primary total metering will be done at 345kV at the substation.

1.6 *Facility Estimated Cost*

The following good faith estimates are provided in 2011 dollars:

Description	Ownership	Cost Estimate
Interconnection Facilities:		
Interconnection Station	IPC	$2,074,000
345 kV Transmission Line Tap	IPC	$185,000
Jack Ranch Metering (1-3)	IPC	$54,000
Salmon Creek Metering	IPC	$18,000
SUBTOTAL		**$2,331,000**
See Section 6 for Project Grand Total		

2.0 Milestones

Date	Milestone
TBD	*Construction Funds Received by IPCO*
18 Months after Construction Funds Received by IPCO	*IPCO Construction Complete*
1 month after IPCO Construction Complete	*IPCO Commissioning Complete*
TBD by seller	*Commercial Operation Date*

These milestone dates assume that material can be procured and that outages to the existing transmission line are available to be scheduled. Additionally, any permitting issues outside the immediate control of Idaho Power could also influence the Commercial Operation Date. Idaho Power will continue to work with the Interconnection Customers to take advantage of scheduling efficiencies.

3.0 Operating Requirements

The project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-1992 *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems* or any subsequent standards as they may be updated from time to time.

The Salmon Creek and Jack Ranch Wind Projects will be subject to reductions directed by Idaho Power Grid Operations during transmission system contingencies. When outages occur, the Project will be subject to Generator Output Limit Control ("GOLC") and will have equipment capable of receiving an analog setpoint via DNP 3.0 from Idaho Power for GOLC. Generator Output Limit Control will be a setpoint from Idaho Power to the Project indicating maximum output allowed during transmission contingencies. For detailed information refer to Attachment 4.

Low Voltage Ride Through - The Project must be capable of riding through faults on adjacent section of the power system without tripping due to low voltage. It has been determined, through study, that the Project must be capable of remaining interconnected for any single phase voltage as low as .125 PU for 9 cycles, and for all three phase voltages as low as .11 PU for 3.7 cycles.

Interconnection Customers will be able to modify facilities on the Interconnection Customers' side of the Interconnection Point with no impact upon the operation of the transmission or distribution system whenever the generation facilities are electrically isolated from the system via the 301B airbreak disconnect switch or other approved methods by Idaho Power system operations.

4.0 Reactive Power

The Project must be capable of +/- 0.95 power factor operation, as measured at the Interconnection Point, for all MW production levels from zero MW output to full rated MW output. The Project must have equipment capable of receiving an analog setpoint, via DNP 3.0 from Idaho Power for voltage setpoint. The setpoint will be the desired voltage level as measured at the interconnect bus. The range of setpoint will be 345.00 kV to 362.25 kV.

5.0 Upgrades Required

5.1 Substation Upgrades

All changes that are made to the line must be designed and maintained in accordance with Idaho Power standards and the WECC standards. Existing WECC criteria require geographic diverse redundant communications paths and redundant or dual primary protection systems.

Idaho Power

- Midpoint – Protective relays will be replaced with IPCo standard SEL421/311L line relay panel. Primary breaker failure will be provided by a second SEL 421 relay.
- Midpoint - Upgrade of the L346 neutral grounding reactor for the line (currently at 32kVA and assumed at 500 kVAr)*
- Midpoint - Replace the existing Wave Trap to match the rating of the line.
- Midpoint – New 3 phase PLC.
- Jack Ranch / Salmon Creek* - A new 100 foot tall communications tower, radio and space diverse antennas would be required as well as reflector on separate site. The primary communications path shall be the establishment of a new Idaho Power owned 6 GHz microwave path from Salmon Creek / Jack Ranch transmitting to a new site such as CMMW.
- CMMW* - A new 100 foot tall communications tower, radio and space diverse antennas would be required.
    - Lower Salmon – install space diverse antennas (A structural analysis has not been accomplished on the existing tower. The tower is assumed to be structurally capable of accepting the new space diverse antennas that would be required. If the tower were found not capable of supporting the new space diverse antennas, a new 100' tower would be required. The LSMW site is an existing site on BLM land, so additional permitting is not anticipated to be

required, unless the tower needs to be replaced. If a new tower were required a conditional Use Permit (CUP) would be required from Twin Falls County. Space is available to install the new radio in the existing shelter. A Digital Cross Connect System (DCS) and a larger battery bank and charger would need to be installed.)

NV Energy

- Humboldt - Relaying upgrades will also be required at the NV Energy terminal. They will consist of an SEL-421 and SEL-311L relay for primary protection. Additional relaying to perform breaker failure, back-up protective functions, and control tasks may be required by NV Energy and may not match the relaying specified by Idaho Power for the Midpoint terminal.
- Humboldt – New 3 phase PLC
- CMMW – Microwave addition to IPCo facility
- Ellen D* – New Microwave site

*NOTE: The layout of each of these new communications facilities would be similar to the typical communications site, as shown in Attachment 3. A minimum of 100' x 100' of permitted space would need to be provided by the wind park developer for these communications facilities.

Estimated Costs

The following good faith estimates are provided in 2011 dollars:

Description	Ownership	Cost Estimate
Interconnection Facilities (from section 1.6):		
Interconnection Station	IPC	$2,074,000
345 kV Transmission Line Tap	IPC	$185,000
Jack Ranch Metering	IPC	$54,000
Salmon Creek Metering	IPC	$18,000
SUBTOTAL		**$2,331,000**
Substation Upgrades:		
Midpoint Protection	IPC	$200,000
Midpoint Neutral Grounding Reactor	IPC	$126,000
Midpoint PLC/ wave trap	IPC	$473,000
Jack Ranch / Salmon Creek Communications	IPC	$767,000
Jack Ranch / Salmon Creek PLC	IPC	$526,000
CMMW Communications	IPC	$1,375,000
Lower Salmon Communications	IPC	$387,000
Humboldt Protection	NVE	$351,000
Humboldt PLC	NVE	$286,000
CMMW Communications	NVE	$125,000
Ellen D Communications	NVE	$900,000
SUB TOTAL		$5,516,000
GRAND TOTAL		$7,847,000

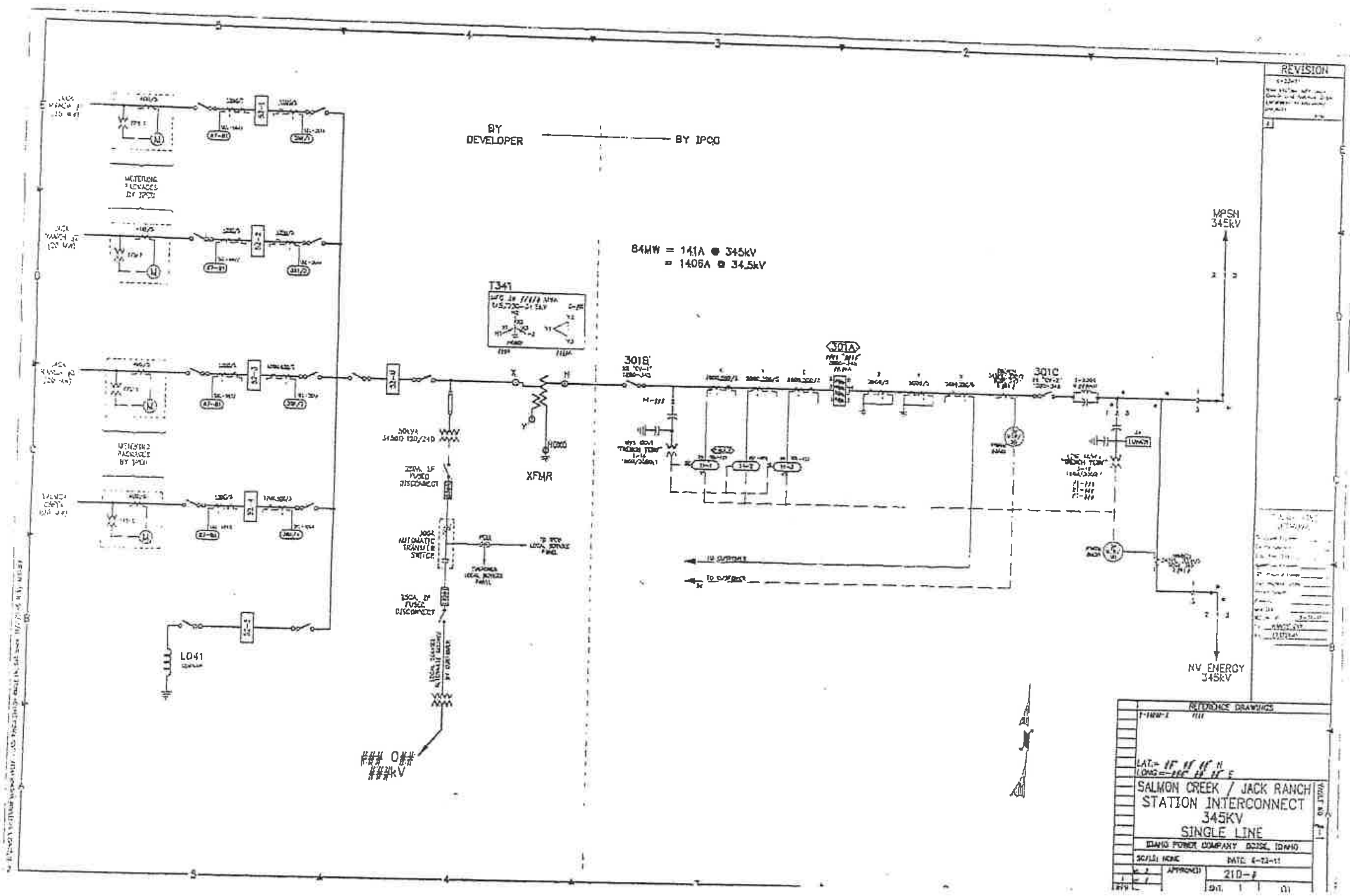
Note Regarding Transmission Service:

This Facility Study is a Network Resource Interconnection Facility Study. This study identifies the facilities necessary to integrate the Generating Facility into Idaho Power's network to serve load within Idaho Power's balancing area. Network Resource Interconnection Service in and of itself does not convey any right to deliver electricity to any specific customer or Point of Delivery.

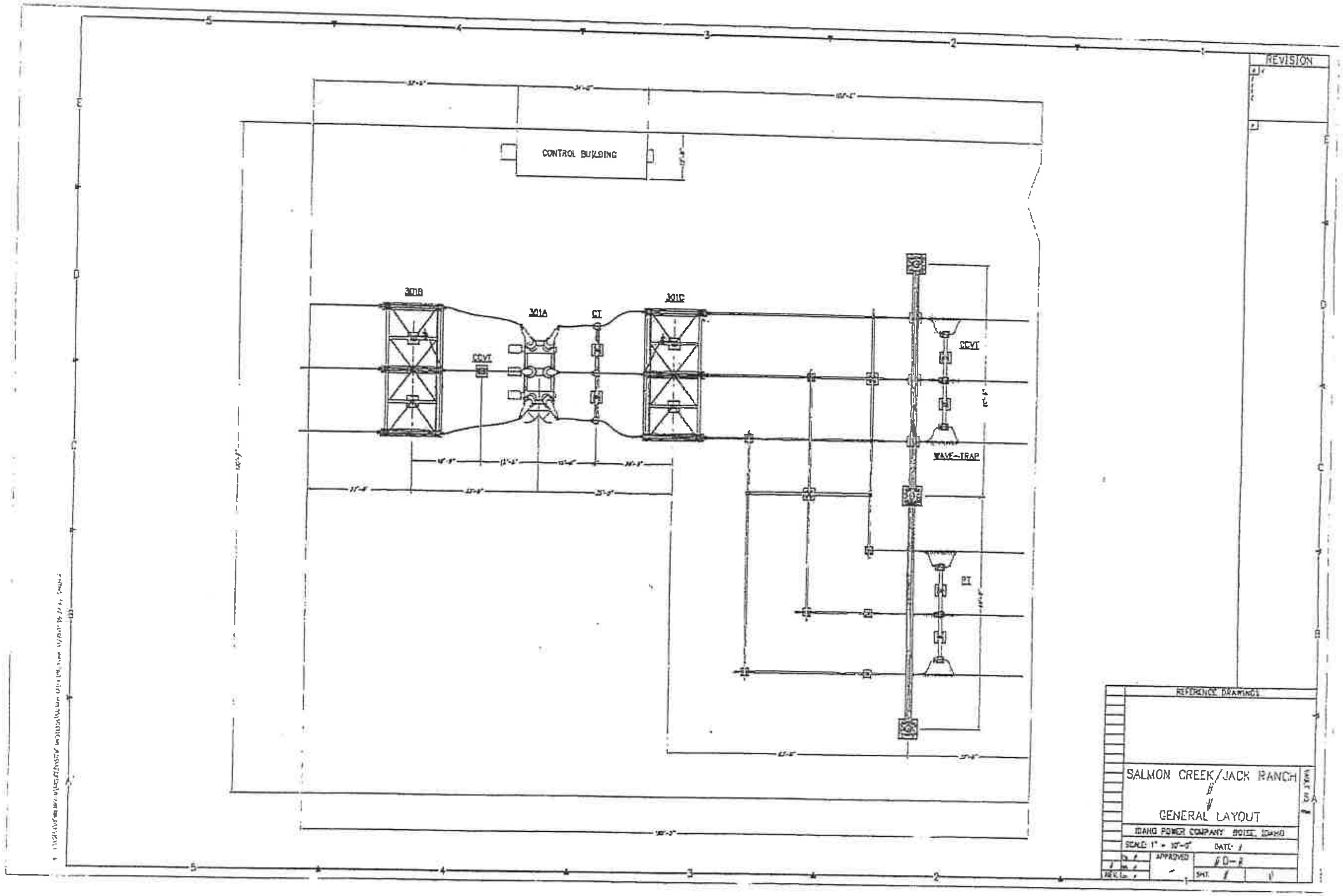
ATTACHMENTS

Attachment 1: Salmon Creek/ Jack Ranch Single Line
Attachment 2: Salmon Creek/ Jack Ranch General Location
Attachment 3: Typical Communications Site, General Arrangement
Attachment 4: Generation Interconnection Control & Data Point Requirements

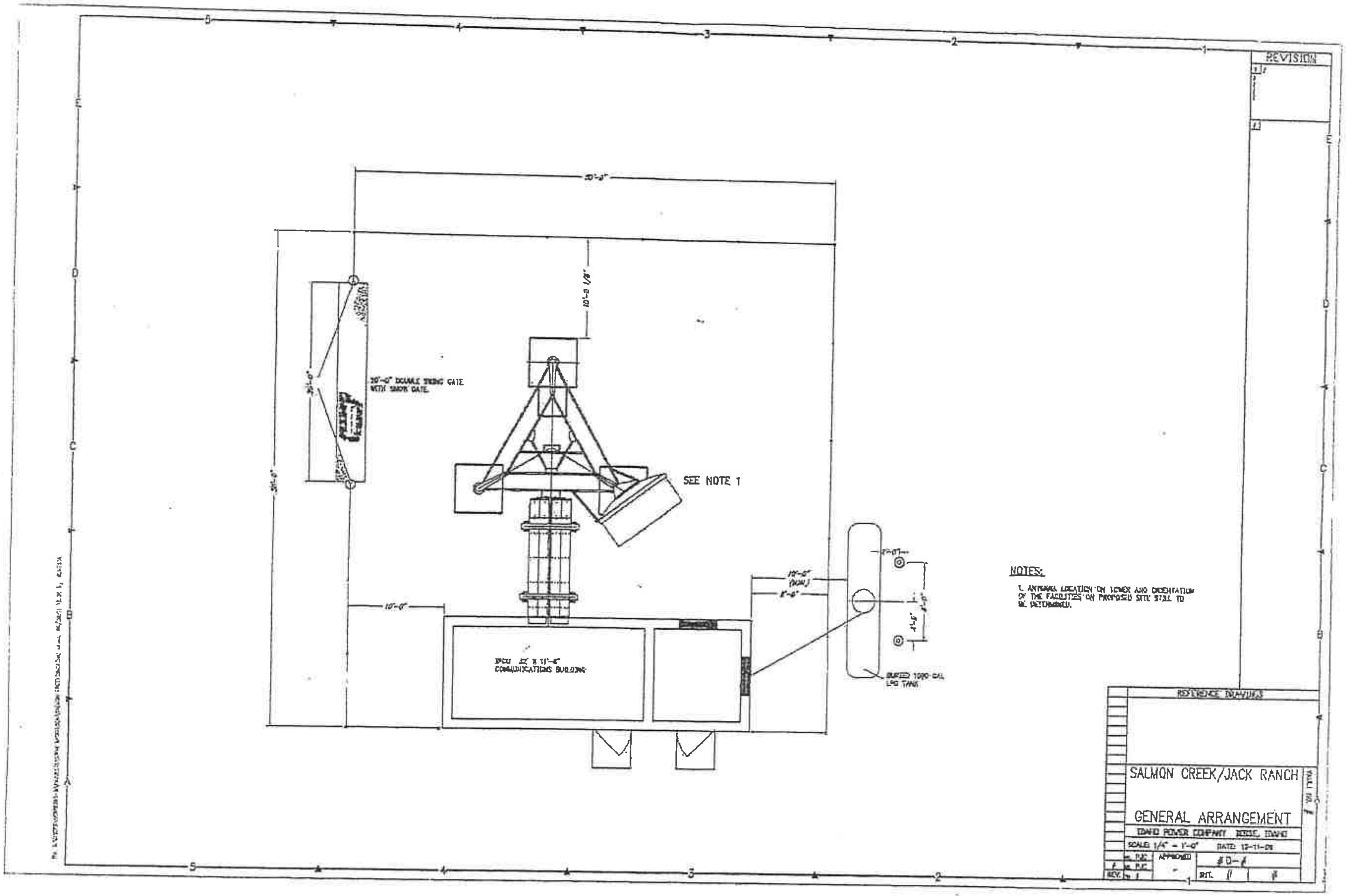
Attachment 1



Attachment 2



Attachment 3



Attachment 4

Generation Interconnection Control Requirements

Generator Output Limit Control (GOLC)

- IPC requires Interconnected Power Producers to accept GOLC signals from our EMS.
- The GOLC signals will consist of two points shared between the IPC EMS and the Customer's Generator Controller:
  1. GOLC Setpoint: An analog output that contains the MW value the Customer should curtail to, should a GOLC request be made via the GOLC On/Off discrete output Control point.
     - An Analog Input feedback point must be updated (to reflect the GOLC setpoint value) by the Customer Controller upon the Controller's receipt of the GOLC setpoint change, with no intentional delay.
  2. GOLC On/Off: A discrete output (DO) control point with latching Off/On states. Following a "GOLC On" control, the Customer Controller will run power output back to the MW value specified in the GOLC Setpoint. Following a "GOLC Off" control, the Customer is free to run to maximum possible output.
     - A Discrete Input feedback point must be updated (to reflect the GOLC DO state) by the Customer Controller upon the Controller's receipt of the GOLC DO state change, with no intentional delay.
- If a GOLC control is issued, it is expected to see MW reductions start within 1 minute and plant output to be below the GOLC Setpoint value within 10 minutes.

Voltage Control

- IPC requires Interconnected Power Producers to accept Voltage Control signals from our EMS when they are connected to our transmission system.
- The voltage control will consist of one setpoint shared between the IPC EMS and the Customer Controller.
- The setpoint will contain the desired target voltage for the plant to operate at.
- The control will always be active, there is no digital supervisory point like the Curtail On/Off control above.
  - When a setpoint change is issued an Analog Input feedback point must be updated (to reflect the Voltage Control setpoint value) by the Customer Controller upon the Controller's receipt of the Voltage Control setpoint change, with no intentional delay.
  - When a setpoint change is received by the Customer Controller, the Voltage Control system should react with no intentional delay.
  - The voltage control system should operate in a dead band of +/-5% of the control setting range.
- The wind parks should supervise this control by setting up "reasonability limits", i.e. configure a reasonable range of values for this control to be valid. As an example, they will accept anything between .95 and 1.05 for the set point. In the case they are fed an erroneous value outside this range, their control system defaults to the last known, good value.

Generation Interconnection Data Points Requirements

Digital Inputs (DNP Obj. 01, Var. 2)			
Index	Description	State (0/1)	Comments:
0	52A Customer Total Breaker	Open/Closed	Sourced at substation
1	GOLC Off/On Control Received (Feedback)	Off/On	Provided by Customer

Digital Outputs (DNP Obj. 10, Var. 1)		
Index	Description	Comments:
0	GOLC Off/On	Provided by IPCO
	NOTE: GOLC Setpoint indicates MW value to curtail to when GOLC Off/On DO is ON.	

Analog Inputs (DNP Obj. 30, Var. 2)							
Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
0	GOLC Setpoint Value Received (Feedback)	32767	-32768	TBD	TBD	MW	Provided by Customer
1	Voltage Control Setpoint Value Rec'd (Feedback)	32767	-32768	TBD	TBD	kV	Provided by Customer

2	Maximum Park Generating Capacity*	32767	-32768	TBD	TBD	MW	Provided by Customer
3	Number of Turbines In High Speed Cutout*	32767	-32768	32767	-32768	Units	Provided by Customer
4	Ambient Temperature*	32767	-32768	327.67	-327.68	F or C	Provided by Customer
5	Wind Direction*	32767	-32768	3276.7	-3276.8	Deg	Provided by Customer
6	Wind Speed*	32767	-32768	327.67	-327.68	MPH or m/s	Provided by Customer

Analog Outputs (DNP Obj. 40, Var. 2)							
Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
0	GOLC Setpoint	32767	-32768	TBD	TBD	MW	Provided by IPCO
1	Voltage Control Setpoint	32767	-32768	TBD	TBD	kV	Provided by IPCO
	NOTE: Curtailment Setpoint indicates MW value to Curtail to when Curtailment Off/On DO is ON.						

* - Data required from Wind Customers

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 49

IDAHO POWER®
An IDACORP Company

April 10, 2012

VIA E-MAIL & U.S. CERTIFIED MAIL

James Carkulis
Exergy Development Group
802 W. Bannock, 12th Floor
Boise, ID 83702

Re: Jack Ranch Project – April 4, 2012, Meeting

Dear Mr. Carkulis:

This letter follows-up and summarizes the meeting between representatives of Exergy and Idaho Power held on April 4, 2012, at Idaho Power's offices related to Exergy's Jack Ranch Project. As Idaho Power reiterated to you when we met, the interconnection facilities and necessary system upgrades for the Jack Ranch Project will not be complete until at least 18-months after receipt of a signed Generator Interconnection Agreement ("GIA") and the requisite construction funding. As there is currently no signed GIA, nor have we received any construction funding from Exergy for this project, it will not be possible to have your interconnection constructed and energized before the end of 2012.

Idaho Power understands that Exergy is looking at all available options to allow its project to come online prior to the end of 2012. As we discussed at our meeting on April 4, 2012, while Idaho Power will work with you to expedite the construction of your interconnection facilities, Idaho Power will not commit to an online date of year-end 2012 as it is not possible to have such interconnection facilities constructed and energized by the end of the year. Idaho Power has consistently advised you that design, permitting, and procurement and construction-lead times on interconnection facilities are estimated at a minimum of 18-months from the date on which Idaho Power receives construction funding. These lead-times are necessary to conduct the necessary scoping, engineering, design, construction, installation, and testing of interconnection facilities.

As we have also discussed with you, construction of the interconnection facilities for the Jack Ranch Project is unique, and further complicated, in that it involves system upgrades for facilities owned by NV Energy. Idaho Power has no control over these facilities and is dependent upon NV Energy for required upgrades to its effected facilities. As we communicated to you, NV Energy has advised Idaho Power that it is not doing any construction in 2012 on the facilities necessary for the Jack Ranch Project to come online. You requested at the April 4 meeting to speak directly with NV Energy yourself, to which Idaho Power indicated it has no objection. Additionally, some of the interconnection facilities for the Jack Ranch Project could require permits from the United States Bureau of Land Management ("BLM") that would present an additional complication. As we have previously discussed on several occasions, including the meeting on April 4, the BLM permitting process in and of itself can take upwards of 24-months to complete. Since we have not received any construction funding from you, nor have you signed a GIA, we have yet to begin the arduous, and potentially time consuming BLM permitting process. Taken together, these items are clear indicators that interconnection facilities for the Jack Ranch Project will not be energized until after 2012.

You made statements at our April 4 meeting to the effect that with your Company's help, and the possible assistance of third-party contractors, that Idaho Power's engineering, design, procurement, and construction activities required to complete the interconnection of your project could be escalated to meet a 2012, year-end energization. While your optimism is admirable, it is unfortunately not realistic to expect completion of the interconnection, nor energization of your project by year-end 2012. As stated, Idaho Power will use commercially reasonable efforts, and work with you to expedite the construction of your interconnection facilities, including the use of third-party contractors – and including additional costs – if authorized and borne entirely by Exergy – to expedite the work required to interconnect your project to Idaho Power's system, allowing its energization. However, so as to be clear, I must reiterate that this does not change Idaho Power's estimate of a minimum of 18 months from payment of funds and execution of the GIA to complete the necessary system upgrades and interconnection facilities required to energize your project on Idaho Power's system, and even given the other uncertainties involved, it could take longer than 18 months still.

Given that the interconnection facilities for your project will not be constructed prior to the end of 2012, please advise whether you wish to continue to proceed with interconnection for the Jack Ranch Project. To that end, enclosed please find a copy of the Revised Facility Study Report (FSR) dated February 15, 2012, and a draft GIA for the Jack Ranch Project. The GIA is part of Idaho Power Company's Rate Schedule 72 tariff approved by the Idaho Public Utilities Commission (IPUC). The IPUC has the authority to review and modify these schedules periodically. You may view the most current tariff at Idaho Power's website: http://www.idahopower.com/aboutus/regulatoryinfo/tariffs.asp The attachments to the GIA are based on the Facility Study Report. Please review the attachment to make sure they are comprehensive and accurate and advise me of any changes as soon as possible.

Although the preferred method of funding is full payment upfront; payment arrangements may be requested. If you have not already done so, please contact Aubrac Sloan (208-388-5697), Operations Finance, at your earliest convenience to discuss Idaho Power's credit requirements for construction funding. Once we receive funding, or the credit requirement is met, we can proceed with design and construction of the project pursuant to the executed GIA. The actual construction and labor charges will be reconciled approximately 90 days subsequent to project completion.

Under the Generator Interconnection process, the following items must be provided to me on or before execution of the GIA:

1. Your requested in service date to complete Attachment 3 of the GIA;
2. Proof of Site Control for the project;
3. Insurance certification pursuant to Section 7 of the GIA (certificate, 1 endorsement for Additional insured, and 1 for the cancellation notice);
4. Financial arrangements approved by Idaho Power credit department, or full payment for construction;

Failure to submit all of the requested items above by **May 11, 2012,** will cause your Generator Interconnection request to have been deemed withdrawn and terminated. Please contact me at your earliest convenience with any questions.

Sincerely,

Rich Bauer

Rich Bauer
Operations Manager

CC: Donovan Walker, Lead Counsel
Jason Williams, Corporate Counsel
Tessia Park
Aubrae Sloan
Nancy Cyr

Encl: Final Facility Study Report
draft GIA for Jack Ranch Project # 325/327

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 50

exergy

09 May 2012

Rich Bauer
Operations Manager
Idaho Power Company
1221 W. Idaho Street
Boise, ID 83702

RE: Jack Ranch GIA #325 & $327

Rich:

Per your letter of 10 April 2012, please find the following items for review.

1. In-service date of 15 December 2012
2. Copies of site control [enclosed]
3. Proof of insurance [enclosed]
4. We have commenced the financial arrangements conversation with Aubrae on the $7,847,000, but we cannot financially commit until we have an executable copy of the GIA in hand and provided the extension on the 4 Jack Ranch PPAs to 31-December-2013. None of our financing agents would grant such a commitment without the executed documents in hand.
5. As with the Thousand Springs interconnection for Idaho Wind Partners, which was considered both a SGIA and LGIA, we would like a provision embedded into the Idaho Power LGIA also in this GIA draft allowing for self-build. It is hard to attempt to bifurcate this interconnect solely to an SGIA if we must meet NERC and FERC compliance.

Thank you.

Regards,

James T. Carkulis

Exergy Development Group 802 W Bannock, 12th Floor Boise, ID 83702 P 208.336.9793

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 51

IDAHO POWER®
An IDACORP Company

May 14, 2012

VIA E-MAIL & U.S. CERTIFIED MAIL

James Carkulis
Exergy Development Group
802 W. Bannock, 12th Floor
Boise, ID 83702

Re: Jack Ranch Projects GIA

Dear Mr. Carkulis:

This letter is in response to your letter dated May 9, 2012 with regard to the Jack Ranch Projects. As Idaho Power has communicated to you on multiple occasions (including most recently Idaho Power's April 10, 2012, letter to you), **it will not be possible to have the interconnection constructed and energized for the Jack Ranch Projects before the end of 2012**. While Idaho Power understands your desire to have an on-line date by the end of 2012, your desire and the reality of designing, engineering and constructing the interconnection facilities and system upgrade are starkly different. As we have told you on multiple occasions (and again most recently in the April 10, 2012, letter), the interconnection facilities and necessary system upgrades for the Jack Ranch Projects will not be complete until at least 18-months after receipt of a signed Generator Interconnection Agreement ("GIA") and the requisite construction funding. Since neither of these events has occurred, the **Jack Ranch Projects will not be on-line before the end of 2012.**

That said, Idaho Power understands that Exergy is looking at all available options to expedite the construction of interconnection facilities for the Jack Ranch Projects. As we have previously explained to you, Idaho Power will use commercially reasonable efforts, and work with you to expedite the construction of your interconnection facilities, including the use of third-party contractors – and including additional costs – if authorized and borne entirely by Exergy – to expedite the work required to interconnect your project to Idaho Power's system, allowing its energization. To that end, we have included applicable language in this regard in Attachment 3 of this Final GIA we are tendering with this letter.

However, so as to be clear, once again, Idaho Power must reiterate that this does not change Idaho Power's estimate of a minimum of 18 months from payment of funds and execution of the Final GIA to complete the necessary system upgrades and interconnection facilities required to energize your project on Idaho Power's system, and even given the other uncertainties and contingencies involved (as explained in the Final GIA), it could take longer than 18 months once a signed GIA and the required payments is received.

Enclosed please find a copy of the Final GIA for the Jack Ranch Projects. As you did not provide any edits to the draft GIA we sent on April 10, 2012, Idaho Power has finalized this document and it is now ready for your signature. Once we have a fully executed Final GIA and the financing arrangements for the $7,847,000 of required construction costs are made, Idaho

Power will commence with the design, engineering and construction of the interconnection for the Jack Ranch Projects.

As for the Firm Energy Sales Agreements ("FESAs") for the four Jack Ranch Projects, as you may recall, Idaho Power representatives, including myself, met with you and three of your attorneys to discuss the FESA's at Idaho Power's corporate headquarters on April 10, 2012. At that meeting, you told Idaho Power that you would be submitting an offer of settlement to Idaho Power. To date, we have not received any offer from you. Your May 9, 2012 letter makes a demand to Idaho Power to unilaterally extend the Schedule Operation Date for the "4 Jack Ranch PPAs to 31-December-2013." Idaho Power will not agree to this demand. The Scheduled Operation Date in the FESAs is June 30, 2012. Failure to achieve an Operation Date within 90 days of June 30, 2012 will be deemed a material breach by you of the FESAs.

Idaho Power has and will continue to pursue all commercially reasonable efforts to energize the Jack Ranch Projects pursuant to the April 10, 2012 letter, this letter and the attached, final GIA. However, your refusal to accept the reality of the timeframes we have repeatedly and consistently communicated to you for the Jack Ranch Projects is becoming a matter of serious concern for Idaho Power. Failure to submit an executed copy of the enclosed Final GIA, which includes the estimated milestones for the completion of construction, and complete the necessary financing arrangements for the Jack Ranch Projects **by June 13, 2012,** will result in Idaho Power terminating your generator interconnection request and withdrawing the Jack Ranch Project from the generator interconnection queue. You will receive no further notice if the signed GIA and payment is not received by that date.

Sincerely,

Tess Park

Tess Park
Load Serving Operations Director

CC: Donovan Walker, Lead Counsel
Jason Williams, Corporate Counsel
Aubrae Sloan, Finance
Nancy Cyr, Delivery Project Manager

Encl: GIA for Jack Ranch Projects # 325/327

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 52

01 June 2012

Lisa A. Grow
Senior Vice President, Power Supply
Idaho Power Company
PO Box 70
Boise, Idaho 83707

Re: Cottonwood Wind Park – Project #31721100, Deep Creek Wind Park – Project # 31721200, Rogerson Flats Wind Park – Project # 31721300 and Salmon Creek Wind Park – Project # 31721400

Dear Ms. Grow,

Each of Cottonwood Wind Park, LLC, Deep Creek Wind Park, LLC, Rogerson Flats Wind Park, LLC and Salmon Creek Wind Park LLC (collectively, the "Project Companies") has entered into an individual Firm Energy Sales Agreement with Idaho Power Company dated December 10, 2010 (collectively, the "Project PPAs").

I am writing this letter on behalf of the Project Companies to ask that Idaho Power Company amend Appendix B (Facility and Point of Delivery) of each of the Project PPAs such that Section B – 3 (Scheduled First Energy and Operation Date) reads as follows:

> "Seller has selected **November 1, 2012** as the Scheduled First Energy Date
> Seller has selected **December 1, 2012** as the Scheduled Operation Date"

The current schedule given by Idaho Power Transmission is December 2013.

This amendment will result in the schedule of the Project PPAs being consistent with each of the interconnection agreements applicable to each of the projects.

The parties originally agreed to June 30, 2012 as the Scheduled Operation Date because Idaho Power Company had originally provided the Project Companies with an initial on-line date of December 31, 2011 based on the interconnection studies. Specifically, the Generator Connector Feasibility Study final report dated July 28, 2010 for projects queue # 325 and queue #327 completed by Idaho Power Company is premised upon a proposed in-service date of December 2011 (See Section 4.0 of the final report). Moreover, the Generator Connector System Impact Study final report dated December 29, 2010 for projects queue #325 and queue #327 completed by Idaho Power Company is also based on the same proposed in-service date of December 2011 (See Section 4.0 of the final report).

The information we've received from Idaho Power Company in these studies has triggered many events. The project companies left sufficient room to build from the energization date of December 2011 of the substation to completion under the PPA. The project companies have been in continuous construction of these projects since December of 2011 based in large part on the information from Idaho Power Company contained in these studies. For example, the project companies have ordered substation equipment, readied the transformer to ship, built roads and excavated foundations, among other things. It was reasonable for the project companies to take these actions based on the fact that we were getting this information from Idaho Power Company. We hope that we have not relied on this information to our detriment.

Based on the results the studies delivered from Idaho Power Company, the parties included six months of contingency (should Idaho Power Company experience any delays in the construction of the necessary interconnection facilities) and, thus, the June 30, 2012 date was included in each of the Project PPAs. The Project Companies entered into the Project PPAs (with the aforementioned dates) based in large part on the information provided by Idaho Power Company. The Project Companies acted in good faith and in a commercially reasonable manner based on the information that Idaho Power Company provided.

Now that Idaho Power Company has made the Project Companies aware that the interconnection facilities will not be completed in order to allow the Project Companies to meet the Scheduled Operation Date, I am asking simply to have the dates in the Project PPAs reflect what Idaho Power Company is telling us that they will accomplish regarding the interconnection facilities.

Please note, each of the Project Companies has made, in good faith and based on the information provided by Idaho Power Company in the aforementioned studies, the applicable security deposits with the assumption that Idaho Power Company would be able to construct the interconnection facilities on the schedule originally set by the interconnection studies. The Project Companies have been diligently trying to work with Idaho Power Company to overcome this delay, but it is beyond the control of the Project Companies.

If you agree with the amendment, please respond appropriately and I will have the appropriate amendments drafted for each of the Project PPAs. I am very appreciative of your consideration and would ask for a resolution as soon as possible.

Sincerely,

James T. Carkulis
Manager of each of the Project Companies

Cc: Idaho Power Company, Cogeneration and Small Power Production

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 53

DONOVAN E. WALKER
Lead Counsel
dwalker@idahopower.com

June 8, 2012

VIA ELECTRONIC & U.S. CERTIFIED MAIL
RETURN RECEIPT REQUESTED

James Carkulis
Exergy Development Group
802 West Bannock Street, 12th Floor
Boise, Idaho 83702

Re: Jack Ranch Projects – Your Letter Dated June 1, 2012

Dear Mr. Carkulis:

This letter responds to your letter dated June 1, 2012, to Lisa Grow wherein you again make a request that Idaho Power Company ("Idaho Power") agree to extend the June 30, 2012, Scheduled Operation Dates that you selected and obligated your projects to in the Firm Energy Sales Agreements ("FESAs") for each of the Jack Ranch Projects (i.e., Cottonwood Wind Park, Deep Creek Wind Park, Rogerson Flats Wind Park, and Salmon Creek Wind Park). As we have previously communicated to you, Idaho Power does not agree to extend those dates.

Your most recent allegation that Idaho Power agreed to a December 2011 on-line date from a generator interconnection standpoint and that you relied on Idaho Power's representation of a December 2011 generator interconnection date is absolutely without merit. December 2011 was the date selected by the Exergy Development Group ("Exergy") when it submitted its Small Generator Interconnection Request Application Forms and the Interconnection Request for a Large Generating Facility on March 12, 2010. Importantly, Exergy submitted five generator interconnection requests on March 12, 2010. GI 322, 223, 324, and 235 were each for 20 megawatt ("MW") projects and GI 327 was for a single 200 MW project. Exergy subsequently withdrew the requests for GI 322, 323, and 324, leaving GI 325 and GI 327.

The Generator Interconnection Feasibility Study provided to Exergy for GI 325 and 327 by Idaho Power on July 28, 2010 ("Feasibility Study"), states "The proposed in-service date is December, 2011." This statement is merely a factual recital of the in-

1221 W. Idaho St. (83702)
P.O. Box 70
Boise, ID 83707

service date requested by Exergy when it submitted its generator interconnection application forms for the Jack Ranch Projects. The same is true with the Generator Interconnection System Impact Study provided to you by Idaho Power on December 29, 2010 ("System Impact Study"), which states, "The proposed in-service date for this project is December, 2011." Again, this language was included as a mere recitation of what Exergy requested when it submitted its generator interconnection forms. Nowhere in those documents does Idaho Power represent, let alone agree, that the generator interconnection facilities for the Jack Ranch Projects would be constructed and on-line by December 2011. Indeed, Idaho Power has never represented to Exergy that the Jack Ranch Projects would be on-line by December 2011.

In fact, Idaho Power communicated to you on multiple occasions, both verbally and in writing, that Exergy was proceeding at its own risk in signing FESAs in December 2010 with a Scheduled Operation Date of June 30, 2012, prior to Idaho Power completing the necessary generator interconnection and transmission studies to determine how long it would take to construct and/or upgrade such facilities as well as the cost of such facilities. Specifically, in a letter dated November 17, 2010 (nearly one month prior to you executing the FESAs) to Exergy's attorney, Peter J. Richardson, Idaho Power told Exergy that:

> It was Idaho Power's understanding that Mr. Carkulis wished to get the results of the required interconnection and transmission studies, which will identify the need for and cost of interconnection facilities and possible transmission upgrades, prior to the time at which he would sign a Firm Energy Sales Agreement ("FESA") which would obligate the projects to a Scheduled Operation Date. As you are aware, the FESA contains provisions providing for delay damages should the projects fail to meet the Scheduled Operation Date set forth in the FESA. These delay damages are secured by the requirement to post liquid delay damage security thirty (30) days subsequent to IPUC approval of the FESA. As you are also aware, it is your client's responsibility to work with Idaho Power's Delivery business unit to ensure that sufficient time and resources will be available for Delivery to construct the interconnection facilities, and transmission upgrades if required, in time to allow the projects to achieve the Scheduled Operation Date set forth in the FESA. As Mr. Carkulis has previously been advised, delays in the interconnection or transmission process do not constitute excusable delays in achieving the Scheduled Operation Date, and, if the projects fail to achieve the Scheduled Operation Date at the times specified in the FESA, delay damages will be assessed. It was for this

> reason that Idaho Power was of the understanding that your client was not yet ready to commit to the execution of a FESA.
>
> If this is not the case, and if your client wishes to proceed forward with the execution of a FESA prior to completion of the interconnection and transmission studies and accept the associated risk thereto, then Idaho Power can send you a draft PURPA Wind FESA that contains the most recent and up-to-date "standard" terms and conditions that have been approved by the IPUC.

Letter from Donovan E. Walker to Peter J. Richardson dated November 17, 2010, at pp. 1-2.

On November 23, 2010, Exergy's attorney responded to Idaho Power's November 17, 2010, letter by stating:

> As you requested, I write to confirm that Exergy, as the developer for [the Jack Ranch Projects], is willing to sign contracts including the standard $45/kw delay liquidated damages clause prior to completion of the entire interconnection and transmission process for these projects, including Idaho Power internal processes required to designate the resource as a network resource. Exergy understands that, under the current standard contract Idaho Power would agree to enter into, a delay in achieving the online date caused by the interconnection or transmission processes is a delay which will not excuse a possible trigger in the delay damages clause.

Letter from Peter J. Richardson to Donovan E. Walker dated November 23, 2010.

The very next day, on November 24, 2010, Idaho Power sent draft FESAs to Exergy's attorney, including a cover letter which stated, in part:

> Your letter also confirms and acknowledges that your client wishes to move forward with the FESA, including the standard, Idaho Public Utilities Commission ("Commission") approved $45 per kilowatt of project capacity delay security, prior to completion of the interconnection and transmission studies and processes. Further, that your client understands it is their responsibility to work with Idaho Power's Delivery business unit to ensure that sufficient time and resources will

> be available for Delivery to construct the interconnection facilities, and transmission upgrades if required, in time to allow the projects to achieve the Scheduled Operation Date that the projects will commit themselves to in the FESA. In addition, your client has been advised, and accepts the risk, that delays in the interconnection or transmission process do not constitute excusable delays in achieving the Scheduled Operation Date, and if the projects fail to achieve the Scheduled Operation Date at the times specified in the FESA, delay damages will be assessed, and delay security applied. Please allow me to suggest that special consideration be given to the Scheduled Operation Date selected by the projects for inclusion and the FESA, such that with the information available at this time a date is chosen that has a good probability of providing time for the anticipated interconnection and possible transmission upgrades to be completed.

Letter from Donovan E. Walker to Peter J. Richardson dated November 24, 2010.

In response, Exergy's attorney sent a letter stating, in part:

> Exergy is fully aware of the contracts' provisions and, as you know has successfully developed many projects using the standard Idaho Power contract. Exergy is also fully aware of transmission and interconnection risks, as well as the liquid security provision.

Letter from Peter J. Richardson to Donovan E. Walker dated November 29, 2010.

This series of correspondence demonstrates that not only did Exergy have actual notice of the risks associated with selecting a Scheduled Operation Date in the FESAs without knowing the time frames or costs associated with interconnection and transmission facilities for the Jack Ranch Projects, Exergy affirmatively acknowledged and accepted those risks. With actual knowledge and affirmative acceptance of these risks, Exergy selected a Scheduled Operation Date of June 30, 2012, in each of the FESAs, which Exergy executed on December 10, 2010, and which were ultimately approved by the Idaho Public Utilities Commission on February 11, 2011.

In addition, as a sophisticated developer of generation projects and having previously developed more than a dozen other PURPA QF wind projects on Idaho Power's system, Exergy is fully aware of the studies Idaho Power must conduct as well as the processes necessary for generators, such as the Jack Ranch Projects, to connect to Idaho Power's system. In addition, Exergy is fully aware from its previous development projects with Idaho Power that the factual recitation of the proposed dates by a generator contained in the Feasibility Study and System Impact Study are in no way a guarantee by Idaho Power nor even a representation by Idaho Power as to when generator interconnection facilities will be on-line.

Further, after executing the FESAs, but prior to Idaho Power issuing the Facilities Study for the Jack Ranch Projects, Exergy requested that Idaho Power make significant changes to the generator interconnection facilities configuration for the Jack Ranch Projects, which required Idaho Power to restudy a large portion of the Jack Ranch Projects. Specifically, on April 12, 2011, Exergy sent Idaho Power a letter requesting several revisions to the Jack Ranch Projects, including reducing Exergy's GI 327 from 200 MW to 84 MW with an option to reduce the interconnection even further to 63 MW at some point in the future. Further, Exergy requested that the point of interconnection for the Cottonwood Wind Park, Deep Creek Wind Park and Rogerson Flats Wind Park be changed from an Idaho Power 138 kilovolt ("kV") line to a 345 kV line. Idaho Power responded via letter dated April 27, 2011, that a request of this type required Idaho Power to conduct a material modification review under Idaho Power's Large Generator Interconnection Procedures. Idaho Power further clarified that the change in the voltages from 138 kV to 345 kV for three of the four Jack Ranch Projects would require a restudy of the Facilities Study that was then in progress due to the different integration voltages and the associated different Idaho Power transmission lines. *See* letter dated May 20, 2011, from Dave Angell to James Carkulis. These significant changes requested by Exergy caused delays in the Jack Ranch Project's generator interconnection process.

Idaho Power is disappointed in reviewing your June 1, 2012, letter in that it contains many known misstatements of fact in an attempt to contend that Idaho Power, and not Exergy, was responsible for any delay that has occurred and the ultimate failure of Exergy to meet the Scheduled Operation Date that Exergy set for itself. Your letter is a transparent attempt to now, at this late hour, set up legal claims against Idaho Power that have no merit, while purporting to proceed in good faith and in a commercially reasonable manner. For example, at the end of your June 1 letter you state "each of the Project Companies has made, in good faith and based on the information provided by Idaho Power Company in the aforementioned studies, the applicable security deposits with the assumption that Idaho Power Company would be able to construct the interconnection facilities on the schedule originally set by the interconnection studies." This statement is incorrect.

First, Exergy has completely failed to, and has not to this day, paid the required construction deposit, nor executed the required Generator Interconnection Agreement ("GIA") in order for Idaho Power to proceed with any of the required detailed design, engineering, ordering of materials, and construction of the interconnection facilities and/or transmission upgrades. What Exergy has paid are the required deposits for Idaho Power to conduct the mandatory studies (Feasibility Study, System Impact Study, and Facilities Study), none of which provide a valid time line unless and until Exergy executes the required GIA and pays the requisite construction deposit for work to begin. Second, as stated above, as a sophisticated developer of generation projects and having previously developed more than a dozen other PURPA QF wind projects on Idaho Power's system, Exergy is fully aware of the studies Idaho Power must conduct as well as the processes necessary for generators, such as the Jack Ranch Projects, to connect to Idaho Power's system. Exergy is fully aware that the recitation in Section 4 of the Feasibility Study Report of what Exergy requested as an on-line date in its Generator Interconnection Application (December 2011) is not a representation by Idaho Power that the required work – which at the Feasibility Study stage is still unknown – can be accomplished by any date certain.

Additionally, even if Idaho Power were to agree, which it certainly does not, to change the Scheduled Operation Date in the FESAs, you have requested December 1, 2012, as the new Scheduled Operation Date. Further you state that this December 2012 date is consistent with the interconnection agreements applicable to each Project. The December 2012 date is most definitely NOT consistent with the anticipated time line, construction, and upgrades required of the interconnection of the Jack Ranch Projects. As clearly stated in the final GIA transmitted to you on May 14, 2012, "Idaho Power does not commit to this date [December 15, 2012] but will use reasonable efforts to have commissioning complete by 6/9/2014." Consequently, your requested change in the Scheduled Operation Date, even if agreeable to Idaho Power, would not resolve the problem that exists today, with Exergy insisting upon a Scheduled Operation Date that is before the time at which the Jack Ranch Projects' interconnection could be completed.

Lastly, as a reminder, per the May 14, 2012, letter to you from Idaho Power's Tess Park, "Failure to submit an executed copy of the enclosed Final GIA, which includes the estimated milestones for the completion of construction, and complete the necessary financing arrangements for the Jack Ranch Projects **by June 13, 2012,** will result in Idaho Power terminating your generator interconnection request and withdrawing the Jack Ranch Projects from the generator interconnection queue."

Sincerely,

Donovan E. Walker

DEW:csb
cc: Lisa Grow, Idaho Power (via e-mail)
Tess Park, Idaho Power (via e-mail)
Randy, Allphin, Idaho Power (via e-mail)
Jason Williams, Idaho Power Corporate Counsel (via e-mail)

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 54

Williams, Jason

From: Walker, Donovan
Sent: Tuesday, June 12, 2012 2:26 PM
To: Williams, Jason; Park, Tessia
Subject: FW: Jack Ranch GIA

From: James Carkulis [mailto:jcarkulis@exergydevelopment.com]
Sent: Tuesday, June 12, 2012 2:22 PM
To: Harris, Joshua; Walker, Donovan; PdelVecchio@mcguirewoods.com; Dunn, Walter J.; peter@richardsonandoleary.com; Dustin Shively
Subject: Jack Ranch GIA

Joshua:

Per our request of a month ago on the Jack Ranch GIA, I had not only asked that the GIA emulate the Thousand Springs language, but also the Idaho Power Large Generator Interconnection Agreement language which allows the potential of self-build. We spoke of this at the last meeting and I said I would provide clarity.

Given the fact that one of our partners has built or been involved in around 60% of all wind park substations and upgrades in the USA, we are confident of the need to include this provision in the Jack Ranch GIA. We have full confidence that once executed Idaho Power shall use all of its resources to comply with our timing, but we need an additional element for our financial partners.

The IPCo approved language we seek to have inserted is as follows:

5.1.3 **Option to Build.** If the dates designated by Interconnection Customer are not acceptable to Transmission Provider, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days, and unless the Parties agree otherwise, Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.2. Transmission Provider and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

Thank you.

James

James T. Carkulis
802 W Bannock, 12th Floor Boise, ID 83702
Office: 208.336.9793 | Mobile: 406.459.3013
www.exergydevelopment.com

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 55

IDAHO POWER®
An IDACORP Company

DONOVAN E. WALKER
Lead Counsel
dwalker@idahopower.com

June 12, 2012

VIA ELECTRONIC & U.S. CERTIFIED MAIL
RETURN RECEIPT REQUESTED

James Carkulis
Exergy Development Group
802 West Bannock Street, 12th Floor
Boise, Idaho 83702

Re: Jack Ranch Projects – Your June 12, 2012, E-Mail to Josh Harris

Dear Mr. Carkulis:

This letter responds to your e-mail of June 12, 2012, to Idaho Power's Josh Harris. As we have discussed several times and as you are fully aware, Idaho Power's Tariff Schedule 72 is the governing Tariff/document for PURPA QF Generator Interconnections to Idaho Power's system. Schedule 72 provides that "The Company [Idaho Power] will construct, own, operate and maintain all equipment, Upgrades and Relocations on the Company's electrical side of the Interconnection Point." IPUC No. 29, Tariff No. 101, Sheet No. 72-7. Schedule 72 does incorporate many provisions of the FERC-approved Large Generator and Small Generator Interconnection Procedures in the State Schedule 72 process. *See* IPUC No. 29, Tariff No. 101, Sheet No. 72-3, sub. 2. Only those provisions of the LGIA and SGIA that are not addressed by Schedule 72 are applicable in this state jurisdictional generator interconnection process. Any provisions of the LGIA and/or SGIA that purport to allow a QF project to construct any facilities used in any way to serve any other Idaho Power customer "on the Company's electrical side of the Interconnection Point" are not applicable as Schedule 72 requires such facilities to be constructed, owned, operated, and maintained by Idaho Power. We have specifically discussed this requirement on more than one occasion in our face-to-face meetings regarding your Jack Ranch projects, as well as several of your other projects with Idaho Power.

Additionally, the provision you cite to in the LGIA (5.1.3) – if it were applicable in this situation – applies only to Stand Alone Network Upgrades. As mentioned above, and as discussed with you previously, any facilities that are involved with the provision of service by Idaho Power to any other customers are not Stand Alone Upgrades, and must be constructed by Idaho Power pursuant to Schedule 72. This includes the interconnection facilities and upgrades for the Jack Ranch projects.

Further, as we discussed and as you requested, specific language consistent with what Idaho Power has contracted for with other QF interconnections – specifically the Thousand Springs GIA – was included in the final GIA, which we provided to you on May 14, 2012. Those additional provisions would allow Idaho Power to work cooperatively with you and bring to bear the assistance of third-party contractors and other methods to reasonably expedite the required work for your interconnection and upgrades. The Thousand Springs GIA language that you referenced is as follows:

> This is a revised date, upward in time from 1/15/11, based upon Interconnection Customer's needs and requests. Idaho Power will use reasonable efforts to have IPC's commissioning completed by 12/31/10. This revised completion date is contingent upon all materials being delivered on their scheduled delivery dates, the transmission line outage occurring as scheduled, receiving all necessary local, state and federal permits, including FERC and NEPA, and construction & regional resources being available.
>
> The parties hereby acknowledge that Idaho Power shall not be liable for any possible damages associated in any way with Renewable Energy Credits or Attributes, the firm energy sales agreements, and the like, attributable to Interconnection Customer, or any of the various projects named on page one of the GIA, should the 12/30/10 date not be met.
>
> Under normal efforts to bring the projects online a normal amount of overtime is utilized. Because of the Interconnection Customer's desire to meet an IPC commissioning date of 12/31/10, Interconnection Customer hereby authorizes IPC to incur additional expenses, including additional overtime, lodging, travel, and other expenses needed to bring in other IPC resources and personnel from other IPC regions as necessary to work on this interconnection.

The corresponding language that appears in the Jack Ranch GIA is as follows:

> Customer has requested an in-service date of 12/15/2012. Idaho Power does not commit to this date but will use reasonable efforts to have commissioning complete by

> 6/9/2014. This date is contingent upon all materials being delivered in a timely manner, as well as other factors, some of which are described above. The parties hereby acknowledge that Idaho Power shall not be liable to for any possible damages associated in any way with Renewable Energy Credits or Attributes, tax credits, the firm energy sales agreements, and the like, attributable to Customer, or any of the various projects named on page one of this GIA, should the 6/9/2014 date not be met.
>
> Under normal efforts to bring the projects online a normal amount of overtime is utilized. Because of the Customer's desire to meet an IPC commissioning prior to 6/9/2014, Customer hereby authorizes IPC to incur additional expenses, including additional overtime, lodging, travel, and other expenses needed to bring in other IPC resources and personnel from other IPC regions, or to utilize third party contractors, as necessary to work on this interconnection.

As evidenced by the language quoted above and included in the Final GIA for the Jack Ranch projects, as long as Exergy is willing to pay the associated additional cost, Idaho Power will use commercially reasonable efforts – including additional resources of its own, third-party contractors, and other steps to expedite the required interconnection work. However, as has been previously communicated to you in writing, even with the use of such measures to expedite, Idaho Power's estimate is a minimum of 18 months from payment of funds and execution of the Final GIA to complete the necessary system upgrades and interconnection facilities. As stated in Idaho Power's April 13, 2012, letter to you:

> As stated, Idaho Power will use commercially reasonable efforts, and work with you to expedite the construction of your interconnection facilities, including the use of third-party contractors – and including additional costs – if authorized and borne entirely by Exergy – to expedite the work required to interconnect your project to Idaho Power's system, allowing its energization. However, so as to be clear, I must reiterate that this does not change Idaho Power's estimate of a minimum of 18 months from payment of funds and execution of the GIA to complete the necessary system upgrades and interconnection facilities required to energize your project on Idaho Power's system, and even given the other uncertainties involved, it could take longer than 18 months still.

Your comment and request to include a provision consistent with the Thousand Springs GIA was received by Idaho Power during the appropriate 30-day comment period on the Jack Ranch Draft GIA. Idaho Power has incorporated your requested language into the Jack Ranch Final GIA to extent that Schedule allows. Your additional request at this late hour to include language from Idaho Power's LGIA is not only inappropriate, as the time for comment on the Draft GIA has passed, but it also has been previously and specifically discussed, addressed, resolved. Unfortunately, your request in your most recent e-mail appears to be another transparent attempt to now set up legal claims against Idaho Power that have no merit, while purporting to proceed in good faith and in a commercially reasonable manner – similar to those referenced in Idaho Power's June 8 letter to you.

Finally, as a reminder, pursuant to the May 14, 2012, letter to you from Idaho Power's Tess Park, and confirmed by Idaho Power's letter dated June 8, 2012, and now this letter as well, "Failure to submit an executed copy of the enclosed Final GIA, which includes the estimated milestones for the completion of construction, and complete the necessary financing arrangements for the Jack Ranch Projects **by June 13, 2012,** will result in Idaho Power terminating your generator interconnection request and withdrawing the Jack Ranch Projects from the generator interconnection queue."

Sincerely,

Donovan E. Walker

DEW:csb
cc: Lisa Grow, Idaho Power (via e-mail)
Tess Park, Idaho Power (via e-mail)
Randy Allphin, Idaho Power (via e-mail)
Jason Williams, Idaho Power Corporate Counsel (via e-mail)

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 56

received ON 6-13-12
at 4:57 p.m. by
Christa Bearry
Christa Bearry

RECEIVED
JUN 13 2012
By CB-Idaho Power

June 13, 2012

GENERATOR INTERCONNECTION AGREEMENT
Schedule 72 (PURPA)

For the
JACK RANCH WIND PROJECTS

SALMON CREEK WIND (#325) 20 MW
JACK RANCH WIND (#327) 60 MW

80 MW TOTAL

TABLE OF CONTENTS

This Generator Interconnection Agreement ("Agreement") under Idaho Power Company's Schedule 72 is effective as of the 14 day of June, 2012 between Energy Development Group of Idaho, LLC ("Seller", "Customer" or "The Project") and Idaho Power Company ("Company","Transmission Owner", "Idaho Power", "IPC" or "IPCO").

RECITALS

A. Seller will own or operate a Generation Facility that qualifies for service under Idaho Power's Commission-approved Schedule 72 and any successor schedule.

B. The Generation Facility covered by this Agreement is more particularly described in Attachment 1.

AGREEMENTS

1. Capitalized Terms
Capitalized terms used herein shall have the same meanings as defined in Schedule 72 or in the body of this Agreement.

2. Terms and Conditions
This Agreement and Schedule 72 provide the rates, charges, terms and conditions under which the Seller's Generation Facility will interconnect with, and operate in parallel with, the Company's transmission/distribution system. Terms defined in Schedule 72 will have the same defined meaning in this Agreement. If there is any conflict between the terms of this Agreement and Schedule 72, Schedule 72 shall prevail.

3. This Agreement is not an agreement to purchase Seller's power.
Purchase of Seller's power and other services that Seller may require will be covered under separate agreements. Nothing in this Agreement is intended to affect any other agreement between the Company and Seller.

4. Attachments
Attached to this Agreement and included by reference are the following:

Attachment 1 – Description and Costs of the Generation Facility, Interconnection Facilities, and Metering Equipment.

Attachment 2 – One-line Diagram Depicting the Generation Facility, Interconnection Facilities, Metering Equipment and Upgrades.

Attachment 3 – Milestones For Interconnecting the Generation Facility.

Attachment 4 – Additional Operating Requirements for the Company's Transmission System Needed to Support the Seller's Generation Facility.

Attachment 5 – Reactive Power.

Attachment 6 – Description of Upgrades required to integrate the Generation Facility and Best Estimate of Upgrade Costs.

5. Effective Date, Term, Termination and Disconnection

5.1 Term of Agreement. Unless terminated earlier in accordance with the provisions of this Agreement, this Agreement shall become effective on the date specified above and remain effective as long as Seller's Generation Facility is eligible for service under Schedule 72.

5.2 Termination.

5.2.1 Seller may voluntarily terminate this Agreement upon expiration or termination of an agreement to sell power to the Company.

5.2.2 After a Default, either Party may terminate this Agreement pursuant to Section 6.5.

5.2.3 Upon termination or expiration of this Agreement, the Seller's Generation Facility will be disconnected from the Company's transmission/distribution system. The termination or expiration of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination. The provisions of this Section shall survive termination or expiration of this Agreement.

5.3 Temporary Disconnection. Temporary disconnection shall continue only for so long as reasonably necessary under "Good Utility Practice." Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region. Good Utility Practice includes compliance with WECC or NERC requirements. Payment of lost revenue resulting from temporary disconnection shall be governed by the power purchase agreement.

5.3.1 Emergency Conditions. "Emergency Condition" means a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of the Company, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Company's transmission/distribution system, the Company's Interconnection Facilities or the equipment of the Company's customers; or (3) that, in the case of the Seller, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the reliability and security of, or damage to, the Generation Facility or the Seller's Interconnection Facilities. Under Emergency Conditions, either the Company or the Seller may immediately suspend interconnection service and temporarily disconnect the Generation Facility. The Company shall notify the Seller promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Seller's operation of the Generation Facility. The Seller shall notify the Company promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Company's equipment or service to the Company's customers. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of both Parties' facilities and operations, its anticipated duration, and the necessary corrective action.

5.3.2 Routine Maintenance, Construction, and Repair. The Company may interrupt interconnection service or curtail the output of the Seller's Generation Facility and temporarily disconnect the Generation Facility from the Company's *transmission/distribution system when necessary for routine maintenance, construction, and repairs on the Company's transmission/distribution system. The Company will make a reasonable attempt to contact the Seller prior to exercising its rights to interrupt interconnection or curtail deliveries from the Seller's Facility. Seller understands that in the case of emergency circumstances, real time operations of the electrical system, and/or unplanned events, the Company may not be able to provide notice to the Seller prior to interruption, curtailment or reduction of electrical energy deliveries to the Company. The Company shall use reasonable efforts to coordinate such reduction or temporary disconnection with the Seller.*

5.3.3 Scheduled Maintenance. On or before January 31 of each calendar year, Seller shall submit a written proposed maintenance schedule of significant Facility maintenance for that calendar year and the Company and Seller shall mutually agree as to the acceptability of the proposed schedule. The Parties determination as to the acceptability of the Seller's timetable for scheduled maintenance will take into consideration Good Utility Practices, Idaho Power system requirements and the Seller's preferred schedule. Neither Party shall unreasonably withhold acceptance of the proposed maintenance schedule.

5.3.4. Maintenance Coordination. The Seller and the Company shall, to the extent practical, coordinate their respective transmission/distribution system and Generation Facility maintenance schedules such that they occur simultaneously. Seller shall provide and maintain adequate protective equipment sufficient to prevent damage to the Generation Facility and Seller-furnished Interconnection Facilities. In some cases, some of Seller's protective relays will provide back-up protection for Idaho Power's facilities. In that event, Idaho Power will test such relays annually and Seller will pay the actual cost of such annual testing.

5.3.5 Forced Outages. During any forced outage, the Company may suspend interconnection service to effect immediate repairs on the Company's transmission/distribution system. The Company shall use reasonable efforts to provide the Seller with prior notice. If prior notice is not given, the Company shall, upon request, provide the Seller written documentation after the fact explaining the circumstances of the disconnection.

5.3.6 Adverse Operating Effects. The Company shall notify the Seller as soon as practicable if, based on Good Utility Practice, operation of the Seller's Generation Facility may cause disruption or deterioration of service to other customers served from the same electric system, or if operating the Generation Facility could cause damage to the Company's transmission/distribution system or other affected systems. Supporting documentation used to reach the decision to disconnect shall be provided to the Seller upon request. If, after notice, the Seller fails to remedy the adverse operating effect within a reasonable time, the Company may disconnect the Generation Facility. The Company shall provide the Seller with reasonable notice of such disconnection, unless the provisions of Article 5.3.1 apply.

5.3.7 Modification of the Generation Facility. The Seller must receive written authorization from the Company before making any change to the Generation Facility that may have a material impact on the safety or reliability of the Company's transmission/distribution system. Such authorization shall not be unreasonably withheld. Modifications shall be done in accordance with Good Utility Practice. If the Seller makes *such modification without the Company's prior written authorization, the latter shall have the right to temporarily disconnect the Generation Facility.*

5.3.8 Reconnection. The Parties shall cooperate with each other to restore the Generation Facility, Interconnection Facilities, and the Company's transmission/distribution system to their normal operating state as soon as reasonably practicable following a temporary disconnection.

5.3.9 Voltage Levels. Seller, in accordance with Good Utility Practices, shall minimize voltage fluctuations and maintain voltage levels acceptable to Idaho Power. Idaho Power may, in accordance with Good Utility Practices, upon one hundred eighty (180) days' notice to the Seller, change its nominal operating voltage level by more than ten percent (10%) at the Point of Delivery, in which case Seller shall modify, at Idaho Power's expense, Seller's equipment as necessary to accommodate the modified nominal operating voltage level.

5.4 Land Rights.

5.4.1 Seller to Provide Access. Seller hereby grants to Idaho Power for the term of this Agreement all necessary rights-of-way and easements to install, operate, maintain, replace, and remove Idaho Power's Metering Equipment, Interconnection Equipment, Disconnection Equipment, Protection Equipment and other Special Facilities necessary or useful to this Agreement, including adequate and continuing access rights on property of Seller. Seller warrants that it has procured sufficient easements and rights-of-way from third parties so as to provide Idaho Power with the access described above. All documents granting such easements or rights-of-way shall be subject to Idaho Power's approval and in recordable form.

5.4.2 Use of Public Rights-of-Way. The Parties agree that it is necessary to avoid the adverse environmental and operating impacts that would occur as a result of duplicate electric lines being constructed in close proximity. Therefore, subject to Idaho Power's compliance with Paragraph 5.4.4, Seller agrees that should Seller seek and receive from any local, state or federal governmental body the right to erect, construct and maintain Seller-furnished Interconnection Facilities upon, along and over any and all public roads, streets and highways, then the use by Seller of such public right-of-way shall be subordinate to any future use by Idaho Power of such public right-of-way for construction and/or maintenance of electric distribution and transmission facilities and Idaho Power may claim use of such public right-of-way for such purposes at any time. Except as required by Paragraph 5.4.4, Idaho Power shall not be required to compensate Seller for exercising its rights under this Paragraph 5.4.2.

5.4.3 Joint Use of Facilities. Subject to Idaho Power's compliance with Paragraph 15.4.4, Idaho Power may use and attach its distribution and/or transmission facilities to Seller's Interconnection Facilities, may reconstruct Seller's Interconnection Facilities to accommodate Idaho Power's usage or Idaho Power may construct its own distribution or transmission facilities along, over and above any public right-of-way acquired from Seller pursuant to Paragraph 5.4.2, attaching Seller's Interconnection Facilities to such newly constructed facilities. Except as required by Paragraph 5.4.4, Idaho Power shall not be required to compensate Seller for exercising its rights under this Paragraph 5.4.3.

5.4.4 Conditions of Use. It is the intention of the Parties that the Seller be left in substantially the same condition, both financially and electrically, as Seller existed prior *to Idaho Power's exercising its rights under this Paragraph 5.4. Therefore, the Parties agree that the exercise by Idaho Power of any of the rights enumerated in Paragraphs 5.4.2 and 5.4.3 shall: (1) comply with all applicable laws, codes and Good Utility Practices, (2) equitably share the costs of installing, owning and operating jointly used facilities and rights-of-way. If the Parties are unable to agree on the method of apportioning these costs, the dispute will be submitted to the Commission for resolution and the decision of the Commission will be binding on the Parties, and (3) shall provide Seller with an interconnection to Idaho Power's system of equal capacity and durability as existed prior to Idaho Power exercising its rights under this Paragraph 5.4.*

6. <u>Assignment, Liability, Indemnity, Force majeure, Consequential Damages and Default</u>.

6.1 <u>Assignment</u>. This Agreement may be assigned by either Party upon twenty-one (21) calendar days prior written notice and opportunity to object by the other Party; provided that:

6.1.1 Either Party may assign this Agreement without the consent of the other Party to any affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement.

6.1.2 The Seller shall have the right to contingently assign this Agreement, without the consent of the Company, for collateral security purposes to aid in providing financing for the Generation Facility, provided that the Seller will promptly notify the Company of any such contingent assignment.

6.1.3 Any attempted assignment that violates this article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same financial, credit, and insurance obligations as the Seller. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

6.2 <u>Limitation of Liability</u>. Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages, except as authorized by this Agreement.

6.3 <u>Indemnity</u>.

6.3.1 This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in Article 6.2.

6.3.2 The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

6.3.3 If an indemnified person is entitled to indemnification under this article as a result of a claim by a third party, and the indemnifying Party fails, after notice and *reasonable opportunity to proceed under this article, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim. Failure to defend is a Material Breach.*

6.3.4 If an indemnifying party is obligated to indemnify and hold any indemnified person harmless under this article, the amount owing to the indemnified person shall be the amount of such indemnified person's actual loss, net of any insurance or other recovery.

6.3.5 Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this article may apply, the indemnified person shall notify the indemnifying party of such fact. Any failure of or delay in such notification shall be a Material Breach and shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party.

6.4 Force Majeure. As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the control of the Seller or of the Company which, despite the exercise of due diligence, such Party is unable to prevent or overcome. Force Majeure includes, but is not limited to, acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, or changes in law or regulation occurring after the Operation Date, which, by the exercise of reasonable foresight such party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome. If either Party is rendered wholly or in part unable to perform its obligations under this Agreement because of an event of Force Majeure, both Parties shall be excused from whatever performance is affected by the event of Force Majeure, provided that:

(1) The non-performing Party shall, as soon as is reasonably possible after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence.

(2) The suspension of performance shall be of no greater scope and of no longer duration than is required by the event of Force Majeure.

(3) No obligations of either Party which arose before the occurrence causing the suspension of performance and which could and should have been fully performed before such occurrence shall be excused as a result of such occurrence.

6.5 Default and Material Breaches.

6.5.1 Defaults. If either Party fails to perform any of the terms or conditions of this Agreement (a "Default" or an "Event of Default"), the nondefaulting Party shall cause notice in writing to be given to the defaulting Party, specifying the manner in which such default occurred. If the defaulting Party shall fail to cure such Default within the sixty (60) days after service of such notice, or if the defaulting Party reasonably demonstrates to the other Party that the Default can be cured within a commercially reasonable time but not within such sixty (60) day period and then fails to diligently pursue such cure, then, the nondefaulting Party may, at its option, terminate this Agreement and/or pursue its legal or equitable remedies.

6.5.2 Material Breaches. The notice and cure provisions in Paragraph 6.6.1 do not apply to Defaults identified in this Agreement as Material Breaches. Material Breaches must be cured as expeditiously as possible following occurrence of the breach.

7. Insurance.
During the term of this Agreement, Seller shall secure and continuously carry the following insurance coverage:

7.1 Comprehensive General Liability Insurance for both bodily injury and property damage with limits equal to $1,000,000, each occurrence, combined single limit. The deductible for such insurance shall be consistent with current Insurance Industry Utility practices for similar property.

7.2 The above insurance coverage shall be placed with an insurance company with an A.M. Best Company rating of A- or better and shall include:

(a) An endorsement naming Idaho Power as an additional insured and loss payee as applicable; and

(b) A provision stating that such policy shall not be canceled or the limits of liability reduced without sixty (60) days' prior written notice to Idaho Power.

7.3 Seller to Provide Certificate of Insurance. As required in Paragraph 7 herein and annually thereafter, Seller shall furnish the Company a certificate of insurance, together with the endorsements required therein, evidencing the coverage as set forth above.

7.4 Seller to Notify Idaho Power of Loss of Coverage - If the insurance coverage required by Paragraph 7.1 shall lapse for any reason, Seller will immediately notify Idaho Power in writing. The notice will advise Idaho Power of the specific reason for the lapse and the steps Seller is taking to reinstate the coverage. Failure to provide this notice and to expeditiously reinstate or replace the coverage will constitute grounds for a temporary disconnection under Section 5.3 and will be a Material Breach.

8. Miscellaneous.

8.1 Governing Law. The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of Idaho without regard to its conflicts of law principles.

8.2 Salvage. No later than sixty (60) days after the termination or expiration of this Agreement, Idaho Power will prepare and forward to Seller an estimate of the remaining value *of those Idaho Power furnished Interconnection Facilities as required under Schedule 72 and/or described in this Agreement, less the cost of removal and transfer to Idaho Power's nearest warehouse, if the Interconnection Facilities will be removed. If Seller elects not to obtain ownership of the Interconnection Facilities but instead wishes that Idaho Power reimburse the Seller for said Facilities the Seller may invoice Idaho Power for the net salvage value as estimated by Idaho Power and Idaho Power shall pay such amount to Seller within thirty (30) days after receipt of the invoice. Seller shall have the right to offset the invoice amount against any present or future payments due Idaho Power.*

8.3 Option to Build. If the dates designated by Seller are not acceptable to Idaho Power, Idaho Power shall so notify Seller within thirty (30) calendar days, and unless the Parties agree otherwise, Seller shall have the option to assume responsibility for the design, procurement and construction of Idaho Power's Interconnection Facilities and any related or necessary Upgrades, Special Facilities, and Network Upgrades.

9. Notices.

9.1 General. Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national currier service, or sent by first class mail, postage prepaid, to the person specified below:

If to the Seller:

Seller: XRG Devleopment Partners ____________
Attention: Elizabeth Woolstenhulme ____________
Address: 802 W. Bannock, 12th Floor ____________
City ____________ State: ________ Zip: ________
Phone: ____________ Fax: ____________

If to the Company:
Idaho Power Company - Delivery
Attention: Load Serving Operations Director
1221 W. Idaho Street
Boise: Idaho 83702
Phone: 208-388-2360 Fax: 208-388-5504

9.2 Billing and Payment. Billings and payments shall be sent to the addresses set out below:

Seller: XRG Development Partners, LLC ____________
Attention: Elizabeth Woolstenhulme ____________
Address: 802 W. Bannock St, 12th Floor ____________
City: ____________ State: ________ Zip: ________
Phone: ____________ Fax: ____________

Idaho Power Company - Delivery
Attention: Corporate Cashier
PO Box 447
Salt Lake City Utah 84110-0447
Phone: 208-388-5697 email: asloan@idahopower.com

9.3 Designated Operating Representative. The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Seller's Operating Representative:

Seller: TBD
Attention: __________
Address: __________
City: __________ State: ______ Zip: ______
Phone: __________ Fax: __________

Company's Operating Representative:

Idaho Power Company - Delivery
Attention: Outage Coordinator – System/Regional Dispatch
1221 W. Idaho Street
Boise, Idaho 83702
phone 208-388-2861 during regular business hours
After hours -- System Dispatch 388 2826

9.5 Changes to the Notice Information. Either Party may change this information by giving five (5) Business Days written notice prior to the effective date of the change.

10. Signatures.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For the Seller

Name: [signature]

Title: MANAGER

Date: 13-JUNE-2013

For the Company

Name: __________

Title: Load Serving Operations Director – Idaho Power Company

Date: __________

Attachment 1

Description and Costs of the Generation Facility, Interconnection Facilities and Metering Equipment

Interconnection Details

Type of Interconnection Service:	Studied as an Idaho Power Network Resource under PURPA
Full Output:	80 MW
Nominal Delivery Voltage:	345 kV
Affected Parties:	NV Energy (NVE)

General Facility Description

The proposed generation projects consist of up to a total of 80MW of wind generated capacity provided by 10 ea. 2.0 MW Gamesa G97 generators. The projects are split into four Public Utility Regulatory Policies Act (PURPA) projects, each owning a separate Generation Facility as follows: Cottonwood Wind Park, Deep Creek Wind Park, Rogerston Flats Wind Park, and Salmon Creek Wind Park, The total net project ("Jack Ranch Wind Park") at the Interconnection Point is 80 MW.

The location of a new substation owned by the Interconnection Customer would be on private property in the SW1/4 of T14SR16E Section 29 near structures 15-3 and 15-4. Idaho Power will build and own the new substation and control building that will share Idaho Power and NV Energy relay and communications equipment. The new substation will be the third line terminal on the existing Line #803 Midpoint to Humboldt 345 kV transmission line and will be solely utilized to interconnect the Interconnection Customer to the Idaho Power transmission system.

Interconnection Point

The Interconnection Point for Wind Projects #325 (Rogerson Flats, Cottonwood, Deep Creek) and #327 (Salmon Creek) will be at Idaho Power Company's substation on the transformer side of the disconnect switch labeled 301B. A drawing identifying the Point of Interconnection is included as Attachment 2. The Point of Change of Ownership is electrically the same as the Interconnection Point.

Seller's Interconnection Facilities

The Seller will install generators, step-up transformers, distribution collector system, step-up substation, 34.5 kV to 345 kV transformer and associated auxiliary equipment at the project location connecting the project to the Midpoint – Humboldt 345kV line. The Interconnection Customer will build, own, and maintain facilities electrically located on the Interconnection Customer's side of the Point of Change of Ownership.

The Seller will install equipment to receive signals from Idaho Power Company Grid Operations for Generator Output Limit Control ("GOLC") - see Attachment 4 Operating Requirements.

The Seller will provide phone service to IPCo's generator interconnect package as described in *Telecommunications* below.

The Seller will provide a DNP 3.0 serial data connection to the local Idaho Power Company SCADA RTU when any communication with Seller-owned and maintained equipment is required for GOLC, voltage control or other plant monitoring or control. Preliminary points lists and functional description were provided to the Seller in the Facility Study Report.

All interconnection equipment electrically located on the generator side of the Point of Change Ownership shall be owned and maintained by the Seller.

Other Facilities Provided by Seller

Telecommunications

In addition to communication circuits that may be needed by the Seller, the Seller shall provide the following communication circuits for Idaho Power's use:

1. One POTS (Plain Old Telephone Service) dial-up circuit for revenue metering at the generation interconnection site.
2. One DDS (Digital Data Service) circuit guaranteed minimum data rate of 19,200 bits per second for SCADA between the generation interconnection site and Idaho Power Company's Boise Bench facility. The data circuit type shall be one of the following types:
   a. DDS (Digital Data Service). Please note that Frame Relay Service is not acceptable.
   b. 4-wire voice grade analog data circuit (i.e. Qwest VG36).
3. One data circuit (guaranteed minimum data rate of 19,200 bits per second) for <u>each</u> required Phasor Measurement Unit (PMU) between the generation interconnection site and IPC's Boise Bench facility. The data circuit type shall be one of the following types:
   a. DDS (Digital Data Service). Please note that Frame Relay Service is not acceptable.
   b. 4-wire voice grade analog data circuit (e.g. Qwest VG36).

The Seller is required to coordinate with the local communications provider to provide the communications circuits and pay the associated one-time setup and monthly charges. The communication circuits will need to be installed and operational prior to generating into Idaho Power system. Note that installation by the local communications provider may take several months and should be ordered in advance to avoid delaying the project. If the communication circuit types listed above are not available at the site by the local communications provider, the Seller shall confer with Idaho Power.

If high voltage protection is required by the local communications provider for the incoming cable, the high voltage protection assembly shall be engineered and supplied by the Seller. Options are available for indoor or outdoor mounting. The high voltage protection assembly shall be located in a manner that provides Idaho Power 24-hour access to the assembly for communications trouble-shooting of Idaho Power owned equipment.

Seller responsible for the installation of the above mentioned telecommunications if the interconnection is to be operational prior to the microwave path operation.

Ground Fault Equipment
The permissible winding configuration of the interconnect transformer is dependent on the application but shall provide a source of ground current for transmission relaying and the transmission system.

Ground Fault Equipment
The Seller will install transformer configurations that will limit the contribution of ground fault current to 20 amps or less at the Interconnection Point. Additionally, the high side of the step up transformers must be grounded-wye.

Easements/Ownership
The Seller will provide to Idaho Power Company a surveyed (Metes & Bounds) legal description along with exhibit map for Idaho Power facilities. After the legal description has been delivered to IPCO for review, the Seller will supply IPCO an executed deed conveying satisfactory fee title to Idaho Power for the land site for the substation and communication facilities. IPCO construction will not proceed until the appropriate easements and title are secured.

Generator Output Limit Control
The Seller will install equipment to receive signals from Idaho Power Grid Operations for Generation Output Limit Control ("GOLC") - see Attachment 4 Operating Requirements.

Local Service
The Seller is responsible to arrange for local service to the control building for use by both the Seller and Idaho Power.

Property, Site Work and Station Building
The Seller will secure and transfer ownership of the property to Idaho Power Company for the substation and communication facilities to be built by Idaho Power, as referenced in Easements/Ownership (above).

A building within the substation will have a separate, lockable room allocated for NV Energy facilities. The substation and communication facilities will be owned and maintained by Idaho Power Company.

Idaho Power Company's Interconnection Facilities

Idaho Power Company will install a short 345 kV transmission tap between the existing Line #803 Midpoint to Humboldt 345 kV transmission line and the Idaho Power-owned substation. The tap is assumed to be approximately 600 feet long or less. A dead-end structure, 345 kV circuit breaker, two air break switches, and associated relaying, control, communications and metering equipment in the substation yard and building up to the Point of Change of Ownership will be installed. See single line drawing Attachment 2.

Idaho Power will install a 34.5kV metering package for each of the four wind parks. They will be overhead or underground equipment as specified by the Seller. The primary total metering will be done at 345kV at the Idaho Power-owned substation

All interconnection equipment electrically located on the utility side of the Interconnection Point shall be owned, operated, and maintained by Idaho Power.

Estimated Cost & Ownership

The following good faith estimates are provided in 2011 dollars

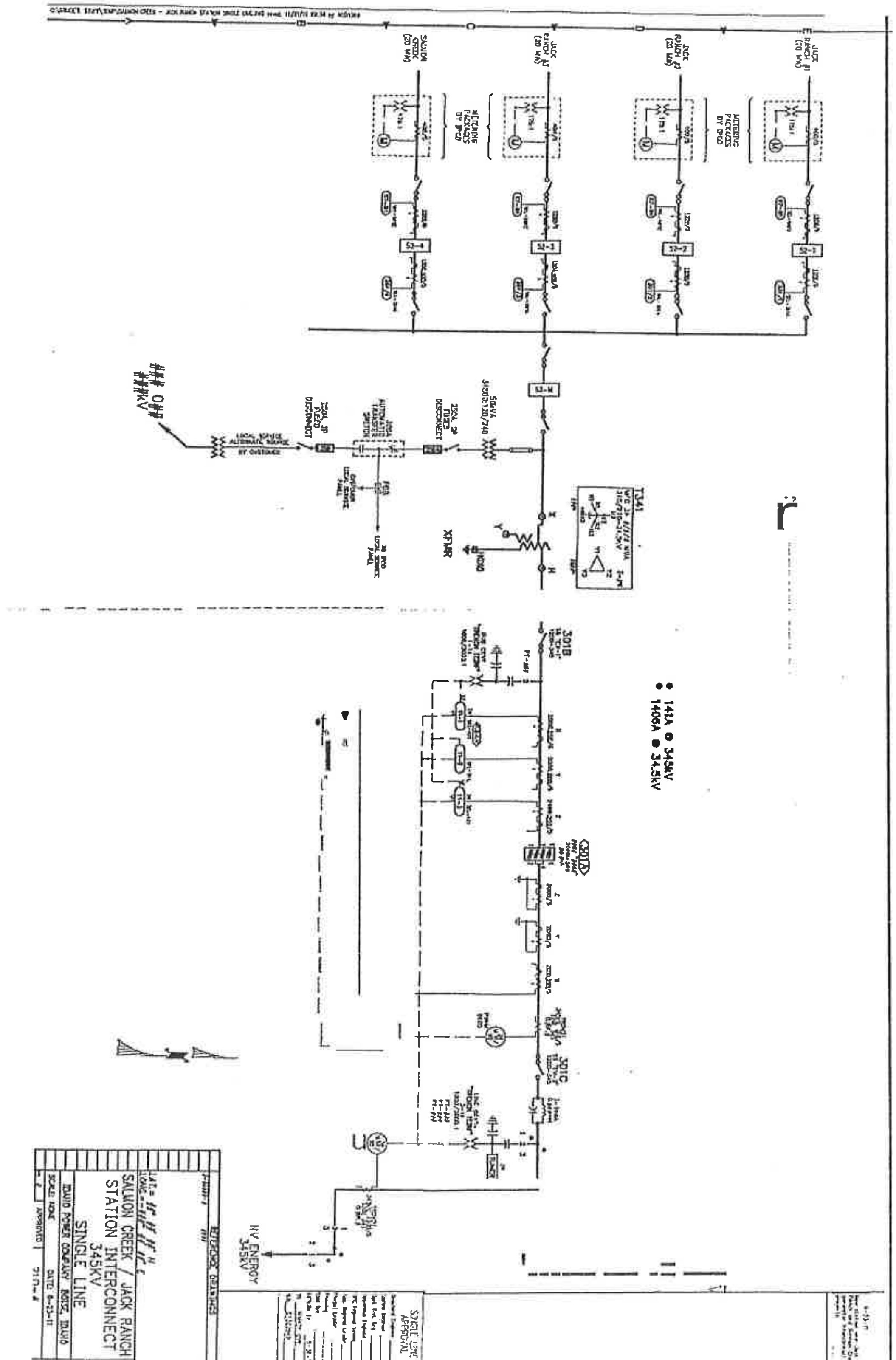
Description	Ownership	Cost Estimate
Interconnection Facilities:		
Interconnection Station	IPC	$2,074,000
345 kV Transmission Line Tap	IPC	$185,000
Jack Ranch Metering (1-3)	IPC	$54,000
Salmon Creek Metering	IPC	$18,000
SUBTOTAL		**$2,331,000**
See Section 6 for Project Grand Total		

Full payment is required up front in accordance with Schedule 72, unless payment arrangements are made in advance with Idaho Power Operations Finance (see Attachment 3).

Billing for construction activities will be based upon actual expenditures.

Attachment 2

One-line Diagram Depicting the Small Generation Facility, Interconnection Facilities, Metering Equipment and Upgrades



Attachment 3

Milestones

1. Idaho Power Company agrees only to the Construction timelines under its direct control provided in the Facility Study Report for this Project.
2. These milestones will begin, and the construction schedule referenced below, will only be valid upon receipt of funding in full from the Seller or their authorized third party no later than the date set forth below for such payment. Additionally, failure by Seller to make the required payments as set forth in this Agreement by the date(s) specified below will be a material breach of this Agreement, which may result in any or all of the following: (i) loss of milestone dates and construction schedules set forth below: (ii) immediate termination of this Agreement by Idaho Power; (iii) removal from the generator interconnection queue.

Critical milestones and responsibility as agreed to by the

Parties: Weeks based from payment date

Date	Responsible Party	Milestones	Week #
6/13/2012	***Seller***	***IPCO receives the balance of Construction estimate $7,847,000.00 OR Credit arrangement are approved by IPCO***	
6/25/2012 – 7/9/2012	***IPCO/ NVE***	***EPC Agreement w/ NV Energy***	2 - 4 weeks
7/2/2012 – 7/16/2012	***IPCO***	***Start of Scoping dependent on resource availability***	3 - 5 weeks
,4/2012 – 10/8/2012	***IPCO***	***IPCO Scope complete - order long lead material (Engineering could bid SOW at this point)***	12-17 weeks
1/28/2013 – 3/22/2013	***IPCO***	***Delivery of Long Lead Material***	33 – 41 weeks
2/11/2013 – 6/10/2013	***IPCO***	***Engineering and Design Complete (Construction could be bid at this point)***	35 - 52 weeks
10/21/2013 – 11/11/2013	***IPCO***	***Construction Complete POI and PLC***	71 - 74 weeks
11/4/2013 – 11/25/2013	***Seller***	***Customer GOLC ready to connect & customer telecomm requirements are complete***	No Later than 2 weeks prior to Commissioning
	NVE	***Construction Complete NVE Protection and PLC***	
11/18/2013 – 12/9/2013	***IPCO***	***POI Commissioning Complete***	75-78
11/18/2013 – 6/9/2014	***IPCO***	***Construction Complete MW Path (permitting dependent)***	75 -104 weeks
	NVE	***Construction Complete MW Path (permitting dependent)***	
	IPCO	***Project Leader issues Construction Complete Letter***	
	Seller	***Customer testing begins***	
	Seller	***Customer's requested In-Service Date***	

NOTE REGARDING MILESTONES:
The above referenced milestone dates are a representative timeframe for construction and sequencing and assumes that required materials can be procured, labor resources are available, and any required outages to the existing system are available to be scheduled. Additionally, any required permitting (such as BLM) and affected party issues (such as NV

Energy's required work) are outside the immediate control of Idaho Power and can influence the identified milestone dates including the Commercial Operation Date.

NV Energy has indicated that it will allow temporary energization of the project prior to the microwave system being in service for a maximum of six months.

* Customer has requested an in-service date of 12/15/2012. Idaho Power does not commit to this date but will use reasonable efforts to have commissioning complete by 6/9/2014. This date is contingent upon all materials being delivered in a timely manner, as well as other factors, some of which are described above. The parties hereby acknowledge that Idaho Power shall not be liable to for any possible damages associated in any way with Renewable Energy Credits or Attributes, tax credits, the firm energy sales agreements, and the like, attributable to Customer, or any of the various projects named on page one of this GIA, should the 6/9/2014 date not be met.

Under normal efforts to bring the projects online a normal amount of overtime is utilized. Because of the Customer's desire to meet an IPC commissioning prior to 6/9/2014, Customer hereby authorizes IPC to incur additional expenses, including additional overtime, lodging, travel, and other expenses needed to bring in other IPC resources and personnel from other IPC regions, or to utilize third party contractors, as necessary to work on this interconnection.

Agreed to by:

For the Seller: Date 13 June 2013

For the Transmission Provider
Idaho Power Company ______________________ Date____________

Attachment 4

Additional Operating Requirements for the Company's Transmission System and Affected Systems Needed to Support the Seller's Needs

The Company shall also provide requirements that must be met by the Seller prior to initiating parallel operation with the Company's Transmission System.

Operating Requirements

The project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-1992 *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems* or any subsequent standards as they may be updated from time to time.

Seller will be able to modify power plant facilities on the generator side of the Interconnection Point with no impact upon the operation of the transmission or distribution system whenever the generation facilities are electrically isolated from the transmission system via the 301B switch and a terminal clearance is issued by Idaho Power Company's Grid Operator.

Generator Output Limit Control ("Re-dispatch" or "GOLC")

The Project will be subject to reductions directed by Idaho Power Company Grid Operations during transmission system contingencies and other reliability events. When these conditions occur, the Project will be subject to Generator Output Limit Control ("GOLC") and have equipment capable of receiving signals from Idaho Power for GOLC. Generator Output Limit Control will be a setpoint from Idaho Power to the Project indicating maximum output allowed. See Attachment 7 for details.

Low Voltage Ride Through

The Project must be capable of riding through faults on adjacent section of the power system without tripping due to low voltage. It has been determined, through study, that the Project must be capable of remaining interconnected for any single phase voltage as low as .125 PU for 9 cycles, and for all three phase voltages as low as .11 PU for 3.7 cycles.

NERC Registry Requirements

The Seller must be registered with NERC as a Generator Owner (GO) and/or Generator Operator (GOP) entity. See NERC registry criteria Section III(c): http://www.nerc.com/files/Statement_Compliance_Registry_Criteria-V5-0.pdf

For further information refer to: NERC Rules of Procedure Section 500 – Organization Registration and Certification; Part 1.3. as they may be updated from time to time: http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20101001.pdf

Meteorlogical Data

Historical wind data – Within 60 days after execution of this Agreement, the Seller shall provide Idaho Power with the following:

a) historical wind data in an electronic format from the proposed Facility site or for a location within two miles of the Facility site.

b) a third party wind assessment study report used by Seller to value investment in the Facility.

No later than 30 days prior to the Commercial Operation Date, the Seller shall have either:

a) Erected at the site at least one (1) high quality, approximate hub-height (plus or minus 20 meters), permanent, meteorological wind measurement tower(s) at location(s) on the site equipped with:

 (i) Two (2) anemometers per tower;

 (ii) Two (2) air temperature sensors per tower;

(iii) One (1) barometric pressure sensor (with DCP sensor); and
(iv) Two (2) wind vanes per tower, or

b) Arranged to provide Idaho Power approximate hub-height wind speed, wind direction, air temperature, barometric pressure, and data from a meteorological wind measurement tower within two miles of the Facility site.

Facility availability status shall be provided as described in the Final Facility Study no later than within the calendar month following the month of the Commercial Operation Date. Failure by the Seller to operate and maintain this equipment to provide such meteorological and turbine availability data in a manner to provide reasonably accurate and dependable data for the full term of this Agreement shall be an event of Default under paragraph 6.5.1.

Attachment 5

Reactive Power Requirements

The Project will support operation in a voltage control mode. The Project must be capable of +/- 0.95 power factor operation, as measured at the Interconnection Point, for all MW production levels from zero MW output to full rated MW output. The Project must have equipment capable of receiving an analog setpoint, via DNP 3.0 from the Idaho Power RTU for voltage setpoint. The setpoint will be the desired voltage level as measured at the interconnect bus. The range of setpoint will be 345.00 kV to 362.25 kV. For more information, please refer to Attachment 7.

Attachment 6

Company's Description of Special Facilities and Upgrades Required to Integrate the Generation Facility and Best Estimate of Costs

As provided in Schedule 72 this Attachment describes Upgrades, Special Facilities, including Network Upgrades, and provides an itemized best estimate of the cost of the required facilities.

Upgrades

Substation Upgrades

Existing WECC criteria require geographic diverse redundant communications paths and redundant or dual primary protection systems. All changes that are made to the line must be designed and maintained in accordance with Idaho Power standards and the WECC standards.

Idaho Power

- Midpoint – Protective relays will be replaced with IPCo standard SEL421/311L line relay panel. Primary breaker failure will be provided by a second SEL 421 relay.
- Midpoint - Upgrade of the L346 neutral grounding reactor for the line (currently at 32kVA and assumed at 500 kVAr)*
- Midpoint - Replace the existing Wave Trap to match the rating of the line.
- Midpoint – New 3 phase PLC

NV Energy

- Humboldt - Relaying upgrades will also be required at the NV Energy terminal. They will consist of an SEL-421 and SEL-311L relay for primary protection. Additional relaying to perform breaker failure, back-up protective functions, and control tasks may be required by NV Energy and may not match the relaying specified by Idaho Power for the Midpoint terminal.
- Humboldt – New 3 phase PLC
- CMMW – Microwave addition to IPCo facility
- Ellen Dee – New Microwave site

The following good faith estimates are provided in 2011 dollars:

Description	Ownership	Cost Estimate
Interconnection Facilities:		
Interconnection Station	IPC	$2,074,000
345 kV Transmission Line Tap	IPC	$185,000
Jack Ranch Metering	IPC	$54,000
Salmon Creek Metering	IPC	$18,000
SUBTOTAL		**$2,331,000**
Substation Upgrades:		
Midpoint Protection	IPC	$200,000
Midpoint Neutral Grounding Reactor	IPC	$126,000
Midpoint PLC/ wave trap	IPC	$473,000
Jack Ranch / Salmon Creek Communications	IPC	$767,000
Jack Ranch / Salmon Creek PLC	IPC	$526,000
CMMW Communications	IPC	$1,375,000

Lower Salmon Communications	IPC	$387,000
Humboldt Protection	NVE	$351,000
Humboldt PLC	NVE	$286,000
CMMW Communications	NVE	$125,000
Ellen Dee Communications	NVE	$900,000
SUB TOTAL		**$5,516,000**
GRAND TOTAL		**$7,847,000**

Attachment 7
Generation Interconnection Control Requirements

Generator Output Limit Control (GOLC)
IPCO requires Interconnected Power Producers to accept GOLC signals from our EMS.

The GOLC signals will consist of two points shared between the IPCO EMS and the Customer's Generator Controller:

GOLC Setpoint: An analog output that contains the MW value the Customer should curtail to, should a GOLC request be made via the GOLC On/Off discrete output Control point.
An Analog Input feedback point must be updated (to reflect the GOLC setpoint value) by the Customer Controller upon the Controller's receipt of the GOLC setpoint change, with no intentional delay.

GOLC On/Off: A discrete output (DO) control point with latching Off/On states. Following a "GOLC On" control, the Customer Controller will run power output back to the MW value specified in the GOLC Setpoint. Following a "GOLC Off" control, the Customer is free to run to maximum possible output.
A Discrete Input feedback point must be updated (to reflect the GOLC DO state) by the Customer Controller upon the Controller's receipt of the GOLC DO state change, with no intentional delay.

If a GOLC control is issued, it is expected to see MW reductions start within 1 minute and plant output to be below the GOLC Setpoint value within 10 minutes.

Voltage Control
Idaho Power Company requires Transmission-Interconnected Power Producers to accept Voltage Control signals from our EMS when they are connected to our transmission system.

The voltage control will consist of one setpoint shared between the IPCO EMS and the Customer Controller.

The setpoint will contain the desired target voltage for the plant to operate at.

The control will always be active, there is no digital supervisory point like the Curtail On/Off control above.
When a setpoint change is issued an Analog Input feedback point must be updated (to reflect the Voltage Control setpoint value) by the Customer Controller upon the Controller's receipt of the Voltage Control setpoint change, with no intentional delay.
When a setpoint change is received by the Customer Controller, the Voltage Control system should react with no intentional delay.
The voltage control system should operate in a dead band of +/-5% of the control setting range.

The customer should supervise this control by setting up "reasonability limits", i.e. configure a reasonable range of values for this control to be valid. As an example, they will accept anything between .95 and 1.05 for the set point. In the case they are fed an erroneous value outside this range, their control system defaults to the last known, good value.

Generation Interconnection Data Points Requirements

Digital Inputs to IPCo (DNP Obj. 01, Var. 2)			
Index	Description	State (0/1)	Comments:
0	52A Customer Capacitor Breaker (if present)	Open/Closed	Sourced at substation
1	GOLC Off/On Control Received (Feedback)	Off/On	Provided by Customer

Digital Outputs to Customer (DNP Obj. 10, Var. 1)		
Index	Description	Comments:
0	GOLC Off/On	Provided by IPCO
	NOTE: GOLC Setpoint indicates MW value to curtail to when GOLC Off/On DO is ON.	

Analog Inputs to IPCo (DNP Obj. 30, Var. 2)							
Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
0	GOLC Setpoint Value Received (Feedback)	32767	-32768	TBD	TBD	MW	Provided by Seller
1	Voltage Control Setpoint Value Rec'd (Feedback)	32767	-32768	TBD	TBD	kV	Provided by Seller
2	Maximum Park Generating Capacity	32767	-32768	TBD	TBD	MW	Provided by Seller
3	Number of Turbines In High Speed Cutout	32767	-32768	32767	-32768	Units	Provided by Seller
4	Ambient Temperature	32767	-32768	327.67	-327.68	F or C	Provided by Seller
5	Wind Direction	32767	-32768	3276.7	-3276.8	Deg	Provided by Seller
6	Wind Speed	32767	-32768	327.67	-327.68	MPH or m/s	Provided by Seller

Analog Outputs to Customer (DNP Obj. 40, Var. 2)							
Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
0	GOLC Setpoint	32767	-32768	TBD	TBD	MW	Provided by IPCO
1	Voltage Control Setpoint	32767	-32768	TBD	TBD	kV	Provided by IPCO
	NOTE: Curtailment Setpoint indicates MW value to Curtail to when Curtailment Off/On DO is ON.						

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 57

McGuireWoods LLP
600 Travis Street
Suite 7500
Houston, TX 77002-2906
Phone: 713.571.9191
Fax: 713.571.9652
www.mcguirewoods.com

Peter A. del Vecchio
Direct: 713.353.6672

MCGUIREWOODS

pdelvecchio@mcguirewoods.com
Direct Fax: 832.214.9929

June 13, 2012

Donovan Walker
Legal Department
Idaho Power Company
1221 West Idaho Street
Boise, ID 83702

RE: Exergy Development Group of Idaho, LLC's Jack Ranch Projects

Dear Donovan:

I am writing on behalf of Exergy Development Group of Idaho, LLC, in response to your letter to Mr. James Carkulis dated June 12, 2012. That letter rejected Exergy's ongoing attempts to seek from Idaho Power reasonable use of fair and well-established interconnection procedures that Exergy believes would allow it to interconnect its projects in a timely manner. Idaho Power's position has placed Exergy in a very difficult position, and may compel Exergy to pursue all available legal and equitable remedies for what amounts to a breach of good faith and fair dealing under Idaho contract law, as well as discriminatory treatment under implementing rules of the Public Utilities Regulatory Policy Act of 1978.

As you know, Exergy is the developer of four qualifying facility (QF) projects referred to as the Deep Creek, Rogerson Flats, Cottonwood, and Salmon Creek projects (the "Projects"). Exergy executed firm energy sales agreements (FESAs) with Idaho Power for each of these Projects in late 2010. Idaho Power required the inclusion in these FESAs of a delay liquidated damages provision that required Exergy to post $45/kilowatt of nameplate capacity to ensure that the Projects would meet a Scheduled Operation Date of June 30, 2012. Idaho Power included in the delay default provision the requirement in Article 4.1.7 that Exergy be able to "Provide written confirmation from Idaho Power's delivery business unit that Seller has satisfied all interconnection requirements." Idaho Power drafted those provisions and – other than the projected date itself – provided Exergy with no opportunity for input.

As Exergy has communicated to Idaho Power, Exergy believed it would be able to achieve the interconnection component by the Scheduled Operation Date by interconnecting these four Projects at the point of interconnection on the 345 kV line used in Interconnection Request No. 327. From the well-advanced interconnection process initiated under Idaho Power Open Access Transmission Tariff (OATT) for Interconnection No. 327, Exergy expected that there would be no issue with completing the interconnection of the lesser 80-MW output by the required date. Your accusations that the Projects had been moved forward by Exergy with a blind eye to interconnection risk is simply wrong. The interconnect feasibility study for this interconnect request was completed by Idaho Power on July 28, 2010. That study, which was completed six months PRIOR to execution of the Jack Ranch FESAs, provides: "The proposed in-service date is December 2011." The Projects, in reliance on Idaho Power's own study, then requested an on line date in July 2012, on the assumption that the interconnection work to be performed by Idaho Power would take no more than a year. This assumption was collaborated by the System Impact Study which was completed in December of 2010. That study also states that: "The proposed in-service date for this Project is December 2011." Exergy reasonably and in good faith relied upon Idaho Power to make an informed decision as to the appropriate on line date.

Idaho Power worked with Exergy under the terms of the OATT to make modifications to the initial 200MW Energy Resource designation for Interconnection Request No. 327 to allow for these four QF Projects to interconnect at the same location on the applicable 345 kV line. Exergy consequently understood Idaho Power to be proceeding under the terms of the OATT for this interconnection. Exergy considers the terms of the OATT to allow for a quicker progression to a fully completed interconnection process. Exergy maintains that, had Idaho Power consistently adhered to the principles of the OATT, it could have progressed much more quickly to a reasonable and fully executed Large Generator Interconnection Agreement. But Idaho Power has failed to do so.

For example, the OATT section 32.1 requires that if the Transmission Provider determines that a system impact study is necessary, it shall so inform the transmission customer "as soon as practicable," but in any event will provide a system impact study agreement within 30 days of a completed application for network resource designation. Exergy's letter initiating the revised network transmission request from the revised point of interconnection was sent June 3, 2011, and it took 75 days for Idaho Power to respond on August 17, 2011 that a system impact study would be needed. For a much more complicated process of actually completing a system impact study or a facility study, the OATT only allows only 60 days, and under sections 19.9 and 32.5 requires Idaho Power to file a notice and possibly incur penalties with FERC if a significant number of studies for non-affiliates exceed that 60-day deadline. Additionally, Idaho Power's August 17, 2011 letter provided Exergy with six days to execute the included network transmission study agreement regarding the system impact study and deposit $10,000, but Idaho Power's OATT section 32.1 provides a transmission customer with 15 days to execute a system impact study agreement.

The 75-day response period for Idaho Power (compared to 30 days in the OATT) and the 6-day response requirement for Exergy (compared to 15 days in the OATT) are flatly discriminatory to Exergy's QF Projects as compared to others who are attempting to use the transmission system. This is only one such example of Idaho Power's delays and unreasonable requirements placed upon Exergy with regard to the interconnection and network transmission components of these Projects.

In fact, Idaho Power has unilaterally imposed short response times for Exergy and allowed itself generous amounts of time achieve various tasks throughout this process. To put it simply, Exergy has made clear its intent to proceed under the reasonable timelines set forth in the OATT in order to avoid being in default of Idaho Power's unreasonable delay damages provision in the FESAs. Yet Idaho Power has refused to follow that process, and instead has materially frustrated Exergy's ability to complete the interconnection.

Your letter sent June 12, 2012 is yet another example. Idaho Power Transmission apparently believes it is not capable of having the interconnection complete in time for the deadline in the FESAs, or the 90 days thereafter Idaho Power has provided for Exergy to cure any delay "default" prior to Idaho Power's right (again, under the FESAs it drafted) to terminate the FESAs. Exergy reasonably proposed to use a common procedure from Section 5.1.3 of Idaho Power's OATT to self build the interconnection. That would at least place Exergy in control of the interconnection construction, and consequently the related ability to achieve online status accordance with the FESAs. There is no basis for denial of this request. Exergy and its partners clearly have the capacity to self construct the interconnection process.

Your reliance on the terms and provisions of a state-jurisdictional Schedule 72 are unavailing. First, Idaho Power has consented to use the procedures of the OATT by course of conduct. Those provisions were used in correspondence between Exergy and Idaho Power to make the necessary modifications to the Interconnection Request No. 327 beginning in April 2011. You claim that Exergy failed to adhere to some "comment period" that Idaho Power has created. However, even if Idaho Power could foist an unfair process on an interconnecting generator for some failure to provide comments, we understand that Exergy has communicated its intent to use the OATT provisions consistently from the start. Idaho Power cannot indiscriminately "cherry pick", using some provisions of the OATT favorable to itself at some points and completely ignoring OATT at other times whenever Idaho Power chooses.

Second, and more importantly, the Schedule 72 process as applied is inconsistent with federal and state QF regulations. Idaho Power is discriminating against and providing less protection to the interconnection rights of QFs than those available for non-QF generators. As you are well aware, "a state may only take action under PURPA to the extent that that action is consistent with [FERC's] rules." *Cedar Creek Wind, LLC*, 137 FERC 61,006, ¶ 27 (2011). Federal Energy Regulatory Commission (FERC) regulations and case precedent is abundantly clear that well-established interconnection protections afforded under PURPA are intended to prevent the type of discriminatory treatment exhibited by Idaho Power here (e.g. 18 C.F.R. § 292.301 - 314). By prohibiting Exergy from self-building its QFs' interconnection in the same manner Idaho Power is required to allow non-QF generators under the OATT, Idaho Power is using the Schedule 72 process as an unreasonable shield to discriminate against Exergy, subverting and contorting the very purpose of Schedule 72.

Finally, a duty of good faith and fair dealing is implied in any contract. *Indep. Sch. Dist. of Boise City v. Harris Family Ltd. P'ship*, 150 Idaho 583, 589, 249 P.3d 382, 388 (2011). The four FESAs at issue here are no exception. Idaho Power has unreasonably demanded that, in order for Exergy to exercise its state and federal right to sell to Idaho Power as a QF, Exergy must agree to a delay default damages provision that required Exergy to post substantial security in excess of three million dollars for these Projects. Idaho Power claims in other forums that it does not need the output from wind projects at this time. Yet here Idaho Power refuses to slightly extend the online date in Exergy's FESAs. For Idaho Power to insist upon building the interconnection itself under deadlines that will not meet the deadlines Idaho Power refuses to move in the FESA is a transparent attempt to terminate the FESAs. Idaho Power cannot pretend as though it is two different entities. Idaho Power's intent is clear. No court would view Idaho Power's conduct as anything other than a monopolist utility's attempt to terminate the FESAs. As such, Idaho Power's actions are a clear breach of the implied covenant of good faith and fair dealing.

Idaho Power's entire course of conduct including its actions, inactions and interactions with Exergy regarding the interconnection procedures with respect to its four QF Projects and the related FESAs has the potential to cause tremendous harm to Exergy and seriously threatens the viability of these Projects. Earlier today, Exergy had delivered to Idaho Power executed counterparts of the relevant Interconnection Agreements. We are expecting Idaho Power to execute and deliver counterparts of Interconnection Agreement to Exergy as soon as possible. If this is not completed by the close of business on Monday, June 18th or if Idaho Power formally or informally removes any of the Projects from its interconnection queue, Exergy intends to pursue all available legal and equitable remedies against Idaho Power for all direct and indirect costs associated with these Projects, including the return of all security payments made under the FESAs, all hard and soft development and construction costs associated with the Projects, the value of all non-refundable deposits placed on wind turbines and other equipment, as well as other consequential and punitive damages.

Sincerely,

P del Vecchio

Peter A. del Vecchio

cc. James Carkulis, Exergy Development Group of Idaho, LLC
Peter Richardson, Richardson & O'Leary

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 58

June 14, 2012
VIA email & Certified Mail # 70113500000156449112

James Carkulis
Exergy Development Group
802 West Bannock Street, 12th Floor
Boise, Idaho 83702

Subject: Jack Ranch Projects Project # 325/327 – FINAL NOTICE

Dear James Carkulis:

By letter dated May 14, 2012, Idaho Power Company ("Idaho Power") provided the Exergy Development Group ("Exergy") with a Final Generator Interconnection Agreement ("Final GIA") for the proposed Jack Ranch Projects ("Projects") to be interconnected in Twin Falls County, Idaho. Exergy was to execute and return the Final GIA with the required deposit by June 13, 2012. That time period has now expired. Exergy did not provide Idaho Power an executed copy of the Final GIA, nor was a deposit for the Projects received. Therefore, the Projects have been removed from Idaho Power's generator interconnection queue.

Should you wish to continue to pursue generator interconnection for the Projects, you may re-submit an application that can be found on www.idahopower.com.

Sincerely,

Tess Park

Tess Park
Load Serving Operations Director
Ph 208.388.2360

cc (via email):
Donovan Walker/IPC
Nancy Cyr/IPC
Aubrae Sloan/IPC
Josh Harris/IPC

P.O. Box 70 (83707)
1221 W. Idaho St.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 59

RICHARDSON & O'LEARY, PLLC
ATTORNEYS AT LAW

Peter Richardson

Tel: 208-938-7901 Fax: 208-938-7904
peter@richardsonandoleary.com
P.O. Box 7218 Boise, ID 83707 - 515 N. 27th St. Boise, ID 83702

RECEIVED
JUN 18 2012
By CB

June 15, 2012

Tess Park, Load Serving Operations Director
Idaho Power Company
1221 West Idaho Street
Boise, Idaho 83702
HAND DELIVERY

Re: Jack Ranch Projects, Project No. 325/327

Dear Ms. Park:

I am in receipt of your letter dated June 14, 2012 addressed to Mr. Carkulis. You must have realized by now that your statement that "Exergy did not provide Idaho Power an executed copy of the Final GIA, nor was a deposit for the Projects received" is in error. An Exergy employee delivered a signed GIA directly and personally to Mr. Donovan Walker at five minutes of five p.m. on Wednesday the 13th. That GIA was, in fact executed by Mr. Carkulis and Mr. Carkulis is prepared to post the deposit when the agreement is fully executed by Idaho Power.

I therefore respectfully request that you replace these projects to their rightful place in the queue.

Sincerely yours,

Peter Richardson

Cc: Donovan Walker, Senior Attorney – Idaho Power Company

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 60

IDAHO POWER®
An IDACORP Company

DONOVAN E. WALKER
Lead Counsel
dwalker@idahopower.com

June 18, 2012

VIA ELECTRONIC & U.S. MAIL

Peter J. Richardson
RICHARDSON & O'LEARY, PLLC
515 North 27th Street
P.O. Box 7218
Boise, Idaho 83702

Re: Jack Ranch Projects – Your June 15, 2012, letter to Tess Park

Dear Mr. Richardson:

This letter responds to your letter of June 15, 2012, to Idaho Power's Tess Park. In that letter you represent that Mr. Carkulis did, "in fact" sign the Final GIA for the Jack Ranch Projects. This is factually incorrect. Mr. Carkulis delivered to Idaho Power, at 4:57 p.m. on Wednesday, June 13, 2012, versions of the Final GIA that had been modified, and then signed by Mr. Carkulis. The modification(s) to the document were not red-lined or otherwise identified in the document. In fact, the modification(s) were not even pointed out until the two representatives of Exergy that made the delivery were asked directly if there were any changes made to the documents. At that time the Exergy representatives pointed out some additional language that was added to the pro-forma portion of the Final GIA, in Section 8, where a subsection 8.3 was added to include language allowing Exergy to self build all required interconnection facilities and upgrades.

As you are well aware, this particular issue was expressly addressed in my June 12, 2012, letter to Mr. Carkulis, and was expressly discussed on the phone conference that you organized on June 13, 2012, attended by myself and Jason Williams for Idaho Power, as well as you and your associate, Greg Adams, several attorneys from McGuire Woods from across the country, and the two representatives of Exergy that hand delivered the modified documents directly after the call. The unambiguous communication from both the June 12, 2012, letter as well as the June 13 conference call is that the requested self-build language is not an appropriate, nor an acceptable term in the Final GIA. Contrary to these communications, Mr. Carkulis unilaterally inserted the inappropriate language into the Final GIA before signing and returning the same to Idaho Power. Consequently, Mr. Carkulis failed to sign and return the Final GIA that was sent to Exergy on May 14, 2012, by the June 13, 2012, deadline. Additionally, Mr. Carkulis did not pay the required deposit by the close of business on June 13, 2012.

As previously communicated to Exergy by letter dated June 14, 2012, because Exergy did not return an executed copy of the Final GIA, nor pay the required deposit funds by the June 13, 2012, deadline, the Projects have been removed from Idaho Power's generator interconnection queue.

Sincerely,

Donovan E. Walker

DEW:csb
cc: Lisa Grow, Idaho Power (via e-mail)
Tess Park, Idaho Power (via e-mail)
Randy Allphin, Idaho Power (via e-mail)
Jason Williams, Idaho Power Corporate Counsel (via e-mail)
James Carkulis, Exergy (via e-mail)

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 61

exergy DEVELOPMENT GROUP

NOTICE OF FORCE MAJEURE
UNDER
FIRM ENERGY SALE AGREEMENTS DATED DECEMBER 10, 2010
RE: JACK RANCH PROJECTS:

DEEP CREEK (# 31721200)
ROGERSON FLATS (#31721300)
SALMON CREEK (#31721400)
COTTONWOOD (#31721100)

From Seller: Exergy Development Group of Idaho, LLC
802 W. Bannock Ste. 1200
Boise, ID 83702
Attn: James Carkulis, Managing Member
Email: jcarkulis@exergydevelopment.com

To Idaho Power: Vice President, Power Supply.
Idaho Power Company
PO Box 70
Boise, Idaho 83707
Email: lgrow@idahopower.com

With copy to: Cogeneration and Small Power Production
Idaho Power Company
PO Box 70
Boise, Idaho 83707
Email: rallphin@idahopower.com

Date: June 28, 2012

VIA EMAIL AND REGULAR MAIL

In accordance with Article XIV (Force Majeure) of the Firm Energy Sale Agreements referenced above (hereinafter, collectively, the "FESA"), Seller hereby gives Idaho Power written notice of the occurrence of Force Majeure events, in the following particulars:

1. Pursuant to studies, Idaho Power established interconnection facilities and upgrade construction completion dates as occurring in December 2011. Idaho Power communicated same to Seller, and Seller, in reliance, and in discussions with Idaho Power, established June 20, 2012, as the Scheduled Operation Date under the FESA.

exergy
DEVELOPMENT GROUP

2. Unilaterally, Idaho Power then decided to conduct further studies and based thereon, unilaterally moved its interconnection facilities and upgrade construction completion dates forward, most recently settling on dates in June 2014.

3. Despite repeated requests from Seller, Idaho Power has refused to amend the FESA to allow Seller to change its Scheduled Operation Date to reasonably accommodate Idaho Power's change of its interconnection facilities and upgrade construction completion dates to June 2014.

4. Because Idaho Power has arbitrarily moved its interconnection facilities and upgrade construction completion dates to a date that is after Seller's Scheduled Operation Date, Idaho Power has unilaterally created the absolute impossibility of performance on the part of Seller. This intentional and intended consequence has been repeatedly brought to the attention of Idaho Power and is well known to Idaho Power.

5. The intentional and intended consequences of Idaho Power's unilateral manipulation of dates within its sole control, serves to have created, by Idaho Power's own actions, the cause of the looming, certain and impossible achievement by Seller of the Scheduled Operation Date of June 30, 2012. Idaho Power's refusal to agree to a reasonable change in the Scheduled Operation Date is clearly "beyond the control of the Seller...despite the exercise of due diligence...[that Seller] is unable to prevent or overcome..." and is, therefore within the definition of Force Majeure as set forth in Article XIV the FESA.

6. This is not a case of Seller failing to post delay security (such has been posted). This is not a case of Seller's reliance upon the actions of third party permitting agencies (such as, by way of example, and not limitation, the BLM). This is not a case where there are events or issues arising outside of the control of Idaho Power. To the contrary, this is a case where there has been, and continues to be, unilateral and intentional delay and manipulation by Idaho Power of events and issues solely with the control of Idaho Power, the intent of which is to cause the default to Seller. For example, Idaho Power could easily agree to amend the FESA to a reasonable date that correlates to the revised Idaho Power dates (changed after Seller has relied upon originally established dates). Idaho Power refuses to do so.

7. Further, Idaho Power has also set the stage for impossibility of performance on the part of Seller with respect to the condition imposed by Section 4.1.7 (Interconnection) of the FESA, that Seller provide written confirmation by Idaho Power to Idaho Power of the satisfaction of all interconnection requirements. Pursuant to the chain of letter correspondence attached (notwithstanding that there are fundamental disagreements between Seller and Idaho Power regarding the matters set forth therein), Idaho Power has chosen not to countersign the GIA signed and submitted to Idaho Power, thereby making satisfaction of this condition impossible. Seller reserves all rights to contest the position of Idaho Power regarding the GIA as set forth in the attached correspondence (in particular the incorrect recollection of Donovan Walker regarding the circumstances of how the insertion of the Section 8.3 Option to Build per OATT was brought to his attention). However, for purposes of describing with particularity the occurrence of an event of Force Majeure, the attached is submitted as such description, and as forming the basis for Seller's

DEVELOPMENT GROUP

notice to Idaho Power that Idaho Power's unilateral refusal to sign a contract creates an event beyond the control of Seller within the definition of Force Majeure as set forth in the FESA.

Accordingly, by this written notice to Idaho Power, Idaho Power is advised that its actions have created a Force Majeure event, thereby creating a suspension of performance for the duration of the event, as further described in Article XIV of the FESA.

Further, pursuant to Section 19.1 (Disputes) of Article XIX of the FESA, if Idaho Power disputes this matter, Seller reserves the right to submit the same to the Idaho Public Utilities Commission and/or pursue any resolution to which it may be entitled before the appropriate Idaho district court, FERC and/or any other applicable tribunal or governing body.

Further, Seller asserts that it is protected from any default under the FESA pending resolution of the asserted Force Majeure issues, including, without limitation, any dispute or litigation as to whether said Force Majeure Event does protect Seller from any such default.

SELLER:

Exergy Development Group of Idaho, LLC

By: ______________________
James T. Carkulis
Managing Member

cc (via email): Donovan E. Walker
Peter J. Richardson
Peter A. del Vecchio
Richard A. Riley
Brian L. Ballard

IDAHO POWER®
An IDACORP Company

DONOVAN E. WALKER
Lead Counsel
dwalker@idahopower.com

June 18, 2012

VIA ELECTRONIC & U.S. MAIL

Peter J. Richardson
RICHARDSON & O'LEARY, PLLC
515 North 27th Street
P.O. Box 7218
Boise, Idaho 83702

Re: Jack Ranch Projects – Your June 15, 2012, letter to Tess Park

Dear Mr. Richardson:

This letter responds to your letter of June 15, 2012, to Idaho Power's Tess Park. In that letter you represent that Mr. Carkulis did, "in fact" sign the Final GIA for the Jack Ranch Projects. This is factually incorrect. Mr. Carkulis delivered to Idaho Power, at 4:57 p.m. on Wednesday, June 13, 2012, versions of the Final GIA that had been modified, and then signed by Mr. Carkulis. The modification(s) to the document were not red-lined or otherwise identified in the document. In fact, the modification(s) were not even pointed out until the two representatives of Exergy that made the delivery were asked directly if there were any changes made to the documents. At that time the Exergy representatives pointed out some additional language that was added to the pro-forma portion of the Final GIA, in Section 8, where a subsection 8.3 was added to include language allowing Exergy to self build all required interconnection facilities and upgrades.

As you are well aware, this particular issue was expressly addressed in my June 12, 2012, letter to Mr. Carkulis, and was expressly discussed on the phone conference that you organized on June 13, 2012, attended by myself and Jason Williams for Idaho Power, as well as you and your associate, Greg Adams, several attorneys from McGuire Woods from across the country, and the two representatives of Exergy that hand delivered the modified documents directly after the call. The unambiguous communication from both the June 12, 2012, letter as well as the June 13 conference call is that the requested self-build language is not an appropriate, nor an acceptable term in the Final GIA. Contrary to these communications, Mr. Carkulis unilaterally inserted the inappropriate language into the Final GIA before signing and returning the same to Idaho Power. Consequently, Mr. Carkulis failed to sign and return the Final GIA that was sent to Exergy on May 14, 2012, by the June 13, 2012, deadline. Additionally, Mr. Carkulis did not pay the required deposit by the close of business on June 13, 2012.

As previously communicated to Exergy by letter dated June 14, 2012, because Exergy did not return an executed copy of the Final GIA, nor pay the required deposit funds by the June 13, 2012, deadline, the Projects have been removed from Idaho Power's generator interconnection queue.

Sincerely,

Donovan E. Walker

DEW:csb
cc: Lisa Grow, Idaho Power (via e-mail)
Tess Park, Idaho Power (via e-mail)
Randy Allphin, Idaho Power (via e-mail)
Jason Williams, Idaho Power Corporate Counsel (via e-mail)
James Carkulis, Exergy (via e-mail)

RICHARDSON & O'LEARY, PLLC
ATTORNEYS AT LAW

Peter Richardson

Tel: 208-938-7901 Fax: 208-938-7904
peter@richardsonandoleary.com
P.O. Box 7218 Boise, ID 83707 - 515 N. 27th St. Boise, ID 83702

June 15, 2012

Tess Park, Load Serving Operations Director
Idaho Power Company
1221 West Idaho Street
Boise, Idaho 83702
HAND DELIVERY

Re: Jack Ranch Projects, Project No. 325/327

Dear Ms. Park:

I am in receipt of your letter dated June 14, 2012 addressed to Mr. Carkulis. You must have realized by now that your statement that "Exergy did not provide Idaho Power an executed copy of the Final GIA, nor was a deposit for the Projects received" is in error. An Exergy employee delivered a signed GIA directly and personally to Mr. Donovan Walker at five minutes of five p.m. on Wednesday the 13th. That GIA was, in fact executed by Mr. Carkulis and Mr. Carkulis is prepared to post the deposit when the agreement is fully executed by Idaho Power.

I therefore respectfully request that you replace these projects to their rightful place in the queue.

Sincerely yours;

Peter Richardson

Cc: Donovan Walker, Senior Attorney – Idaho Power Company

IDAHO POWER®
An IDACORP Company

June 14, 2012
VIA email & Certified Mail # 70113500000156449112

James Carkulis
Exergy Development Group
802 West Bannock Street, 12th Floor
Boise, Idaho 83702

Subject: Jack Ranch Projects Project # 325/327 – FINAL NOTICE

Dear James Carkulis:

By letter dated May 14, 2012, Idaho Power Company ("Idaho Power") provided the Exergy Development Group ("Exergy") with a Final Generator Interconnection Agreement ("Final GIA") for the proposed Jack Ranch Projects ("Projects") to be interconnected in Twin Falls County, Idaho. Exergy was to execute and return the Final GIA with the required deposit by June 13, 2012. That time period has now expired. Exergy did not provide Idaho Power an executed copy of the Final GIA, nor was a deposit for the Projects received. Therefore, the Projects have been removed from Idaho Power's generator interconnection queue.

Should you wish to continue to pursue generator interconnection for the Projects, you may re-submit an application that can be found on www.idahopower.com.

Sincerely,

Tess Park

Tess Park
Load Serving Operations Director
Ph 208.388.2360

cc (via email):
Donovan Walker/IPC
Nancy Cyr/IPC
Aubrae Sloan/IPC
Josh Harris/IPC

McGuireWoods LLP
600 Travis Street
Suite 7500
Houston, TX 77002-2906
Phone: 713.571.9191
Fax: 713.571.9652
www.mcguirewoods.com

Peter A. del Vecchio
Direct: 713.353.6672

McGUIREWOODS

pdelvecchio@mcguirewoods.com
Direct Fax: 832.214.9929

June 13, 2012

Donovan Walker
Legal Department
Idaho Power Company
1221 West Idaho Street
Boise, ID 83702

RE: Exergy Development Group of Idaho, LLC's Jack Ranch Projects

Dear Donovan:

I am writing on behalf of Exergy Development Group of Idaho, LLC, in response to your letter to Mr. James Carkulis dated June 12, 2012. That letter rejected Exergy's ongoing attempts to seek from Idaho Power reasonable use of fair and well-established interconnection procedures that Exergy believes would allow it to interconnect its projects in a timely manner. Idaho Power's position has placed Exergy in a very difficult position, and may compel Exergy to pursue all available legal and equitable remedies for what amounts to a breach of good faith and fair dealing under Idaho contract law, as well as discriminatory treatment under implementing rules of the Public Utilities Regulatory Policy Act of 1978.

As you know, Exergy is the developer of four qualifying facility (QF) projects referred to as the Deep Creek, Rogerson Flats, Cottonwood, and Salmon Creek projects (the "Projects"). Exergy executed firm energy sales agreements (FESAs) with Idaho Power for each of these Projects in late 2010. Idaho Power required the inclusion in these FESAs of a delay liquidated damages provision that required Exergy to post $45/kilowatt of nameplate capacity to ensure that the Projects would meet a Scheduled Operation Date of June 30, 2012. Idaho Power included in the delay default provision the requirement in Article 4.1.7 that Exergy be able to "Provide written confirmation from Idaho Power's delivery business unit that Seller has satisfied all interconnection requirements." Idaho Power drafted those provisions and – other than the projected date itself – provided Exergy with no opportunity for input.

As Exergy has communicated to Idaho Power, Exergy believed it would be able to achieve the interconnection component by the Scheduled Operation Date by interconnecting these four Projects at the point of interconnection on the 345 kV line used in Interconnection Request No. 327. From the well-advanced interconnection process initiated under Idaho Power Open Access Transmission Tariff (OATT) for Interconnection No. 327, Exergy expected that there would be no issue with completing the interconnection of the lesser 80-MW output by the required date. Your accusations that the Projects had been moved forward by Exergy with a blind eye to interconnection risk is simply wrong. The interconnect feasibility study for this interconnect request was completed by Idaho Power on July 28, 2010. That study, which was completed six months PRIOR to execution of the Jack Ranch FESAs, provides: "The proposed in-service date is December 2011." The Projects, in reliance on Idaho Power's own study, then requested an on line date in July 2012, on the assumption that the interconnection work to be performed by Idaho Power would take no more than a year. This assumption was collaborated by the System Impact Study which was completed in December of 2010. That study also states that: "The proposed in-service date for this Project is December 2011." Exergy reasonably and in good faith relied upon Idaho Power to make an informed decision as to the appropriate on line date.

Idaho Power worked with Exergy under the terms of the OATT to make modifications to the initial 200MW Energy Resource designation for Interconnection Request No. 327 to allow for these four QF Projects to interconnect at the same location on the applicable 345 kV line. Exergy consequently understood Idaho Power to be proceeding under the terms of the OATT for this interconnection. Exergy considers the terms of the OATT to allow for a quicker progression to a fully completed interconnection process. Exergy maintains that, had Idaho Power consistently adhered to the principles of the OATT, it could have progressed much more quickly to a reasonable and fully executed Large Generator Interconnection Agreement. But Idaho Power has failed to do so.

For example, the OATT section 32.1 requires that if the Transmission Provider determines that a system impact study is necessary, it shall so inform the transmission customer "as soon as practicable," but in any event will provide a system impact study agreement within 30 days of a completed application for network resource designation. Exergy's letter initiating the revised network transmission request from the revised point of interconnection was sent June 3, 2011, and it took 75 days for Idaho Power to respond on August 17, 2011 that a system impact study would be needed. For a much more complicated process of actually completing a system impact study or a facility study, the OATT only allows only 60 days, and under sections 19.9 and 32.5 requires Idaho Power to file a notice and possibly incur penalties with FERC if a significant number of studies for non-affiliates exceed that 60-day deadline. Additionally, Idaho Power's August 17, 2011 letter provided Exergy with six days to execute the included network transmission study agreement regarding the system impact study and deposit $10,000, but Idaho Power's OATT section 32.1 provides a transmission customer with 15 days to execute a system impact study agreement.

The 75-day response period for Idaho Power (compared to 30 days in the OATT) and the 6-day response requirement for Exergy (compared to 15 days in the OATT) are flatly discriminatory to Exergy's QF Projects as compared to others who are attempting to use the transmission system. This is only one such example of Idaho Power's delays and unreasonable requirements placed upon Exergy with regard to the interconnection and network transmission components of these Projects.

In fact, Idaho Power has unilaterally imposed short response times for Exergy and allowed itself generous amounts of time achieve various tasks throughout this process. To put it simply, Exergy has made clear its intent to proceed under the reasonable timelines set forth in the OATT in order to avoid being in default of Idaho Power's unreasonable delay damages provision in the FESAs. Yet Idaho Power has refused to follow that process, and instead has materially frustrated Exergy's ability to complete the interconnection.

Your letter sent June 12, 2012 is yet another example. Idaho Power Transmission apparently believes it is not capable of having the interconnection complete in time for the deadline in the FESAs, or the 90 days thereafter Idaho Power has provided for Exergy to cure any delay "default" prior to Idaho Power's right (again, under the FESAs it drafted) to terminate the FESAs. Exergy reasonably proposed to use a common procedure from Section 5.1.3 of Idaho Power's OATT to self build the interconnection. That would at least place Exergy in control of the interconnection construction, and consequently the related ability to achieve online status accordance with the FESAs. There is no basis for denial of this request. Exergy and its partners clearly have the capacity to self construct the interconnection process.

Your reliance on the terms and provisions of a state-jurisdictional Schedule 72 are unavailing. First, Idaho Power has consented to use the procedures of the OATT by course of conduct. Those provisions were used in correspondence between Exergy and Idaho Power to make the necessary modifications to the Interconnection Request No. 327 beginning in April 2011. You claim that Exergy failed to adhere to some "comment period" that Idaho Power has created. However, even if Idaho Power could foist an unfair process on an interconnecting generator for some failure to provide comments, we understand that Exergy has communicated its intent to use the OATT provisions consistently from the start. Idaho Power cannot indiscriminately "cherry pick", using some provisions of the OATT favorable to itself at some points and completely ignoring OATT at other times whenever Idaho Power chooses.

Second, and more importantly, the Schedule 72 process as applied is inconsistent with federal and state QF regulations. Idaho Power is discriminating against and providing less protection to the interconnection rights of QFs than those available for non-QF generators. As you are well aware, "a state may only take action under PURPA to the extent that that action is consistent with [FERC's] rules." *Cedar Creek Wind, LLC*, 137 FERC 61,006, ¶ 27 (2011). Federal Energy Regulatory Commission (FERC) regulations and case precedent is abundantly clear that well-established interconnection protections afforded under PURPA are intended to prevent the type of discriminatory treatment exhibited by Idaho Power here (e.g. 18 C.F.R. § 292.301 - 314). By prohibiting Exergy from self-building its QFs' interconnection in the same manner Idaho Power is required to allow non-QF generators under the OATT, Idaho Power is using the Schedule 72 process as an unreasonable shield to discriminate against Exergy, subverting and contorting the very purpose of Schedule 72.

Finally, a duty of good faith and fair dealing is implied in any contract. *Indep. Sch. Dist. of Boise City v. Harris Family Ltd. P'ship*, 150 Idaho 583, 589, 249 P.3d 382, 388 (2011). The four FESAs at issue here are no exception. Idaho Power has unreasonably demanded that, in order for Exergy to exercise its state and federal right to sell to Idaho Power as a QF, Exergy must agree to a delay default damages provision that required Exergy to post substantial security in excess of three million dollars for these Projects. Idaho Power claims in other forums that it does not need the output from wind projects at this time. Yet here Idaho Power refuses to slightly extend the online date in Exergy's FESAs. For Idaho Power to insist upon building the interconnection itself under deadlines that will not meet the deadlines Idaho Power refuses to move in the FESA is a transparent attempt to terminate the FESAs. Idaho Power cannot pretend as though it is two different entities. Idaho Power's intent is clear. No court would view Idaho Power's conduct as anything other than a monopolist utility's attempt to terminate the FESAs. As such, Idaho Power's actions are a clear breach of the implied covenant of good faith and fair dealing.

Idaho Power's entire course of conduct including its actions, inactions and interactions with Exergy regarding the interconnection procedures with respect to its four QF Projects and the related FESAs has the potential to cause tremendous harm to Exergy and seriously threatens the viability of these Projects. Earlier today, Exergy had delivered to Idaho Power executed counterparts of the relevant Interconnection Agreements. We are expecting Idaho Power to execute and deliver counterparts of Interconnection Agreement to Exergy as soon as possible. If this is not completed by the close of business on Monday, June 18th or if Idaho Power formally or informally removes any of the Projects from its interconnection queue, Exergy intends to pursue all available legal and equitable remedies against Idaho Power for all direct and indirect costs associated with these Projects, including the return of all security payments made under the FESAs, all hard and soft development and construction costs associated with the Projects, the value of all non-refundable deposits placed on wind turbines and other equipment, as well as other consequential and punitive damages.

Sincerely,

P del Vecchio

Peter A. del Vecchio

cc. James Carkulis, Exergy Development Group of Idaho, LLC
Peter Richardson, Richardson & O'Leary

IDAHO POWER®
An IDACORP Company

DONOVAN E. WALKER
Lead Counsel
dwalker@idahopower.com

June 12, 2012

VIA ELECTRONIC & U.S. CERTIFIED MAIL
RETURN RECEIPT REQUESTED

James Carkulis
Exergy Development Group
802 West Bannock Street, 12th Floor
Boise, Idaho 83702

Re: Jack Ranch Projects – Your June 12, 2012, E-Mail to Josh Harris

Dear Mr. Carkulis:

This letter responds to your e-mail of June 12, 2012, to Idaho Power's Josh Harris. As we have discussed several times and as you are fully aware, Idaho Power's Tariff Schedule 72 is the governing Tariff/document for PURPA QF Generator Interconnections to Idaho Power's system. Schedule 72 provides that "The Company [Idaho Power] will construct, own, operate and maintain all equipment, Upgrades and Relocations on the Company's electrical side of the Interconnection Point." IPUC No. 29, Tariff No. 101, Sheet No. 72-7. Schedule 72 does incorporate many provisions of the FERC-approved Large Generator and Small Generator Interconnection Procedures in the State Schedule 72 process. *See* IPUC No. 29, Tariff No. 101, Sheet No. 72-3, sub. 2. Only those provisions of the LGIA and SGIA that are not addressed by Schedule 72 are applicable in this state jurisdictional generator interconnection process. Any provisions of the LGIA and/or SGIA that purport to allow a QF project to construct any facilities used in any way to serve any other Idaho Power customer "on the Company's electrical side of the Interconnection Point" are not applicable as Schedule 72 requires such facilities to be constructed, owned, operated, and maintained by Idaho Power. We have specifically discussed this requirement on more than one occasion in our face-to-face meetings regarding your Jack Ranch projects, as well as several of your other projects with Idaho Power.

Additionally, the provision you cite to in the LGIA (5.1.3) – if it were applicable in this situation – applies only to Stand Alone Network Upgrades. As mentioned above, and as discussed with you previously, any facilities that are involved with the provision of service by Idaho Power to any other customers are not Stand Alone Upgrades, and

1221 W. Idaho St. (83702)
P.O. Box 70
Boise, ID 83707

must be constructed by Idaho Power pursuant to Schedule 72. This includes the interconnection facilities and upgrades for the Jack Ranch projects.

Further, as we discussed and as you requested, specific language consistent with what Idaho Power has contracted for with other QF interconnections – specifically the Thousand Springs GIA – was included in the final GIA, which we provided to you on May 14, 2012. Those additional provisions would allow Idaho Power to work cooperatively with you and bring to bear the assistance of third-party contractors and other methods to reasonably expedite the required work for your interconnection and upgrades. The Thousand Springs GIA language that you referenced is as follows:

> This is a revised date, upward in time from 1/15/11, based upon Interconnection Customer's needs and requests. Idaho Power will use reasonable efforts to have IPC's commissioning completed by 12/31/10. This revised completion date is contingent upon all materials being delivered on their scheduled delivery dates, the transmission line outage occurring as scheduled, receiving all necessary local, state and federal permits, including FERC and NEPA, and construction & regional resources being available.
>
> The parties hereby acknowledge that Idaho Power shall not be liable for any possible damages associated in any way with Renewable Energy Credits or Attributes, the firm energy sales agreements, and the like, attributable to Interconnection Customer, or any of the various projects named on page one of the GIA, should the 12/30/10 date not be met.
>
> Under normal efforts to bring the projects online a normal amount of overtime is utilized. Because of the Interconnection Customer's desire to meet an IPC commissioning date of 12/31/10, Interconnection Customer hereby authorizes IPC to incur additional expenses, including additional overtime, lodging, travel, and other expenses needed to bring in other IPC resources and personnel from other IPC regions as necessary to work on this interconnection.

The corresponding language that appears in the Jack Ranch GIA is as follows:

> Customer has requested an in-service date of 12/15/2012. Idaho Power does not commit to this date but will use reasonable efforts to have commissioning complete by

> 6/9/2014. This date is contingent upon all materials being delivered in a timely manner, as well as other factors, some of which are described above. The parties hereby acknowledge that Idaho Power shall not be liable to for any possible damages associated in any way with Renewable Energy Credits or Attributes, tax credits, the firm energy sales agreements, and the like, attributable to Customer, or any of the various projects named on page one of this GIA, should the 6/9/2014 date not be met.
>
> Under normal efforts to bring the projects online a normal amount of overtime is utilized. Because of the Customer's desire to meet an IPC commissioning prior to 6/9/2014, Customer hereby authorizes IPC to incur additional expenses, including additional overtime, lodging, travel, and other expenses needed to bring in other IPC resources and personnel from other IPC regions, or to utilize third party contractors, as necessary to work on this interconnection.

As evidenced by the language quoted above and included in the Final GIA for the Jack Ranch projects, as long as Exergy is willing to pay the associated additional cost, Idaho Power will use commercially reasonable efforts – including additional resources of its own, third-party contractors, and other steps to expedite the required interconnection work. However, as has been previously communicated to you in writing, even with the use of such measures to expedite, Idaho Power's estimate is a minimum of 18 months from payment of funds and execution of the Final GIA to complete the necessary system upgrades and interconnection facilities. As stated in Idaho Power's April 13, 2012, letter to you:

> As stated, Idaho Power will use commercially reasonable efforts, and work with you to expedite the construction of your interconnection facilities, including the use of third-party contractors – and including additional costs – if authorized and borne entirely by Exergy – to expedite the work required to interconnect your project to Idaho Power's system, allowing its energization. However, so as to be clear, I must reiterate that this does not change Idaho Power's estimate of a minimum of 18 months from payment of funds and execution of the GIA to complete the necessary system upgrades and interconnection facilities required to energize your project on Idaho Power's system, and even given the other uncertainties involved, it could take longer than 18 months still.

Your comment and request to include a provision consistent with the Thousand Springs GIA was received by Idaho Power during the appropriate 30-day comment period on the Jack Ranch Draft GIA. Idaho Power has incorporated your requested language into the Jack Ranch Final GIA to extent that Schedule allows. Your additional request at this late hour to include language from Idaho Power's LGIA is not only inappropriate, as the time for comment on the Draft GIA has passed, but it also has been previously and specifically discussed, addressed, resolved. Unfortunately, your request in your most recent e-mail appears to be another transparent attempt to now set up legal claims against Idaho Power that have no merit, while purporting to proceed in good faith and in a commercially reasonable manner – similar to those referenced in Idaho Power's June 8 letter to you.

Finally, as a reminder, pursuant to the May 14, 2012, letter to you from Idaho Power's Tess Park, and confirmed by Idaho Power's letter dated June 8, 2012, and now this letter as well, "Failure to submit an executed copy of the enclosed Final GIA, which includes the estimated milestones for the completion of construction, and complete the necessary financing arrangements for the Jack Ranch Projects **by June 13, 2012,** will result in Idaho Power terminating your generator interconnection request and withdrawing the Jack Ranch Projects from the generator interconnection queue."

Sincerely,

Donovan E. Walker

DEW:csb

cc: Lisa Grow, Idaho Power (via e-mail)
Tess Park, Idaho Power (via e-mail)
Randy Allphin, Idaho Power (via e-mail)
Jason Williams, Idaho Power Corporate Counsel (via e-mail)

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An IDACORP Company

DONOVAN E. WALKER
Lead Counsel
dwalker@idahopower.com

June 8, 2012

VIA ELECTRONIC & U.S. CERTIFIED MAIL
RETURN RECEIPT REQUESTED

James Carkulis
Exergy Development Group
802 West Bannock Street, 12th Floor
Boise, Idaho 83702

Re: Jack Ranch Projects – Your Letter Dated June 1, 2012

Dear Mr. Carkulis:

This letter responds to your letter dated June 1, 2012, to Lisa Grow wherein you again make a request that Idaho Power Company ("Idaho Power") agree to extend the June 30, 2012, Scheduled Operation Dates that you selected and obligated your projects to in the Firm Energy Sales Agreements ("FESAs") for each of the Jack Ranch Projects (i.e., Cottonwood Wind Park, Deep Creek Wind Park, Rogerson Flats Wind Park, and Salmon Creek Wind Park). As we have previously communicated to you, Idaho Power does not agree to extend those dates.

Your most recent allegation that Idaho Power agreed to a December 2011 on-line date from a generator interconnection standpoint and that you relied on Idaho Power's representation of a December 2011 generator interconnection date is absolutely without merit. December 2011 was the date selected by the Exergy Development Group ("Exergy") when it submitted its Small Generator Interconnection Request Application Forms and the Interconnection Request for a Large Generating Facility on March 12, 2010. Importantly, Exergy submitted five generator interconnection requests on March 12, 2010. GI 322, 223, 324, and 235 were each for 20 megawatt ("MW") projects and GI 327 was for a single 200 MW project. Exergy subsequently withdrew the requests for GI 322, 323, and 324, leaving GI 325 and GI 327.

The Generator Interconnection Feasibility Study provided to Exergy for GI 325 and 327 by Idaho Power on July 28, 2010 ("Feasibility Study"), states "The proposed in-service date is December, 2011." This statement is merely a factual recital of the in-service date requested by Exergy when it submitted its generator interconnection application forms for the Jack Ranch Projects. The same is true with the Generator Interconnection System Impact Study provided to you by Idaho Power on December 29, 2010 ("System Impact Study"), which states, "The proposed in-service date for this project is December, 2011." Again, this language was included as a mere recitation of what Exergy requested when it submitted its generator interconnection forms. Nowhere in those documents does Idaho Power represent, let alone agree, that the generator interconnection facilities for the Jack Ranch Projects would be constructed and on-line by December 2011. Indeed, Idaho Power has never represented to Exergy that the Jack Ranch Projects would be on-line by December 2011.

In fact, Idaho Power communicated to you on multiple occasions, both verbally and in writing, that Exergy was proceeding at its own risk in signing FESAs in December 2010 with a Scheduled Operation Date of June 30, 2012, prior to Idaho Power completing the necessary generator interconnection and transmission studies to determine how long it would take to construct and/or upgrade such facilities as well as the cost of such facilities. Specifically, in a letter dated November 17, 2010 (nearly one month prior to you executing the FESAs) to Exergy's attorney, Peter J. Richardson, Idaho Power told Exergy that:

> It was Idaho Power's understanding that Mr. Carkulis wished to get the results of the required interconnection and transmission studies, which will identify the need for and cost of interconnection facilities and possible transmission upgrades, prior to the time at which he would sign a Firm Energy Sales Agreement ("FESA") which would obligate the projects to a Scheduled Operation Date. As you are aware, the FESA contains provisions providing for delay damages should the projects fail to meet the Scheduled Operation Date set forth in the FESA. These delay damages are secured by the requirement to post liquid delay damage security thirty (30) days subsequent to IPUC approval of the FESA. As you are also aware, it is your client's responsibility to work with Idaho Power's Delivery business unit to ensure that sufficient time and resources will be available for Delivery to construct the interconnection facilities, and transmission upgrades if required, in time to allow the projects to achieve the Scheduled Operation Date set forth in the FESA. As Mr. Carkulis has previously been advised, delays in the interconnection or transmission process do not constitute excusable delays in achieving the Scheduled Operation Date, and, if the projects fail to achieve the Scheduled Operation Date at the times specified in the FESA, delay damages will be assessed. It was for this

> reason that Idaho Power was of the understanding that your client was not yet ready to commit to the execution of a FESA.
>
> If this is not the case, and if your client wishes to proceed forward with the execution of a FESA prior to completion of the interconnection and transmission studies and accept the associated risk thereto, then Idaho Power can send you a draft PURPA Wind FESA that contains the most recent and up-to-date "standard" terms and conditions that have been approved by the IPUC.

Letter from Donovan E. Walker to Peter J. Richardson dated November 17, 2010, at pp. 1-2.

On November 23, 2010, Exergy's attorney responded to Idaho Power's November 17, 2010, letter by stating:

> As you requested, I write to confirm that Exergy, as the developer for [the Jack Ranch Projects], is willing to sign contracts including the standard $45/kw delay liquidated damages clause prior to completion of the entire interconnection and transmission process for these projects, including Idaho Power internal processes required to designate the resource as a network resource. Exergy understands that, under the current standard contract Idaho Power would agree to enter into, a delay in achieving the online date caused by the interconnection or transmission processes is a delay which will not excuse a possible trigger in the delay damages clause.

Letter from Peter J. Richardson to Donovan E. Walker dated November 23, 2010.

The very next day, on November 24, 2010, Idaho Power sent draft FESAs to Exergy's attorney, including a cover letter which stated, in part:

> Your letter also confirms and acknowledges that your client wishes to move forward with the FESA, including the standard, Idaho Public Utilities Commission ("Commission") approved $45 per kilowatt of project capacity delay security, prior to completion of the interconnection and transmission studies and processes. Further, that your client understands it is their responsibility to work with Idaho Power's Delivery business unit to ensure that sufficient time and resources will

> be available for Delivery to construct the interconnection facilities, and transmission upgrades if required, in time to allow the projects to achieve the Scheduled Operation Date that the projects will commit themselves to in the FESA. In addition, your client has been advised, and accepts the risk, that delays in the interconnection or transmission process do not constitute excusable delays in achieving the Scheduled Operation Date, and if the projects fail to achieve the Scheduled Operation Date at the times specified in the FESA, delay damages will be assessed, and delay security applied. Please allow me to suggest that special consideration be given to the Scheduled Operation Date selected by the projects for inclusion and the FESA, such that with the information available at this time a date is chosen that has a good probability of providing time for the anticipated interconnection and possible transmission upgrades to be completed.

Letter from Donovan E. Walker to Peter J. Richardson dated November 24, 2010.

In response, Exergy's attorney sent a letter stating, in part:

> Exergy is fully aware of the contracts' provisions and, as you know has successfully developed many projects using the standard Idaho Power contract. Exergy is also fully aware of transmission and interconnection risks, as well as the liquid security provision.

Letter from Peter J. Richardson to Donovan E. Walker dated November 29, 2010.

This series of correspondence demonstrates that not only did Exergy have actual notice of the risks associated with selecting a Scheduled Operation Date in the FESAs without knowing the time frames or costs associated with interconnection and transmission facilities for the Jack Ranch Projects, Exergy affirmatively acknowledged and accepted those risks. With actual knowledge and affirmative acceptance of these risks, Exergy selected a Scheduled Operation Date of June 30, 2012, in each of the FESAs, which Exergy executed on December 10, 2010, and which were ultimately approved by the Idaho Public Utilities Commission on February 11, 2011.

In addition, as a sophisticated developer of generation projects and having previously developed more than a dozen other PURPA QF wind projects on Idaho Power's system, Exergy is fully aware of the studies Idaho Power must conduct as well as the processes necessary for generators, such as the Jack Ranch Projects, to connect to Idaho Power's system. In addition, Exergy is fully aware from its previous development projects with Idaho Power that the factual recitation of the proposed dates by a generator contained in the Feasibility Study and System Impact Study are in no way a guarantee by Idaho Power nor even a representation by Idaho Power as to when generator interconnection facilities will be on-line.

Further, after executing the FESAs, but prior to Idaho Power issuing the Facilities Study for the Jack Ranch Projects, Exergy requested that Idaho Power make significant changes to the generator interconnection facilities configuration for the Jack Ranch Projects, which required Idaho Power to restudy a large portion of the Jack Ranch Projects. Specifically, on April 12, 2011, Exergy sent Idaho Power a letter requesting several revisions to the Jack Ranch Projects, including reducing Exergy's GI 327 from 200 MW to 84 MW with an option to reduce the interconnection even further to 63 MW at some point in the future. Further, Exergy requested that the point of interconnection for the Cottonwood Wind Park, Deep Creek Wind Park and Rogerson Flats Wind Park be changed from an Idaho Power 138 kilovolt ("kV") line to a 345 kV line. Idaho Power responded via letter dated April 27, 2011, that a request of this type required Idaho Power to conduct a material modification review under Idaho Power's Large Generator Interconnection Procedures. Idaho Power further clarified that the change in the voltages from 138 kV to 345 kV for three of the four Jack Ranch Projects would require a restudy of the Facilities Study that was then in progress due to the different integration voltages and the associated different Idaho Power transmission lines. *See* letter dated May 20, 2011, from Dave Angell to James Carkulis. These significant changes requested by Exergy caused delays in the Jack Ranch Project's generator interconnection process.

Idaho Power is disappointed in reviewing your June 1, 2012, letter in that it contains many known misstatements of fact in an attempt to contend that Idaho Power, and not Exergy, was responsible for any delay that has occurred and the ultimate failure of Exergy to meet the Scheduled Operation Date that Exergy set for itself. Your letter is a transparent attempt to now, at this late hour, set up legal claims against Idaho Power that have no merit, while purporting to proceed in good faith and in a commercially reasonable manner. For example, at the end of your June 1 letter you state "each of the Project Companies has made, in good faith and based on the information provided by Idaho Power Company in the aforementioned studies, the applicable security deposits with the assumption that Idaho Power Company would be able to construct the interconnection facilities on the schedule originally set by the interconnection studies." This statement is incorrect.

First, Exergy has completely failed to, and has not to this day, paid the required construction deposit, nor executed the required Generator Interconnection Agreement ("GIA") in order for Idaho Power to proceed with any of the required detailed design, engineering, ordering of materials, and construction of the interconnection facilities and/or transmission upgrades. What Exergy has paid are the required deposits for Idaho Power to conduct the mandatory studies (Feasibility Study, System Impact Study, and Facilities Study), none of which provide a valid time line unless and until Exergy executes the required GIA and pays the requisite construction deposit for work to begin. Second, as stated above, as a sophisticated developer of generation projects and having previously developed more than a dozen other PURPA QF wind projects on Idaho Power's system, Exergy is fully aware of the studies Idaho Power must conduct as well as the processes necessary for generators, such as the Jack Ranch Projects, to connect to Idaho Power's system. Exergy is fully aware that the recitation in Section 4 of the Feasibility Study Report of what Exergy requested as an on-line date in its Generator Interconnection Application (December 2011) is not a representation by Idaho Power that the required work – which at the Feasibility Study stage is still unknown – can be accomplished by any date certain.

Additionally, even if Idaho Power were to agree, which it certainly does not, to change the Scheduled Operation Date in the FESAs, you have requested December 1, 2012, as the new Scheduled Operation Date. Further you state that this December 2012 date is consistent with the interconnection agreements applicable to each Project. The December 2012 date is most definitely NOT consistent with the anticipated time line, construction, and upgrades required of the interconnection of the Jack Ranch Projects. As clearly stated in the final GIA transmitted to you on May 14, 2012, "Idaho Power does not commit to this date [December 15, 2012] but will use reasonable efforts to have commissioning complete by 6/9/2014." Consequently, your requested change in the Scheduled Operation Date, even if agreeable to Idaho Power, would not resolve the problem that exists today, with Exergy insisting upon a Scheduled Operation Date that is before the time at which the Jack Ranch Projects' interconnection could be completed.

Lastly, as a reminder, per the May 14, 2012, letter to you from Idaho Power's Tess Park, "Failure to submit an executed copy of the enclosed Final GIA, which includes the estimated milestones for the completion of construction, and complete the necessary financing arrangements for the Jack Ranch Projects **by June 13, 2012,** will result in Idaho Power terminating your generator interconnection request and withdrawing the Jack Ranch Projects from the generator interconnection queue."

Sincerely,

Donovan E. Walker

DEW:csb

cc: Lisa Grow, Idaho Power (via e-mail)
Tess Park, Idaho Power (via e-mail)
Randy, Allphin, Idaho Power (via e-mail)
Jason Williams, Idaho Power Corporate Counsel (via e-mail)

01 June 2012

Lisa A. Grow
Senior Vice President, Power Supply
Idaho Power Company
PO Box 70
Boise, Idaho 83707

Re: Cottonwood Wind Park – Project #31721100, Deep Creek Wind Park – Project # 31721200, Rogerson Flats Wind Park – Project # 31721300 and Salmon Creek Wind Park – Project # 31721400

Dear Ms. Grow,

Each of Cottonwood Wind Park, LLC, Deep Creek Wind Park, LLC, Rogerson Flats Wind Park, LLC and Salmon Creek Wind Park LLC (collectively, the "Project Companies") has entered into an individual Firm Energy Sales Agreement with Idaho Power Company dated December 10, 2010 (collectively, the "Project PPAs").

I am writing this letter on behalf of the Project Companies to ask that Idaho Power Company amend Appendix B (Facility and Point of Delivery) of each of the Project PPAs such that Section B – 3 (Scheduled First Energy and Operation Date) reads as follows:

> "Seller has selected **November 1, 2012** as the Scheduled First Energy Date
> Seller has selected **December 1, 2012** as the Scheduled Operation Date"

The current schedule given by Idaho Power Transmission is December 2013.

This amendment will result in the schedule of the Project PPAs being consistent with each of the interconnection agreements applicable to each of the projects.

The parties originally agreed to June 30, 2012 as the Scheduled Operation Date because Idaho Power Company had originally provided the Project Companies with an initial on-line date of December 31, 2011 based on the interconnection studies. Specifically, the Generator Connector Feasibility Study final report dated July 28, 2010 for projects queue # 325 and queue #327 completed by Idaho Power Company is premised upon a proposed in-service date of December 2011 (See Section 4.0 of the final report). Moreover, the Generator Connector System Impact Study final report dated December 29, 2010 for projects queue #325 and queue #327 completed by Idaho Power Company is also based on the same proposed in-service date of December 2011 (See Section 4.0 of the final report).

The information we've received from Idaho Power Company in these studies has triggered many events. The project companies left sufficient room to build from the energization date of December 2011 of the substation to completion under the PPA. The project companies have been in continuous construction of these projects since December of 2011 based in large part on the information from Idaho Power Company contained in these studies. For example, the project companies have ordered substation equipment, readied the transformer to ship, built roads and excavated foundations, among other things. It was reasonable for the project companies to take these actions based on the fact that we were getting this information from Idaho Power Company. We hope that we have not relied on this information to our detriment.

Based on the results the studies delivered from Idaho Power Company, the parties included six months of contingency (should Idaho Power Company experience any delays in the construction of the necessary interconnection facilities) and, thus, the June 30, 2012 date was included in each of the Project PPAs. The Project Companies entered into the Project PPAs (with the aforementioned dates) based in large part on the information provided by Idaho Power Company. The Project Companies acted in good faith and in a commercially reasonable manner based on the information that Idaho Power Company provided.

Now that Idaho Power Company has made the Project Companies aware that the interconnection facilities will not be completed in order to allow the Project Companies to meet the Scheduled Operation Date, I am asking simply to have the dates in the Project PPAs reflect what Idaho Power Company is telling us that they will accomplish regarding the interconnection facilities.

Please note, each of the Project Companies has made, in good faith and based on the information provided by Idaho Power Company in the aforementioned studies, the applicable security deposits with the assumption that Idaho Power Company would be able to construct the interconnection facilities on the schedule originally set by the interconnection studies. The Project Companies have been diligently trying to work with Idaho Power Company to overcome this delay, but it is beyond the control of the Project Companies.

If you agree with the amendment, please respond appropriately and I will have the appropriate amendments drafted for each of the Project PPAs. I am very appreciative of your consideration and would ask for a resolution as soon as possible.

Sincerely,

James T. Carkulis
Manager of each of the Project Companies

Cc: Idaho Power Company, Cogeneration and Small Power Production

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 62

IDAHO POWER®
An IDACORP Company

July 3, 2012

VIA ELECTRONIC & U.S. MAIL
jcarkulis@exergydevelopment.com

James Carkulis
Exergy Development Group
802 West Bannock Street, 12th Floor
Boise, Idaho 83702

Re: Jack Ranch Projects – Rogerson Flats, Cottonwood, Deep Creek, and Salmon Creek Wind Parks – Failure to Meet Scheduled Operation Date

James:

The Scheduled Operation Date in Appendix B of the Firm Energy Sales Agreements ("FESA") for each of the above-referenced projects was June 30, 2012. Please be advised that as of today's date, July 3, 2012, none of the four projects have achieved their Scheduled Operation Date. Section 5.3.1 of the FESAs provides that:

> If the Operation Date occurs after the Scheduled Operation Date but on or prior to ninety (90) days following the Scheduled Operation Date, Seller shall pay Idaho Power Delay Liquidated Damages calculated at the end of each calendar month after the Scheduled Operation Date as follows:
>
> > Delay Liquidated Damages are equal to ((Current month's Initial Year Net Energy Amount as specified in paragraph 6.2.1 divided by the number of days in the current month) multiplied by the number of days in the Delay Period in the current month) multiplied by the current month's Delay Price.

Additionally, Section 5.3.2 of the FESAs states:

> If the Operation Date does not occur within ninety (90) days following the Scheduled Operation Date, the Seller shall pay Idaho Power Delay Liquidated Damages, in addition to those provided in paragraph 5.3.1, calculated as follows:

1221 W. Idaho St. (83702)
P.O. Box 70
Boise, ID 83707

> Forty five dollars ($45) multiplied by the Maximum Capacity with the Maximum Capacity being measured in kW.

Please be advised that pursuant to the provisions of Section 5.4 of the FESAs, if the projects fail to achieve the Operation Date within ninety (90) days following the Scheduled Operation Date, such failure will be a Material Breach of the FESAs and Idaho Power Company ("Idaho Power") may terminate the FESAs at that time. Without waiving any claims or rights pursuant to the FESAs or otherwise, Idaho Power acknowledges receipt of Exergy Development Group's ("Exergy") claim of force majeure related to these projects on June 29, 2012. Idaho Power does not agree with Exergy's claim of force majeure, and will be responding to the same separately.

Please contact Randy Allphin with any questions related to these contracts.

Sincerely,

John Anderson
Balancing Operations Manager

JA:csb
cc: Donovan Walker, Idaho Power
Jason Williams, Idaho Power
Randy Allphin, Idaho Power

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 63

RECEIVED
JUL 10 2012
By Christa Bearry
Hand delivered

RICHARDSON & O'LEARY, PLLC
ATTORNEYS AT LAW

Peter Richardson

Tel: 208-938-7901 Fax: 208-938-7904
peter@richardsonandoleary.com
P.O. Box 7218 Boise, ID 83707 - 515 N. 27th St. Boise, ID 83702

July 10, 2012

Via Hand Delivery and Electronic Mail

Donavon Walker
Legal Department
Idaho Power Company
1221 West Idaho Street
Boise, ID 83702

RE: Exergy Development Group of Idaho, LLC's Interconnection Nos. 325 and 327

Dear Donovan:

As you know, Exergy has expressed its intent that the Final Generator Interconnection Agreement for the above-referenced queue numbers include the right to self-build the interconnection embodied in Article 5.1.3 of the Standard Large Generator Interconnection Agreement ("LGIA") contained as Appendix 6 to Idaho Power's OATT. Exergy made its intent clear well prior to the time that Idaho Power purported to remove Interconnection Nos. 325 and 327 from Idaho Power's interconnection queue.

This interconnection is subject to the jurisdiction of, and governed by the rules of, the Federal Energy Regulatory Commission ("FERC"). Therefore, it was inexcusable for Idaho Power to unilaterally terminate negotiations after the parties were unable to agree on an in-service date and Exergy reasonably requested use of a standard term from the LGIA. Instead, Idaho Power should have submitted the Unexecuted Generator Interconnection Agreement with FERC for resolution of all disputed issues.

Thus, Exergy requests that Idaho Power immediately file the Unexecuted Generator Interconnection Agreement with FERC for resolution of the disputed issues. Thank you in advance for your prompt attention to this letter.

Sincerely,

Peter J. Richardson

Peter J. Richardson
Richardson & O'Leary PLLC

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 64

exergy
DEVELOPMENT GROUP

July 13, 2012

Idaho Power Company
Attn: Randy Allphin
1221 West Idaho Street
Boise, ID 83702

VIA E-MAIL AND HAND DELIVERY

RE: Jack Ranch Notices of Force Majeure

Dear Randy:

With reference to that certain letter sent by John Anderson to the undersigned, James Carkulis, dated July 3, 2012, (re: Jack Ranch Projects - Rogerson Flats, Cottonwood, Deep Creek and Salmon Creek Wind Parks - Failure to Meet Scheduled Operation Date) on behalf of Deep Creek Wind Park, LLC, Rogerson Flats Wind Park, LLC, Salmon Creek Wind Park, LCC, and Cottonwood Wind Park, LLC (collectively referred to as the "Jack Ranch Projects"), I respond to you, as directed by Mr. Anderson in his letter, as follows:

1. Thank you for the acknowledgement by Idaho Power of its receipt of Jack Ranch Projects' Notice of Force Majeure on June 29, 2012, as noted in the penultimate paragraph of Mr. Anderson's letter. Jack Ranch Projects respectfully acknowledges Idaho Power's stated position of disagreement therewith. However, it is Jack Ranch Projects' position that Idaho Power's receipt of the Notice of Force Majeure, regardless its disagreement therewith, nonetheless imposes a suspension of all parties' performance for the duration of the event of force majeure.

This is not a case of Jack Ranch Projects being in default of any FESA prior to giving the Notice of Force Majeure.

This is not a case where Jack Ranch Projects' tender or posting of a security is conditioned upon a requested performance by Idaho Power. As previously noted in the Notice of Force Majeure, all required security deposits as of the Notice of Force Majeure have been posted.

This is a case, however, where the Notice of Force Majeure has been given in compliance with Article XIV of the FESAs, with the particulars of the occurrence of Force Majeure set forth therein.

2. Without limitation upon the foregoing, and with the express non-waiver of and the express reservation of any and all rights and remedies under the FESAs, as well as any and all rights and remedies otherwise available to Jack Ranch Projects, including pursuant to FERC intervention

exergy DEVELOPMENT GROUP

with respect to FERC jurisdictional matters, and including by statute, tort or contract law, the following is specifically called to your further attention:

(i) The Notice of Force Majeure previously given and received by Idaho Power is incorporated herein by this reference thereto, in all respects as if fully set forth herein. A suspension of all parties' performance has been put into effect. Idaho Power's disagreement with respect thereto does not affect that suspension. If Idaho Power disputes this, then pursuant to Section 19.1 of the FESAs, Idaho Power is contractually obligated to submit the matter to the Commission for resolution. Idaho Power has no ability to resolve the matter in its own favor simply by unilateral fiat.

(ii) In clarity of the particulars of the GIA related events of Force Majeure as set forth in the Notice of Force Majeure, it is the position of Jack Ranch Projects that the reasonable reliance of Jack Ranch Projects on the Scheduled Operation Date and its ability to achieve same were bolstered by the fact that both the generation side of Idaho Power and the transmission side of Idaho Power had knowledge of the Scheduled Operation Date and the projected interconnection completion date on Idaho Power's side, and that each side of Idaho Power was aware that the manipulation of the date of Idaho Power's interconnection work completion to a later time would not square with the Scheduled Operation Date, would cause an impossibility of performance on the part of Jack Ranch Projects to meet its Scheduled Operation Date, and would cause the failure of Jack Ranch Project to achieve the Operation Date so as to allow Idaho Power to be able to allege a Material Breach under Section 5.4 of the FESAs as threatened in Mr. Anderson's letter.

(iii) Of particular note is the fact that pending IPUC Case No. GNR-E-11-03 discloses, among other things, the ongoing attempt by Idaho Power to modify provisions of the FESAs with respect to curtailment and REC ownership, thereby engaging in what is perceived by Jack Ranch Projects to be anticipatory breach by Idaho Power of Section 23.1 of the FESAs which disallows modification without a writing signed by both all parties. The unilateral attempt by Idaho Power to obtain through Commission intervention substantive modification of the FESAs makes it impossible for Jack Ranch Projects to further perform with any certainty its obligations under the FESAs. Accordingly, in addition to the unilateral activities of Idaho Power (which are beyond the control of Jack Ranch Projects and clearly not within the reasonable foresight of Jack Ranch Projects so as to have been avoided by the exercise of due diligence by Jack Ranch Projects) being within the definition of Force Majeure, the unilateral activities of Idaho Power also create grounds for the declaration by Jack Ranch Projects of anticipatory breach by Idaho Power of its obligations under the FESAs, not only with respect to Section 19.1, but also, without limitation, with respect to Idaho Power's implicit obligation of good faith and fair dealing under the FESAs. Jack Ranch Projects therefore reserves the right to give formal Notice of Default under Section 19.2 of the FESAs with respect to the foregoing anticipatory breach of Idaho Power, pending its further consideration of same.

Please be guided accordingly.

Sincerely,

Cottonwood Wind Park, LLC
Deep Creek Wind Park, LLC
Rogerson Flats Wind Park, LLC
Salmon Creek Wind Park, LLC
By: Exergy Development Group, LLC
James Carkulis, Managing Member

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 65

Perkins Coie

1201 Third Avenue, Suite 4900
Seattle, WA 98101-3099
PHONE: 206.359.8000
FAX: 206.359.9000
www.perkinscoie.com

Brendan J. Peters
PHONE: (206) 359-8132
FAX: (206) 359-9132
EMAIL: BPeters@perkinscoie.com

July 17, 2012

BY U.S. MAIL AND FACSIMILE

Peter A. del Vecchio
McGuireWoods LLP
Houston, TX 77002-2906
Facsimile: (713) 571-9652

Re: Jack Ranch Projects
Deep Creek Wind Park, LLC
Salmon Creek Wind Park, LLC
Rogerson Flats Wind Park, LLC
Cottonwood Wind Park, LLC

Dear Mr. del Vecchio:

I am writing on behalf of Idaho Power Company ("Idaho Power") in response to Exergy Development Group of Idaho, LLC's "Notice of Force Majeure" dated June 28, 2012 and to your letter dated June 13, 2012 addressed to Donovan Walker of Idaho Power.

In its Notice of Force Majeure, Exergy contends that Idaho Power's estimated date for construction of interconnection facilities is a Force Majeure event under the four Firm Energy Sales Agreements ("FESAs") between Idaho Power and Deep Creek Wind Park, LLC, Salmon Creek Wind Park, LLC, Rogerson Flats Wind Park, LLC, and Cottonwood Wind Park, LLC (the "Jack Ranch Projects"). Idaho Power, however, does not accept Exergy's assertion of an event of Force Majeure under paragraph 14.1 of the FESA.

Paragraph 14.1 states, in relevant part:

> As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the control of the Seller or of Idaho Power which, despite the exercise of due diligence, such Party is unable to prevent or overcome. Force Majeure includes, but is not limited to, acts of God, fire, flood, storms,

> wars, hostilities, civil strife, strikes and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, or changes in law or regulation occurring after the Effective Date, which, by the existence of reasonable foresight such party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome.

As defined by this paragraph, an event of Force Majeure must be something that was reasonably unforeseen by the parties. Specifically, Force Majeure events are defined as those that a party "by the exercise of reasonable foresight . . . could not reasonably have been expected to avoid." Here, not only was delay to the interconnection process foreseeable, but Exergy expressly and repeatedly agreed to assume the risk for delay.

For example, on November 17, 2010—one month prior to the parties' execution of the FESAs—Mr. Walker informed Exergy's counsel that Exergy was proceeding at its own risk in signing the FESAs in December 2010 given that Idaho Power had not yet completed the necessary generator interconnection and transmission studies to determine how long it would take to construct the facilities. The November 17, 2010 letter states in part:

> It was Idaho Power's understanding that Mr. Carkulis wished to get the results of the required interconnection and transmission studies, which will identify the need for and cost of interconnection facilities and possible transmission upgrades, prior to the time at which he would sign a Firm Energy Sales Agreement ("FESA") which would obligate the projects to a Scheduled Operation Date. As you are aware, the FESA contains provisions providing for delay damages should the projects fail to meet the Scheduled Operation Date set forth in the FESA. These delay damages are secured by the requirement to post liquid delay damage security thirty (30) days subsequent to IPUC approval of the FESA. As you are also aware, it is your client's responsibility to work with Idaho Power's Delivery business unit to ensure that sufficient time and resources will be available for Delivery to construct the interconnection facilities, and transmission upgrades if required, in time to allow the projects to achieve the Scheduled Operation Date set forth in the FESA. As Mr. Carkulis has previously been advised, delays in the interconnection and transmission process do not constitute excusable delays in achieving the Scheduled Operation Date, and, if the projects fail to achieve the Scheduled Operation Date at the times specified in the FESA, delay damages will be assessed. It was for this reason that Idaho Power was of the understanding that your client was not yet ready to commit to the execution of a FESA.
>
> If this is not the case, and if your client wishes to proceed forward with the execution of a FESA prior to completion of the interconnection and transmission studies and accept the associated risk thereto, then Idaho Power can send you a

> draft PURPA Wind FESA that contains the most recent and up-to-date "standard" terms and conditions that have been approved by the IPUC.

In response to the November 17, 2010 letter, Exergy's attorney wrote on November 23, 2010 to confirm that a delay to the interconnection process was not excusable:

> As you requested, I write to confirm that Exergy, as the developer of [the Jack Ranch Projects], is willing to sign contracts including the standard $45/kw delay liquidated damages clause prior to completion of the entire interconnection and transmission processes for these projects, including Idaho Power internal processes required to designate the resource as a network resource. Exergy understands that, under the current standard contract Idaho Power would agree to enter into, a delay in achieving the online date caused by the interconnection or transmission processes is a delay which will not excuse a possible trigger in the delay damages clause.

In reply to Exergy's acknowledgment of the uncertainty of the timeframe for the interconnection process, on November 24, 2010, Idaho Power delivered draft FESAs to Exergy's attorney with a cover letter stating in part:

> Your [November 23, 2010] letter also confirms and acknowledges that your client wishes to move forward with the FESA, including the standard, Idaho Public Utilities Commission ("Commission") approved $45 per kilowatt of project capacity delay security, prior to the completion of the interconnection and transmission studies and processes. Further, that your client understands it is their responsibility to work with Idaho Power's Delivery business unit to ensure that sufficient time and resources will be available for Delivery to construct the interconnection facilities, and transmission upgrades if required, in time to allow the projects to achieve the Scheduled Operation Date that the projects will commit themselves to in the FESA. In addition, your client has been advised, and accepts the risk, that delays in the interconnection or transmission process do not constitute excusable delays in achieving the Scheduled Operation Date, and if the projects fail to achieve the Scheduled Operation Date at the times specified in the FESA, delay damages will be assessed, and delay security applied. Please allow me to suggest that special consideration be given to the Scheduled Operation Date selected by the projects for inclusion in the FESA, such that with the information available at this time a date is chosen that has a good probability of providing time for the anticipated interconnection and possible transmission upgrades to be completed.

On November 29, 2010, Exergy's attorney responded to Idaho Power's November 24, 2010 letter and emphasized that Exergy accepted the interconnection risks, stating:

> Exergy is fully aware of the contracts' provisions and, as you know has successfully developed many projects using the standard Idaho Power contract. <u>Exergy is also fully aware of the transmission and interconnection risks, as well as the liquid security provision</u>.

(Emphasis added). The correspondence discussing the timing of the interconnection process demonstrates that the potential for delay in the interconnection process could have been reasonably foreseen. As a result, the date for construction of the interconnection facilities cannot be an event of Force Majeure under paragraph 14.1 of the FESA.

The type of events listed in paragraph 14.1 also shows that an event of Force Majeure was not intended to cover the actions of one of the contracting parties. Paragraph 14.1 expressly identifies the following as Force Majeure events: "acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, or changes in law or regulation occurring after the Effective Date." All of these events are attributable to either actions of third parties or to "acts of God"—not to either Exergy or Idaho Power. Thus, simply put, an event of Force Majeure under paragraph 14.1 cannot by definition include the other party's performance under the FESA.

This is especially true with respect to the timing of the interconnection process because under the FESA, *both parties* have to accept that a delay constitutes a Force Majeure event. Paragraph 5.3 of the FESA provides that "Delays in the interconnection and transmission network upgrade study, design and construction process that **<u>are not</u>** Force Majeure events accepted by both Parties, **<u>shall not</u>** prevent Delay Liquidated Damages from being due and owing as calculated in accordance with this Agreement." If one party to the FESA could simply contend—as Exergy does in its Notice of Force Majeure—that the other party's performance constitutes a Force Majeure event, it would then make no sense that the FESA requires that *both parties* accept the delay as a Force Majeure event. Thus, a party's performance under the FESA cannot constitute an event of Force Majeure, and Idaho Power does not accept Exergy's proposition that a Force Majeure event has occurred.

Exergy has also failed to provide Idaho Power with timely notice of an event of Force Majeure as required under paragraph 14.1(1) of the FESA, which requires that "The non-performing Party shall, as soon as is reasonably possible after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence." In the August 11, 2011 Draft Generator Interconnection Facility Study Report, Idaho Power stated that the date for the "IPCO Construction Complete" milestone was "18 Months after Construction Funds are Received by IPCO." Idaho Power provided this same information again in both its December 6, 2011 Final

Generator Interconnection Facility Study Report and the February 15, 2012 Revised Final Generator Interconnection Facility Study Report. After receiving this information *more than ten months ago*, Exergy did not provide a notice of Force Majeure. Instead, Exergy waited until Friday, June 29, 2012 to provide a Notice of Force Majeure—*the day before* Exergy was obligated to achieve the Scheduled Operation Date. The timing of the Notice of Force Majeure shows that it simply represents Exergy's unsuccessful last-minute attempt to try to avoid responsibility for failing to achieve the June 30, 2012 Scheduled Operation Date.

In addition to Exergy's failure to provide timely notice of a Force Majeure event, Exergy has also failed to specify with particularity what occurrence constitutes the event of Force Majeure. In paragraph 5 of its Notice of Force Majeure, Exergy asserts that Idaho Power's "refusal to agree to a reasonable change in the Scheduled Operation Date is clearly 'beyond the control of the Seller' . . . and is, therefore within the definition of Force Majeure[.]" Exergy's contention, however, is not correct because paragraph 23.1 of the FESA provides that a contract modification must be agreed to *by both* contracting parties *and subsequently approved by the Commission.* Under Exergy's logic, any modification under paragraph 23.1 would constitute an event of Force Majeure because approval is outside of the control of Exergy. This one example shows that the event Exergy contends is a Force Majeure fails under the FESA and as a matter of logic.

Exergy's impossibility argument also cannot stand because the doctrine of impossibility depends on the unforeseen act of a third party. *See, e.g., Haessly v. Safeco Title Ins. Co. of Idaho*, 121 Idaho 463, 465, 825 P.2d 1119 (1992) ("The doctrine of impossibility operates to excuse performance when the bargained-for performance is no longer in existence or is no longer capable of being performed due to the unforeseen, supervening act of a third party."). In this matter, the potential delay to the construction of the interconnection was accepted as a risk by Exergy prior to execution of the FESAs and does not implicate the act of a third party.

Like an event of Force Majeure under the FESA, the event triggering an impossibility defense must not have been foreseeable by the parties. *See, e.g., Haessly*, 121 Idaho at 465. As explained above, the possibility of delay in the interconnection process was foreseeable, especially in light of the parties' communications in November and December of 2010 prior to execution of the FESAs. Additionally, one of the essential elements of an impossibility defense is proof that the non-occurrence of the claimed event was a basic assumption of the contract. *See, e.g.*, Restatement (Second) of Contracts § 261 (1981); *Haessly*, 121 Idaho at 465 (requiring proof that "the nonoccurrence of the contingency must be a basic assumption of the agreement" for an impossibility defense). Here, in light of the extensive pre-FESA communications between the parties, Exergy cannot legitimately contend that the non-occurrence of delays in interconnection process was a basic assumption on which the FESAs were executed.

Similar to Exergy's assertion of Force Majeure, Exergy's reliance on the impossibility doctrine does not apply because Exergy explicitly assumed the risk of delays in the interconnection process. *See, e.g.*, 30 Williston on Contracts § 77:41 (4th ed. 2004) ("Supervening impracticability of the kind that usually excuses performance will not do so if the terms of the promise, interpreted in the light of surrounding circumstances and usages, indicate that the promisor assumes the risk."); *City of Boise v. Bench Sewer Dist.*, 116 Idaho 25, 30, 773 P.2d 642 (1989) ("[A] contract embodies the choice of a planned future over the risk that subsequent events may cause the plan to become undesirable for one of the parties. The law generally enforces such choices because, even though a particular agreement may prove to be improvident, contracts as a whole benefit society by contributing to the rational ordering of human affairs. Equity will not intervene unless a contract is unlawful, violates public policy, or produces unconscionable harm[.]").

In your letter, you also contend that Idaho Power has "materially frustrated Exergy's ability to complete the interconnection." To the contrary, it has been Exergy's actions—including decisions Exergy made during the interconnection study process—that have resulted in what Exergy now contends is a delay in the interconnection process. Among other things, these Exergy-caused delays prevent Exergy from asserting Force Majeure and impossibility defenses. A couple of Exergy's actions during the interconnection study process are illustrative.

The FESA provides that the interconnection process must be in accordance with Schedule 72's Generation Interconnection Process. Under Schedule 72, a seller is offered a series of three study agreements. These individual study agreements establish the time for performance of the studies. The last study is referred to as the Facility Study, and the completion of this Study is an important milestone because the Facility Study is required before a seller is offered a Generator Interconnection Agreement. IPCU No. 29, Tariff No. 101, Sheet No. 72-4 (stating "The Generator Interconnection Agreement ("GIA"), will be offered to Seller following completion of the Facility Study.").

After the Jack Ranch Project's System Impact Study was completed, Exergy was offered an Interconnection Facility Study Agreement in January 2011. Notably, Exergy delayed a month in executing the Facility Study Agreement. Critically here, Attachment A of the Facility Study Agreement provides an interconnection customer with a choice to either have the Draft Generator Interconnection Facility Study Report completed within 90 days, or 180 days. Instead of choosing to have the Draft Facility Study Report issued within 90 days, Exergy instead opted for the longer-track to have the study completed in 180 days. This decision by Exergy alone injected three-months of delay in the interconnection process. Moreover, it shows that had Exergy truly been interested in a brisk interconnection process, Exergy could have opted for completion of the Draft Facility Study Report in 90 days.

By choosing the 180-day option, the Draft Facility Study Report was scheduled to be completed within 180 days of receipt of the executed copy of the Interconnection Facility Study Agreement, or in August 2011. In accordance with the 180-day timeframe selected by Exergy in the

Interconnection Facility Study Agreement, the Draft Generator Interconnection Facility Study Report was sent to Exergy on August 11, 2011. Because of proposed changes to the interconnection requested by Exergy in the summer of 2011, however, the Final Generator Interconnection Facility Study Report did not issue until December 2011. On December 15, 2011, Idaho Power sent Exergy a draft Generator Interconnection Agreement. At this point, Exergy could have decided to proceed with executing the GIA and depositing the required funds and the interconnection design and construction process could have potentially commenced in 2011. Instead of executing the GIA in December 2011, however, Exergy continued to make proposed changes to the interconnection during the winter months of 2011/2012. These proposed changes by Exergy in turn required Idaho Power to conduct restudies, which ultimately resulted in a Revised Final Generator Interconnection Facility Study Report on February 15, 2012.

Exergy's decision to request a Facility Study Report in 180 days instead of 90 days, and Exergy's proposed interconnection changes during the period between the August 2011 Facility Study Report and the February 2012 Revised Final Generator Interconnection Facility Study Report, are just two examples representing at least 9 months of delay injected into the interconnection process by Exergy.

Thus, there is no basis for Exergy's contention that Idaho Power frustrated Exergy's timely completion of the interconnection process. Exergy's actions—including its delay of the study process described above, its failure to execute a GIA, and its refusal to pay required pre-construction deposits—have resulted in significant delays to the interconnection process. Exergy's contentions based on Force Majeure, impossibility, or a lack of good faith are inapposite given that the delays to the interconnection process have been caused by Exergy.

In addition to providing a couple of representative examples of Exergy's delay to the interconnection process and explaining why Idaho Power does not consider the timing of the interconnection a Force Majeure Event or create the "impossibility" of Exergy's performance, we also write to address numerous misstatements in the Notice of Force Majeure and in your June 13th letter.

First, the assertions in paragraph 1 of the Notice of Force Majeure are incorrect—Idaho Power did not establish "interconnection facilities and upgrade construction completion dates as occurring in December 2011." As explained more fully in Mr. Walker's June 8, 2012 letter to Exergy, the Generator Interconnection Feasibility Study provided to Exergy for GI 325 and 327 by Idaho Power states that "The proposed in-service date is December, 2011." This statement is simply a recital of the service date requested in Exergy's March 12, 2010 Generator Interconnection Request Application Form, which states: "Interconnection Customer's Requested In-Service Date: December, 2011." As Mr. Walker explained in his letter, Idaho Power did not represent in the studies that the generator interconnection facilities would be constructed and on-line by December 2011. Mr. Walker also explained that Exergy was aware from its experience on other Idaho Power projects that the recitation of the interconnection customer's proposed date is not a representation of when interconnection facilities would be on-line.

The second paragraph of the Notice of Force Majeure also contains numerous misstatements. For example, Idaho Power did not "unilaterally" decide to conduct further studies. Idaho Power has conducted three types of studies for the Jack Ranch Projects: (1) the Feasibility Study; (2) the System Impact Study; and (3) the Facility Study. These three types of studies are the same studies identified in the Schedule 72 General Interconnection Process. IPCU No. 29, Tariff No. 101, Sheet No. 72-4. Idaho Power also did not "move" any dates forward. As provided in the August 11, 2011 Draft Generator Interconnection Facility Study Report, Idaho Power indicated that the milestone for "Construction Complete" would be 18 months after construction funds were received by Idaho Power. This milestone remained unchanged in the December 6, 2011 Final Facility Study Report, and again in the February 15, 2012 Revised Final Generator Interconnection Facility Study Report. Significantly, after receiving the Final Generator Interconnection Facility Reports, Exergy did not object to the 18-month timeframe. And, as Mr. Bauer's April 10, 2012 letter explains, Idaho Power has consistently advised Exergy that the lead-time on the interconnection facilities is a minimum of 18-months from receipt of construction financing. Therefore, Idaho Power has not "moved" dates as Exergy incorrectly asserts.

Third, Exergy's contention that Idaho Power has "refused" to sign the GIA is also not correct. On April 10, 2012, Idaho Power sent a Generator Interconnection Agreement to Exergy for review. Exergy, however, did not provide any edits to the GIA. As a result, on May 14, 2012, Idaho Power sent Exergy a signature-ready GIA for execution. Instead of signing the final GIA, however, Exergy modified the GIA and inserted a new Section 8.3 Option to Build provision into the modified GIA without disclosing this change to Idaho Power. Exergy then signed this modified GIA. Exergy's proposed option to build provision, however, is not in compliance with Schedule 72's requirements. As part of the general requirements for interconnected projects, Schedule 72 mandates that "The Company will construct, own, operate and maintain all equipment, Upgrades and Relocations on the Company's electrical side of the Interconnection Point." IPCU No. 29, Tariff No. 101, Sheet No. 72-7. Additionally, as Idaho Power previously informed Exergy, even if the requested option to build provision from section 5.1.3 of the Standard Large Generator Interconnection Agreement in the OATT applied, which it does not, it only applies for Stand Alone Network Upgrades. "Interconnection Customer shall have no right to construct Network Upgrades under this option." As Exergy is aware, Schedule 72 contains the Uniform Interconnect Agreement for PURPA QF interconnections to Idaho Power's system, and the Standard Large Generator Interconnection Agreement from the OATT is not used for QF interconnections. Thus, as explained in Mr. Walker's June 18, 2012 letter, the option-to build provision is not an acceptable term for a GIA under Schedule 72. Exergy has still failed to sign the final GIA sent to Exergy on May 14, 2012. Until Exergy executes the final GIA and pays the required deposit, construction of the interconnection facilities cannot commence.

In your June 13th letter, you also state that "Idaho Power has unreasonably demanded that, in order for Exergy to exercise its state and federal right to sell to Idaho Power as a QF, Exergy must agree to a delay default damages provision that required Exergy to post substantial security in excess of three million dollars for these Projects." You assert that this somehow equates to a breach of the duty of good faith. This assertion is false.

As you know, a breach of a duty of good faith does not arise simply when an entity exercises its express contract rights. *See First Sec. Bank of Idaho v. Gaige*, 115 Idaho 172, 176, 765 P.2d 683 (1988) ("[W]e agree with the trial court's ruling that First Security did not breach any duty to Gaige by merely exercising its express rights under the guaranty agreement. There is no basis for claiming implied terms contrary to express rights contained in the parties' agreement."). This is because the duty of good faith cannot override the express terms of a contract. *See Idaho First Nat'l Bank v. Bliss Valley Foods, Inc.*, 121 Idaho 266, 288, 824 P.2d 841 (1991) ("No covenant will be implied which is contrary to the terms of the contract negotiated and executed by the parties."). Here, Article V of the FESA contains a delay default damages provision. Likewise, Paragraph 5.4 expressly provides that Idaho Power may terminate the FESA if Exergy fails to achieve the Operation Date within ninety (90) days following the Scheduled Operation Date. Idaho Power is simply standing on its express rights in the FESA. Idaho Power, therefore, rejects your suggestion that it breached the duty of good faith by acting in accordance with the FESA terms.

It is also important to note that the trigger for delay default damages is connected to the Scheduled Operation Date—*a date selected by Exergy*, not Idaho Power. In your letter, you correctly recognize that Exergy had the ability to input the date itself in the FESA. In making this decision, paragraph 2.1 of the FESA explicitly states that "Seller has investigated and determined that it is capable of performing hereunder and has not relied upon the advice, experience or expertise of Idaho Power in connection with the transactions contemplated by this Agreement." Thus, under the FESA, Exergy had an obligation to perform its own investigation and determine—without relying on Idaho Power—that it could meet the Scheduled Operation Date. By having control over the Scheduled Operation Date inserted into Exhibit B of the FESA, Exergy had the ability to appropriately calibrate its risk for delay to the interconnection process depending on how quickly it moved forward with the study process and the extent to which it made proposed changes along the way. Exergy cannot now assert it has been harmed by relying on Idaho Power to make decisions that were entrusted to Exergy under the FESA.

Additionally, Idaho Power has taken reasonable measures to ensure that Exergy obtains the benefit of the FESAs. As described above, prior to execution of the FESAs, Idaho Power advised Exergy to select a Scheduled Operation Date that had a good probability of providing time for the interconnection upgrades. This year alone, Idaho Power has repeatedly informed Exergy that Idaho Power would use commercially reasonable efforts and work with Exergy to expedite the construction of Exergy's interconnection facilities and expedite the work required to interconnect the Jack Ranch Projects to Idaho Power's system. Exergy, however, has failed to avail itself of these proposed measures.

Exergy also asserts that it understood that Idaho Power would "be proceeding under the terms of the OATT for this interconnection." Any such understanding was in error. In the letter, dated November 24, 2010, from Mr. Walker to Peter Richardson, Idaho Power clearly stated that the interconnection would be pursuant to Schedule 72 (Interconnections to Non-Utility Generation). By its terms, service under Schedule 72 is available throughout Idaho Power's "service area within the State of Idaho to Sellers owning or operating Qualifying Facilities that sign a Uniform Interconnection Agreement . . . ." Thus, Exergy knew—or should have known—that Idaho Power was proceeding under the terms of Schedule 72 for this interconnection.

Moreover, FERC has stated that the relevant state authority exercises exclusive jurisdiction over interconnections in which the electric utility must purchase the entire output of the qualifying facility:

> When an electric utility is obligated to interconnect under Section 292.303 of the Commission's Regulations, *that is, when it must purchase the QF's total output, the relevant state authority exercises authority over the interconnection and the allocation of interconnection costs.*

Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 813 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007)). Recently, FERC has reaffirmed the finding that it will have jurisdiction over an interconnection with a qualifying facility only if the host utility is given notice that third-party sales of the facility's output are occurring or are planned:

> Therefore, consistent with our conclusions in *Niagara Mohawk*, where a host utility is not given notice that third-party sales of output are occurring or are planned (e.g., through a QF's request for wheeling service or a contract providing the QF an express right to sell output to third parties), we will assume that all sales of a QF's output are being made to the host utility and therefore that Commission jurisdiction will not attach.

Florida Power & Light Co., 133 FERC ¶ 61,121 at P 22 (2010) (citing *Niagara Mohawk Power Corp.*, 121 FERC ¶ 61,183 (2007), *order denying reh'g*, 123 FERC ¶ 61,061 (2008)). Here, the

FESAs would obligate Idaho Power to purchase the entire output of the facilities. Therefore, the Idaho Public Utilities Commission—and not FERC—has jurisdiction over the interconnection.

In conclusion, Idaho Power does not accept Exergy's contentions set forth in the Notice of Force Majeure and your July 13th letter, including those based on Force Majeure, impossibility of performance, the duty of good faith and fair dealing, or alleged discriminatory treatment under PURPA.

Since sending your June 13th letter to Idaho Power, Exergy has submitted a "Notice of Force Majeure" to Idaho Power dated July 2, 2012, which relates to two Firm Energy Sales Agreements executed between Idaho Power and Lava Beds Wind Park, LLC and Notch Butte Wind Park, LLC. Exergy contends that the July 2, 2012 Notice of Force Majeure is "directly tied" to the Notice of Force Majeure dated June 28, 2012. Because Exergy has linked these two Notices, Idaho Power does not accept the July 2, 2012 Notice of Force Majeure for the same reasons set forth above.

Nothing in this letter shall be construed as a waiver of Idaho Power's rights under the FESAs or otherwise available by law. Idaho Power hereby expressly reserves all of its rights, including but not limited to its rights under paragraph 5.4 of the FESAs should Exergy fail to achieve the Operation Date for the Jack Ranch Projects within ninety days following the June 30, 2012 Scheduled Operation Date.

Sincerely,

Jason Kuzma for

Brendan J. Peters

cc: Thomas Banducci, Banducci Woodard Schwartzman PLLC
Jason Kuzma, Perkins Coie LLP
Christine Salmi, Perkins Coie LLP
Idaho Power Company
Peter Richardson, Richardson & O'Leary, PLLC

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-12-20

IDAHO POWER COMPANY

ATTACHMENT 66

IDAHO POWER®
An IDACORP Company

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July 24, 2012

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Re: Exergy Development Group of Idaho, LLC's Generator Interconnection Nos. 325 and 327

Dear Peter:

This correspondence responds to your July 10, 2012, letter to me regarding Generator Interconnection Nos. 325 and 327 for the Jack Ranch Projects. As Idaho Power Company ("Idaho Power") has explained to both you and your client on numerous occasions, the Jack Ranch Projects are not eligible for the "self-build" option under Article 5.1.3 of Idaho Power's Large Generator Interconnection Agreement contained in Idaho Power's Open Access Transmission Tariff. *See, e.g.*, Letter from Donovan E. Walker to James Carkulis dated June 12, 2012, and Letter from Donovan E. Walker to Peter J. Richardson dated June 18, 2012.

In addition, and as you are aware, the Idaho Public Utilities Commission ("Idaho PUC"), not the Federal Energy Regulatory Commission ("FERC"), has jurisdiction over qualifying facility ("QF") generators interconnecting to Idaho Power's system. *See,* Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 813 (2003), order on reh'g, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, order on reh'g, Order No. 2003-B, FERC Stats. & Regs, ¶ 31,171 (2004), order on reh'g, Order No. 2003-C, FERC Stats. & Regs. K 31,190 (2005), aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC, 475 F.3d 1277 (D.C. Cir. 2007). The generator interconnection process for QFs interconnecting to Idaho Power's system is governed by Idaho Power's Idaho PUC approved Schedule 72. Jurisdiction over any dispute related to Idaho Power's Schedule 72 is properly before the Idaho PUC. Accordingly, it would be inappropriate for Idaho Power to submit an unexecuted copy of the final generator interconnection agreement for the Jack Ranch Projects to FERC as FERC does not have jurisdiction over such disputes.

That said, under separate cover sent to you on today's date, Idaho Power has filed with the Idaho PUC a Complaint and Petition for Declaratory Order which asks the Idaho PUC to resolve all issues and disputes related to the Jack Ranch Projects, including the dispute related to the generator interconnection agreements.

Sincerely,

Donovan E. Walker

DEW:csb
cc: Jason Williams, Idaho Power (via e-mail)