Stantec Consulting Services Inc.
30 Park Drive, Topsham ME 04086-1737

August 14, 2015
File: 195600919

Mark Bergeron
Director, Bureau of Land Resources
Maine Department of Environmental Protection
17 State House Station
Augusta, Maine 04333

Reference: Information Requested for Site Location of Development and Natural Resources Protection Act Permit Applications, Number Nine Wind Farm LLC, DEP #L-26502-2F-A-N, #L-26502-24-B-N, #L-26502-IW-C-N, #L-26502-L6-D-N, #L-26502-VP-E-N, #L-26502-TH-F-N

Dear Mark,

Thank you for the opportunity to provide additional information on our Application. Although we are pleased to provide details, we had understood that the Department's determination of completeness for acceptance of an application is governed by its procedural rules (06-096CMR 2(11)(B)) and that

> *A determination that an application is accepted as complete for processing is based on staff's determination that the application fee has been paid pursuant to section 12 of this rule, that sufficient title, right or interest has been demonstrated pursuant to section 11(D), and that the application form is properly filled out and information is provided for each of the items required by the forms. It is not a review of the sufficiency of that information and does not preclude the Department from requesting additional information during processing or denying the application for failure to provide information necessary for the processing of that application.*

Our understanding of these rules indicates that our Application should be accepted as complete because we have made arrangements for payment of special fee provisions, demonstrated sufficient right, title or interest, and provided the information required by the forms. The "deficiencies" noted in your August 6, 2015 letter are requests for additional information, which we are happy to provide, but according to the rule, these are not matters affecting acceptance as complete.

As such, in response to your August 6, 2015 letter, we are providing the requested information for the following five points in support of the application for the Number Nine Wind Farm (Project):

1. Financial Capacity

a. The notes for the consolidated financial statements are included as Attachment A.

b. These statements were audited by KPMG LLP and their report, dated April 30, 2015, is included in Attachment A.

c. Section 3.2.1 of the Application explains that EDPR NA's parent company, EDPR, provides equity to EDPR NA on an as-needed basis for the development and construction of projects. On page 7 of Attachment A, the line entitled "Contribution of Equity from Parent" describes the contribution of cash provided to EDPR NA in 2013 and 2014 for development and construction project-based cash needs in those years. Note that cash is contributed on an as-needed basis.

d. A signed letter of commitment from EDPR is included as Attachment B.

2. Wildlife

a) The MDIFW recommendations noted in your letter are just that, evolving staff recommendations. They have not been through a legislative or public rulemaking process, and do not have the force of law. This Project has considered those recommendations and has an alternative approach which will be protective and advance the science around bat interactions with wind projects. Not adhering to MDIFW staff recommendations is not an incompleteness or deficiency in our application where an alternative is proposed.

As described in Section 7.8 of the application, the Applicant has analyzed the pre-construction data from the Project area, as well as available pre-construction bat studies and post-construction bat fatality monitoring from other wind facilities, and data suggest that bat fatality rates for the Project may be very low. In addition, given that no northern long-eared bats were recorded and very few little brown bats were recorded, the risk to *Myotis* is also expected to be very low. Nonetheless, the Applicant has committed to a site specific approach that will minimize the impact the Project may have on bats. The Applicant has provided a summary and synthesis of bat fatalities at wind facilities, with a focus on northeastern North America, in Exhibit 7-F1. This summary includes a review of 182 publicly available post-construction fatality studies. The summary also included a synthesis of studies conducted to investigate the effectiveness of curtailment treatments, as wind speed seems to be one of the main predictors of risk to bats at wind facilities. Data from these studies demonstrates that feathering turbine blades below wind speeds in the range of 4.0 to 4.5 m/s can reduce *Myotis* fatalities by 90% or more.

The Applicant has also provided a summary of the proposed curtailment and post-construction fatality monitoring methods in Exhibit 7-F2. As described in the application, the Applicant believes the proposed curtailment methods would be effective at reducing the risk of bat fatalities at the Project and would provide additional scientific information for evaluation and consideration of operational strategies to minimize bat fatalities at future projects.

3. Public Safety

a. Section 27.4 of the application describes the fire safety measures that are incorporated for the Project, and Exhibit 27-A, the DNV Certification, includes certification of the lightning protection system. Additional information on the fire safety features of the Gamesa G114 turbines are described in the two Engineering Coordination Memorandums from Gamesa included as Attachment C.

b. The Gamesa G114 turbines are designed to meet standards of the Confederation of Fire Protection Associations in Europe, as described in Attachment C.

c. The Operations and Maintenance building, located centrally in the Project area, will be staffed by 2 to 4 EDPR NA employees, including a High Voltage Specialist, as well as 8-10 Gamesa technicians, who will be responsible for monitoring turbine operations. These staff are also available 24/7 to provide on-site support in times of any Project emergency and will have the ability to locally and remotely receive substation SCADA alarms, as well as monitor and operate the Project's substation and generation equipment. The on-site staff will be supplemented by additional High Voltage specialists and regional Operations personnel employed by EDRP NA. All personnel permanently located at the Project will be equipped with industrial two-way radios, allowing very effective communications within the Project area. The Project will also be well-equipped with additional state-of-the-art equipment for emergency support, including land line and wireless telephones, as well as internet, e-mail, and fax access.

   EDPR NA maintains a Remote Operations Control Center (ROCC), located in Houston, Texas, that monitors and operates remotely EDPR NA facilities across the United States. The ROCC uses monitoring and control systems for the Project substation SCADA system and the wind turbines. ROCC services are available 24 hours a day, 7 days a week, and 365 days a year. ROCC staff are available to take action and be a communication hub in the event of an emergency. Gamesa also has a control center in Trevose, Pennsylvania and control center in Spain that will both also conduct 24/7 monitoring for the Project.

4. Tangible Benefits

a. The Applicant and the Aroostook County Commissioners are committed to finalizing documentation of a Tax Increment Financing (TIF) Development District that includes the Project (subject to final approval by the Department of Economic and Community Development pursuant to Chapter 206 of Title 30-A), and will provide the Department with finalized documents and agreements associated with this Development District in its review of the Project under the tangible benefit siting criteria (including estimates of new tax revenues generated by the Project).

   In addition, the Applicant expects to fully meet statutory community benefit requirements via agreements with Aroostook County and will provide the final form of the community benefit package documents to demonstrate compliance with 35-A MRSA Section 3454 (1) (D) & (2).

b. As described in Section 28.3.3, the Project will meet the requirements of the community benefits package with the agreement with the Aroostook County Commissioners. The $2

Reference: Information Requested for Site Location of Development and Natural Resources Protection Act Permit Applications, Number Nine Wind Farm LLC

million Aroostook County Residential Heating Improvement Program (Program) is in addition to the requirements of the community benefits package. The concept of this Program was developed in consultation with the Director of the Governor's Energy Office, Patrick Woodcock. At his suggestion, EDPR has been working with the Efficiency Maine Trust (EMT), and in particular the Executive Director of EMT Michael Stoddard, to develop documents needed to allow the Program to move forward. EMT will consult as needed with appropriate state offices. EDPR is also in communication with Douglas Beaulieu, the Aroostook County Administrator, regarding the program.

5. Decommissioning

a. Exhibit 29-A of the Application includes an explanation of the conservative estimates for scrap and salvage values that were incorporated into the decommissioning budget, which is summarized in Table 29-1 of the application. These values can be found on pages 9-10 of Exhibit 29-A.

We believe that this information addresses your information requests, and we look forward to working with the Department during the review of the application.

Regards,
STANTEC CONSULTING SERVICES INC.

Joy Prescott
Project Manager
Phone: (207) 406-5508
Fax: (207) 729-2715
joy.prescott@stantec.com

Attachments:
A: Consolidated Financial Statement with Notes
B: Letter of Commitment from EDPR
C: Fire Safety Features of the Gamesa G114 Turbines

c. Jessica Damon, MDEP
Katie Chapman, EDPR
Andy Hamilton, Eaton Peabody

ATTACHMENT A: CONSOLIDATED FINANCIAL STATEMENT WITH NOTES

EDP RENEWABLES NORTH AMERICA LLC AND SUBSIDIARIES

Consolidated Financial Statements

December 31, 2014 and 2013

(With Independent Auditors' Report Thereon)

EDP RENEWABLES NORTH AMERICA LLC AND SUBSIDIARIES

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KPMG LLP
811 Main Street
Houston, TX 77002

Independent Auditors' Report

The Managing Member
EDP Renewables North America LLC:

We have audited the accompanying consolidated financial statements of EDP Renewables North America LLC and subsidiaries, which comprise the consolidated statements of financial position as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for the years then ended, and the related notes to the consolidated financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America and International Standards on Auditing. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

KPMG

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of EDP Renewables North America LLC and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for the years then ended, in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

KPMG LLP

Houston, Texas
April 30, 2015

EDP RENEWABLES NORTH AMERICA LLC AND SUBSIDIARIES

Consolidated Statements of Financial Position

December 31, 2014 and 2013

(U.S. dollars in thousands)

Assets		**2014**	**2013**
Property, plant, and equipment (note 19)	$	6,247,921	5,812,760
Intangible assets (note 20)		93,859	89,039
Investment in associates (note 21)		181,500	194,651
Derivative instruments (note 33)		9,411	1,780
Deferred tax assets (note 18)		50,411	68,824
Debtors and other assets (note 24)		15,022	21,292
Total noncurrent assets		6,598,124	6,188,346
Inventories (note 22)		4,200	3,023
Trade receivables (note 23)		52,726	54,598
Derivative instruments (note 33)		13,342	9,239
Debtors and other assets (note 24)		54,385	55,111
Cash (note 25)		191,785	47,136
Total current assets		316,438	169,107
Total assets	$	6,914,562	6,357,453
Equity and Liabilities			
Equity:			
Additional paid-in capital	$	3,002,460	3,088,940
Accumulated other comprehensive income (loss)		3,042	(1,321)
Result of sale of noncontrolling interests, net of tax (note 26)		33,648	33,648
Retained earnings		266,211	169,800
Total equity attributable to equity holders of the Parent		3,305,361	3,291,067
Noncontrolling interests (note 26)		208,764	215,563
Total equity		3,514,125	3,506,630
Liabilities:			
Liabilities arising from institutional equity partnerships, net of transaction costs (note 27)		2,187,763	2,080,366
Provisions for liabilities and charges (note 28)		61,242	51,083
Derivative instruments (note 33)		9,434	3,617
Deferred income (note 31)		480,313	503,408
Trade and other payables (note 30)		2,191	2,228
Total noncurrent liabilities		2,740,943	2,640,702
Short-term financial debt (note 29)		—	1,665
Provisions for liabilities and charges (note 28)		110	110
Due to affiliates (note 32)		6,799	7,972
Derivative instruments (note 33)		8,586	14,644
Trade and other payables (note 30)		643,999	185,730
Total current liabilities		659,494	210,121
Total liabilities		3,400,392	2,850,823
Total equity and liabilities	$	6,914,562	6,357,453

See accompanying notes to consolidated financial statements.

EDP RENEWABLES NORTH AMERICA LLC AND SUBSIDIARIES

Consolidated Statements of Income

Years ended December 31, 2014 and 2013

(U.S. dollars in thousands)

		2014	2013
Generating revenue (note 5)	$	510,927	473,246
Income recognized from sale of interests in institutional equity partnerships (note 6)		164,203	166,145
Other income (note 7)		9,533	25,677
Supplies and services (note 8)		(153,520)	(154,642)
Personnel costs (note 9)		(31,484)	(31,821)
Employee benefits expenses (note 9)		(6,473)	(5,996)
Other expenses (note 10)		(36,122)	(49,811)
Income from operations		457,064	422,798
Provisions (note 11)		—	(1,550)
Depreciation and amortization expense (note 12)		(269,714)	(266,980)
Amortization of deferred income (note 14)		23,095	23,076
Impairment of tangible and intangible assets (note 13)		—	(1,053)
Other financial income (note 15)		19,121	11,917
Other financial expenses (note 15)		(96,851)	(98,802)
Share of gain (loss) of associates (note 16)		6,110	(209)
Income before tax		138,825	89,197
Income tax benefit (expense) (note 17)		(11,063)	11,359
Net income	$	127,762	100,556
Net income attributable to:			
Equity holders of the parent	$	96,411	75,025
Noncontrolling interests (note 26)		31,351	25,531
Net income	$	127,762	100,556

See accompanying notes to consolidated financial statements.

EDP RENEWABLES NORTH AMERICA LLC AND SUBSIDIARIES

Consolidated Statements of Comprehensive Income

Years ended December 31, 2014 and 2013

(U.S. dollars in thousands)

		2014	2013
Net income	$	127,762	100,556
Change in unrealized gains on derivative instruments (note 33)		4,363	906
Total comprehensive income	$	132,125	101,462
Total comprehensive income attributable to:			
Equity holders of the parent	$	100,774	75,931
Noncontrolling interests		31,351	25,531
Total comprehensive income	$	132,125	101,462

See accompanying notes to consolidated financial statements.

EDP RENEWABLES NORTH AMERICA LLC AND SUBSIDIARIES

Consolidated Statements of Changes in Equity

Years ended December 31, 2014 and 2013

(U.S. dollars in thousands)

	Additional paid-in capital	Accumulated other comprehensive income (loss)	Result of sales of noncontrolling interests, net of tax	Retained earnings	Equity attributable to equity holders of EDPR NA	Noncontrolling interests	Total equity
Balances as of December 31, 2012	$ 3,055,140	(2,227)	33,861	94,775	3,181,549	177,681	3,359,230
Contributions of equity	412,000	—	—	—	412,000	—	412,000
Distributions of equity	(378,200)	—	—	—	(378,200)	(34,115)	(412,315)
Unrealized gain on derivative instruments, net of tax	—	906	—	—	906	—	906
Sale of noncontrolling interest	—	—	51	—	51	46,466	46,517
Deferred tax on sale of noncontrolling interest	—	—	(264)	—	(264)	—	(264)
Net income	—	—	—	75,025	75,025	25,531	100,556
Balances as of December 31, 2013	3,088,940	(1,321)	33,648	169,800	3,291,067	215,563	3,506,630
Contributions of equity	175,470	—	—	—	175,470	—	175,470
Distributions of equity	(261,950)	—	—	—	(261,950)	(38,150)	(300,100)
Unrealized gain on derivative instruments, net of tax	—	4,363	—	—	4,363	—	4,363
Sale of noncontrolling interest	—	—	—	—	—	—	—
Deferred tax on sale of noncontrolling interest	—	—	—	—	—	—	—
Net income	—	—	—	96,411	96,411	31,351	127,762
Balances as of December 31, 2014	$ 3,002,460	3,042	33,648	266,211	3,305,361	208,764	3,514,125

See accompanying notes to consolidated financial statements.

EDP RENEWABLES NORTH AMERICA LLC AND SUBSIDIARIES

Consolidated Statements of Cash Flows

Years ended December 31, 2014 and 2013

(U.S. dollars in thousands)

		2014	2013
Cash flows from operating activities:			
Cash receipts from customers	$	514,565	479,742
Cash paid to suppliers		(138,107)	(131,812)
Cash paid to employees		(37,138)	(37,880)
Cash paid to landowners		(22,463)	(21,796)
Net receipts on derivative contracts		1,690	8,420
Restricted cash decrease (increase)		2,657	(3,273)
Other receipts (payments) relating to operating activities		(20,351)	3,722
Net cash provided by operating activities		300,853	297,123
Cash flows from investing activities:			
Proceeds from sale of property, plant, and equipment		—	1,565
Return of advances to fixed asset supplier		—	35,012
Return of electrical facility deposits		1,700	659
Proceeds from note receivable		439	440
Receipts from financial assets		41	634
Receipts from loans to affiliates		84	2,212
Receipt of distributions from associates		19,261	8,986
Interest received		543	341
Acquisition of property, plant, and equipment and intangible assets		(242,357)	(458,759)
Cash paid for electrical facility deposits		(180)	(850)
Net cash used in investing activities		(220,469)	(409,760)
Cash flows from financing activities:			
Receipts from loans and interest		—	3,000
Payments for loans and interest		(1,665)	(4,486)
Interest and similar costs		(5,901)	(7,052)
Government grants received		—	120,243
Contribution of equity from parent		175,470	412,000
Return of equity to parent		(261,950)	(378,200)
Proceeds from sale of interest in institutional equity partnerships		291,325	—
Repayments to institutional equity partnership investors		(92,499)	(47,252)
Payments for transaction costs related with institutional equity partnerships		(2,365)	—
Proceeds from sale of noncontrolling interests		—	48,400
Payments for transaction costs related with sale of noncontrolling interests		—	(1,883)
Distributions to noncontrolling interests		(38,150)	(34,115)
Net cash provided by financing activities		64,265	110,655
Net change in cash		144,649	(1,982)
Cash at beginning of year		47,136	49,118
Cash at end of year	$	191,785	47,136

See accompanying notes to consolidated financial statements.

(1) The Business Operations of EDP Renewables North America LLC

EDP Renewables North America LLC (EDPR NA or the Company) is a Delaware limited liability company, formed for the purpose of developing, constructing, and operating wind and solar powered electricity generating facilities. The Company is directly and wholly owned by EDP Renovaveis, SA (EDPR or the Parent), a majority held subsidiary of EDP SA – Sucursal Espana (EDP).

EDPR NA is dependent upon EDPR for its financing of capital expenditures. EDPR has indicated its commitment to provide or arrange additional funding for EDPR NA to satisfy current and future obligations on an as-needed basis.

The corporate headquarters is located in Houston, Texas.

(2) Accounting Policies

(a) Basis of Preparation

These consolidated financial statements reflect EDPR NA's and its subsidiaries' results from operations, cash flows, and the Company's interest in associated companies for the years ended December 31, 2014 and 2013, and the financial position as of the years then ended. Certain reclassifications have been made to the statements of financial position and income as a result of a change in accounting policy (note 2(s)). These consolidated financial statements are rounded to the nearest thousand and presented in U.S. dollars, which is the functional currency of the Company. The consolidated financial statements were authorized for issue by the management of EDPR NA on April 30, 2015.

These consolidated financial statements are prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB). IFRS comprise accounting standards issued by the IASB and its predecessor body as well as interpretations issued by the International Financial Reporting Interpretations Committee (IFRIC) and its predecessor bodies.

The consolidated financial statements have been prepared under the historical cost convention, modified by the application of fair value basis for derivative financial instruments, except those for which a reliable measure of fair value is not available. Recognized assets and liabilities that are hedged under hedge accounting are stated at fair value in respect of the risk that is being hedged.

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates, and assumptions that affect the application of the accounting policies and of the reported amounts of assets, liabilities, income, and expenses. The estimates and related assumptions are based on historical experience and other factors that are believed to be reasonable under the circumstances, the results of which form the basis of making the judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates. The issues involving a higher degree of judgment or complexity, or where assumptions and estimates are considered to be significant, are disclosed in note 3.

(b) Basis of Consolidation

The consolidated financial statements of EDPR NA comprise the assets, liabilities, and results of the Company, and its subsidiaries and the results from its associated companies attributable to the Company. All material intercompany transactions have been eliminated. These accounting policies have been consistently applied by all subsidiaries and associated companies in all years presented in the consolidated financial statements.

Subsidiaries

Investments in subsidiaries where EDPR NA has control are fully consolidated from the date EDPR NA assumed control over the financial and operational activities until the moment that control ends. Control is presumed to exist when EDPR NA owns more than half of the voting rights. Control also exists when EDPR NA has the power, directly or indirectly, to govern the financial and operating policies of the entity, so as to obtain benefits from its activities, even if its shareholding is less than 50%.

Associates

Investments in associates are accounted for by the equity method from the date on which significant influence was obtained until the date it ceases. Associates are entities over which EDPR NA has significant influence, but not control, over its financial and operating policies. Generally, when EDPR NA holds more than 20% of the voting rights of the investor, it is presumed that it has significant influence. If EDPR NA holds, directly or indirectly, less than 20% of the voting rights of the investor, it is presumed to not have significant influence, except when such influence can be clearly demonstrated.

Significant influence is normally demonstrated by one or more of the following ways:

- Representation on the Board of Directors or equivalent management committee
- Participation in the policy making processes, including participation in decisions over dividends and other distributions
- Existence of material transactions between EDPR NA and the investor
- Interchange of managerial personnel
- Provision of essential technical information

The consolidated financial statements include EDPR NA's attributable share of total reserves and results of associated companies accounted for under the equity method. When EDPR NA's share of losses exceeds its interest in an associate, EDPR NA's carrying amount is reduced to $0 and recognition of further losses is discontinued, except to the extent that the Company has a legal or constructive obligation to absorb those losses or make payments on behalf of the associate.

Noncontrolling Interest

Changes in the Company's interest in a subsidiary that do not result in a loss of control are accounted for as equity transactions (transactions with other owners in their capacity as owners). The controlling and noncontrolling interests are adjusted to reflect the changes in their relative interests in the subsidiary. Any difference between the amount by which the noncontrolling interests are adjusted and the fair value of the consideration paid or received are recognized directly in result of sale of noncontrolling interest, net of tax in equity and attributed to the owners of the Parent.

Balances and Transactions Eliminated on Consolidation

Intercompany balances and transactions, including any unrealized gains and losses on transactions between consolidated companies, are eliminated in preparing the consolidated financial statements. Unrealized gains and losses arising from transactions with associates and jointly controlled entities are eliminated to the extent of EDPR NA's interest in those entities.

(c) Foreign Currency Translation

Foreign currency transactions are translated at the exchange rates prevailing at the dates of the original transaction. Monetary assets and liabilities denominated in foreign currencies are translated into U.S. dollars at the foreign currency exchange rates at the reporting date. Foreign currency exchange differences arising on translation are recognized in the income statement.

(d) Financial Instruments

Nonderivative Financial Instruments

Nonderivative financial instruments comprise trade receivables, debtors and other assets, cash, financial debt, and trade, other payables, and due to affiliates.

Nonderivative instruments are recognized initially at fair value. Financial assets are assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows from that asset.

Derivative Financial Instruments

Derivative financial instruments are recognized on the trade date at fair value. Subsequently, the fair value of derivative financial instruments is remeasured, with the change in fair value recognized directly in the statement of income, except for those derivatives designated as hedging instruments. The recognition of the resulting gains or losses on remeasurement of the derivatives designated as hedging instruments depends on the nature of the risk being hedged and of the hedge model used.

The fair values of derivatives correspond to their quoted market prices, if available, or are determined by external entities and internally through the use of valuation techniques, including discounted cash flow models and options pricing models, as appropriate.

Hedge Accounting

The Company has used financial instruments to hedge foreign currency exchange risks resulting from its investing activities in prior periods and currently uses financial instruments to hedge changes in spot market power prices. Derivative financial instruments that do not qualify for hedge accounting are recorded as held for trading.

The derivatives that are designated as hedging instruments are recorded at fair value, with the gains and losses recognized in accordance with the hedge accounting model adopted by the Company. Hedge accounting is used when:

(i) At the inception of the hedge, the hedge relationship is identified and documented;

(ii) The hedge is expected to be highly effective;

(iii) The effectiveness of the hedge can be reliably measured;

(iv) The hedge is revalued on an ongoing basis and is considered to be highly effective over the reporting period; and

(v) The forecasted transactions hedged are highly probable and represent a risk to changes in cash flows that could affect future income.

The effective portion of the changes in the fair value of the derivative financial instruments that are designated as hedging instruments in a cash flow hedge is recognized in equity. The gains or losses relating to the ineffective portion of the hedging relationship are recognized in the statement of income in the period they occur.

The cumulative gains or losses recognized in equity are reclassified to the statement of income over the periods in which the hedged item affects the statement of income.

When a hedging instrument expires or is sold, when a hedge no longer meets the criteria for hedge accounting, or when management discontinues the hedge, any cumulative gain or loss recognized in equity at that time remains recognized in equity until the hedged transaction affects the statement of income. When the forecasted transaction is no longer expected to occur, the cumulative gains or losses recognized in equity are recorded in the income statement.

Effectiveness

For a hedge relationship to be classified as such, in accordance with IAS 39, *Financial Instruments: Recognition and Measurement*, its effectiveness must be demonstrated. Therefore, the Company performs prospective tests at the inception dates as well as prospective and retrospective tests on an ongoing basis to demonstrate the effectiveness at each reporting date, showing that any adjustments to the fair value of the derivative financial instruments are hedged by adjustments to the hedge instrument attributable to the risk being hedged. Ineffectiveness is recognized in the statement of income in the period it occurs.

(e) Property, Plant, and Equipment

Property, plant, and equipment (PP&E) is generally carried at acquisition cost less accumulated depreciation. Certain assets acquired prior to the Company's adoption of IFRS, which was January 1, 2006, are carried at deemed cost less accumulated depreciation. Subsequent costs are capitalized when it is probable that future economic benefits associated with the item will flow to the Company. All repair and maintenance costs are charged to the statement of income during the period in which they are incurred.

(Continued)

The Company assesses its PP&E for impairment whenever events or circumstances may indicate that the book value of these assets exceeds its recoverable amount. Any impairments would be recognized in the consolidated statements of income in the period identified.

Land is not depreciated. Depreciation on the other assets is calculated using the straight-line method over their estimated useful lives as follows:

	Years
Number of years:	
Plant and machinery	25
Buildings and other constructions	20
Transport equipment	3
Office equipment and tools	3–5
Other	3–5

(f) ***Depreciation methods, useful lives, and salvage values are reviewed at each reporting date and adjusted if appropriate. Intangible Assets***

The intangible assets of the Company are recorded at acquisition cost and are amortized over the term of the related agreement or useful life of the asset (note 20).

The Company assesses these assets for impairment whenever events or circumstances may indicate that the book value of these assets exceeds its recoverable amount. On assessment, any excess is recognized as a loss in the statement of income. The recoverable value is the higher of the asset's fair value less costs to sell or its value in use. Value in use is calculated from the fair value of the estimated future cash flows from the asset plus its sale price at the end of its economic useful life.

(g) ***Leases***

The Company classifies its lease agreements as either finance leases or operating leases, taking into consideration the substance of the transaction rather than its legal form. A lease is classified as a finance lease if it transfers to the lessee substantially all of the risks and rewards incidental to ownership. All other leases are classified as operating leases.

Operating Leases

Lease payments under operating leases are recognized as an expense in the period to which they relate.

Determining Whether an Arrangement Contains a Lease

In accordance with the IFRIC 4, *Determining Whether an Arrangement Contains a Lease*, the Company evaluates arrangements in order to identify if such arrangements contain a lease, as defined.

The existing arrangements that do not take the legal form of a lease but convey a right to use an asset in return for a payment, if meeting the conditions established by the referred interpretation, are accounted for in accordance with IAS 17, *Leases*.

(h) Inventories

Inventories are stated at weighted average cost. The Company's inventories consist of replacement parts that are not for resale, but are consumed during regular facility repairs and maintenance, and are charged to maintenance and repairs expense when placed in service (notes 8 and 22).

(i) Trade Receivables

Trade receivables are initially recognized at their fair value.

Impairment losses are recorded based on the valuation of estimated losses from noncollection of accounts receivable at the reporting date. Impairment losses are recognized in the statement of income, and can be reversed if the estimated losses decrease in a subsequent period. The Company has not recorded any impairment losses from trade receivables.

(j) Employee Benefits

Defined Contribution Retirement Plan

The Company maintains an employee retirement plan established under the terms of Section 401(k) of the U.S. Internal Revenue Code. Under this plan, employees may make voluntary contributions up to amounts established by this section. The Company matches contributions on a dollar-for-dollar basis up to 6% of compensation and has no obligations under this plan other than this matching contribution, which is recorded as an expense. All amounts contributed to this plan are held by a third-party trustee.

Bonus to Employees

Annually, EDPR, as sole member, may approve a discretionary bonus payment to be paid to the employees. Bonus payments to employees are recognized in the income statement in the period to which they relate.

(k) Provisions

Provisions are recognized when (i) the Company has a present legal or constructive obligation, (ii) it is probable that settlement will be required in the future, and (iii) a reliable estimate of the obligation can be made.

Dismantling and Decommissioning Provisions

The Company leases the majority of the land on which it places its generating equipment. The Company recognizes dismantling and decommissioning provisions for the expected cost of equipment removal and restoring sites and land to its original condition at the end of the lease term. The provisions correspond to the present value of the expenditure expected to be required to settle the obligation and are recognized as part of the initial cost or an adjustment to the cost of the respective assets, and depreciated on a straight-line basis over the asset's useful life.

Decommissioning and dismantling provisions are reviewed annually based on the best estimate of the anticipated cost. The accretion of the provision is recorded in the income statement. Adjustments to the provision values resulting from changes in accounting estimates are recognized as an adjustment to the cost of the respective asset.

(l) Revenue Recognition

Revenue from the sale of electricity is recognized in the period in which the electricity is delivered to customers at established prices.

Curtailment revenue is compensation received from power purchasers when those purchasers are unable to take power produced due to market or transmission issues. The Company recognizes curtailment revenue in the periods the power would have been generated and delivered.

The production of electricity at certain facilities results in the Company also producing Renewable Energy Credits (RECs). RECs are tradable environmental commodities and each credit represents proof that one megawatt hour (mwh) of electricity was generated from an eligible renewable energy resource. These credits can be sold or traded. RECs are recorded as revenue in the period the energy was generated if the Company has a firm sales contract in place. Generated RECs not under firm sales contracts are recognized as a current asset and deferred revenue at estimated current market prices until they are sold under an executed contract.

(m) Other Financial Income and Expenses

Other financial income and expenses comprise interest payable on borrowings, interest receivable on funds invested, dividend income, foreign exchange gains and losses, gains, as well as losses on financial instruments, and changes in fair value of derivative instruments not accounted for as hedges.

Interest income is recognized in the consolidated statements of income as it accrues.

(n) Income Tax

The Company has elected to be taxed as a corporation for federal and state income tax purposes. Income tax expense comprises current and deferred tax. Current tax and deferred tax are recognized in the consolidated statement of income except to the extent that it relates to a business combination, or items recognized directly in equity or in other comprehensive income.

Current tax is the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted as of the reporting date, and any adjustments to tax payable related to previous years.

Deferred tax is recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized for the following temporary differences:

- The initial recognition of assets or liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit or loss
- Differences relating to investments in subsidiaries and jointly controlled entities to the extent that it is probable that they will not reverse in the foreseeable future
- Temporary differences arising on the initial recognition of goodwill

Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted as of the reporting date. Deferred tax assets and liabilities are offset if there is a legal right to offset current tax liabilities and assets, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized for unused tax losses, tax credits, and deductible temporary differences, to the extent that it is probable that future taxable profits will be available against which they can be applied. Deferred tax assets are reviewed at each reporting date and are reduced for any portion that can no longer be considered probable that the related tax benefit will be realized.

(o) Cash

Cash comprises deposits with banks.

Certain of the Company's cash balances are contractually restricted for designated expenditures or used as collateral or credit support. Amounts in these accounts are classified as restricted cash in current debtors and other assets (note 24).

(p) Government Grants

The Company was previously eligible to receive grants from various governmental entities as an incentive to construct renewable energy generating facilities. These grants are generally based on a percentage of the cost of the facility. These grants, when received, were recorded as deferred revenue and are recognized over the remaining useful life of the related facility (note 14).

(q) Capitalization of Borrowing Costs

The Company capitalizes the cost of borrowed funds that are used to construct its projects. Direct costs of obtaining institutional equity partnership financing are capitalized as a reduction of liabilities arising from institutional equity partnerships, net of transaction costs, in the period incurred and are amortized over the life of the financing. Interest is capitalized as a component of PP&E beginning in the period in which the borrowed funds are used for asset additions.

(r) Financial Debt

Financial debt is initially recognized at fair value. Subsequent to initial recognition, financial debt is measured at amortized cost using the effective-interest method. Amounts payable within the next 12 months are classified as current. Interest expense is recognized in the period incurred.

(s) Change in Accounting Policy

IFRS 7 – Financial Instruments

The IASB amended IFRS 7 in December 2011 to improve the disclosures in netting arrangements associated with financial assets and financial liabilities. As a result, the Company has not identified any impact to the disclosures regarding the recognized financial assets or financial liabilities as of December 31, 2014.

IFRS 10 – Consolidated Financial statements

EDPR NA adopted IFRS 10 on January 1, 2013. IFRS 10 introduces a new control model that focuses on whether the Company has power over an investee, exposure, or rights to variable returns from its involvement with the investee and the ability to use its power to affect those returns. The Company reassessed the control conclusions for its investees as of January 1, 2013. The Company noted no change in its control conclusions in respect to its investments in its investees, and there has been no impact on the recognized assets, liabilities, or comprehensive income of the Company due to the adoption for the provisions of IFRS 10.

IFRS 12 – Disclosures of Interest in Other Entities

IFRS 12 calls for expanded disclosures about the Company's interests in its subsidiaries and equity accounted investments. The Company reviewed these new requirements and determined that no material changes to the disclosures were required.

IFRS 13 – Fair Value Measurement

IFRS establishes a single framework for measuring fair value and making disclosures about fair value measurements. When such measurements are required or permitted by other IFRSs, it unifies the definition of fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. It replaces and expands the disclosure requirements about fair value measurements in other IFRSs, including IFRS 7. As a result, the Company has included additional disclosures in this regard (See note 33).

In accordance with the transitional provisions of IFRS 13, the Company has applied the new fair value measurement guidance prospectively and has not provided any comparative information for new disclosures. Notwithstanding the above, the change had no significant impact on the measurement of the Company's assets and liabilities.

IAS 1 – Disclosures – Offsetting Financial Assets and Financial Liabilities

Amendments to IAS 1 required that items included in Other Comprehensive Income (OCI) be presented separately depending of if they would be reclassified to profit or loss or would remain in OCI. This comparative information is presented accordingly. The Company reviewed these new requirements and determined that no material changes to the disclosures were required.

IFRS 11 – Joint Arrangements

EDPR NA adopted IFRS 11 on January 1, 2013. IFRS 11 introduces a new model for the consolidation of joint arrangements, calling for the Company to classify its interests in joint arrangements as either a joint operation (if the Company has rights to the assets, and obligations for the liabilities relating to the arrangement) or a joint venture (if the Company has rights only to the net assets of an arrangement. When making this assessment, the Company considered the structure of the arrangements, the legal form of separate vehicles, the contractual terms of the arrangements and other facts and circumstances. Previously, the structure of the arrangement was the sole focus for the classification.

Prior to the adoption of IFRS 11, EDPR NA utilized the proportional consolidation method to report the results of operations, cash flows, and financial position of its 50% ownership interests in Flat Rock Windpower, LLC and Flat Rock Windpower II, LLC (note 21). Upon the adoption of IFRS 11, the Company reports these ownership interests as associates utilizing the equity method.

(3) Critical Accounting Estimates and Judgments in Applying Accounting Policies

IFRS set forth a range of accounting treatments that require management to apply judgment and make estimates in deciding which treatment is most appropriate.

The most significant of these accounting policies are discussed below in order to improve the understanding of how their application affects the Company's reported results and related disclosure. A broader description of the accounting policies employed by the Company is shown in note 2 to the consolidated financial statements.

The determination of fair value of long-term assets for impairment purposes (notes 13 and 19), amounts of liabilities arising from institutional equity partnerships (note 27), and provisions for liabilities and charges (note 28) require the use of assumptions and other sources of estimation uncertainty at the end of the period. Potential changes in these assumptions and estimations create a significant risk of material adjustment to the carrying amounts of assets and liabilities within the next fiscal year.

Because in many cases there are other alternatives to the accounting treatment chosen by management, the Company's reported results would differ if a different treatment was chosen. Management believes that the choices made by it are appropriate and that the consolidated financial statements present the Company's financial position and results fairly in all material respects. The alternative outcomes discussed below are presented solely to assist the reader in understanding the consolidated financial statements and are not intended to suggest that other alternatives or estimates would be more appropriate.

(a) Fair Value of Derivatives

Fair values are based on listed market prices, if available. Otherwise fair value is determined either by dealer price quotations (both for that transaction or for similar instruments traded) or by internally or externally generated pricing models, based on net present value of estimated future cash flows that take into account market conditions for the underlying instruments, time value, yield curves, and volatility factors. These pricing models may require assumptions or judgments in estimating fair values.

Consequently, the use of a different model or of different assumptions or judgments in applying a particular model may have produced different financial results for a particular period. See note 36 for a derivative sensitivity analysis in relation to energy prices and interest rates.

(b) Impairment of Long-Term Assets

Impairment tests are performed whenever there is an indication that the recoverable amount of property, plant, equipment, and intangible assets with definite lives are less than the corresponding net book value of assets.

Considering that estimated recoverable amounts related to PP&E and intangible assets are based on the best information available, changes in the estimates and judgments could change the impairment test results, which could affect the Company's results. See note 13 regarding asset impairments.

(c) *Income Taxes*

The Company is subject to income taxes in numerous jurisdictions. Significant interpretations and estimates are required in determining the total amount of income taxes. The Company considers the recoverability of the tax assets existing at December 31, 2014 and 2013, to determine the tax assets to recognize.

There are many transactions and calculations for which the ultimate tax determination is uncertain during the ordinary course of business. Different interpretations and estimates would result in a different level of income taxes, current and deferred, recognized in the period.

(d) *Dismantling and Decommissioning Provisions*

The Company has a contractual obligation to remove its wind electricity generation equipment (note 2(k)). The Company estimates the current day cost of the equipment removal and then calculates the current present value of the obligation by applying an inflation rate to the end of the asset's useful life and discounting back to current day amounts using an interest rate.

The use of assumptions in estimates and judgments different than referred to above may have produced different results from those that have been considered.

(e) *Useful Life of Property, Plant, and Equipment*

The Company recognizes depreciation expense pro rata over the estimated useful lives of its assets. The use of useful lives different than referred to above may have produced different results from those that have been considered.

(f) *Joint Ventures*

The Company utilizes judgment in determining if it has joint control of certain associates. Different results of this analysis may result in the consolidation of these associates.

(4) Financial Risk Management Policies

(a) *Financial Risk Management*

The Company has exposure to a variety of risks resulting from its use of financial instruments, including credit risk and liquidity risk.

EDPR, as sole member, is responsible for the definition of general risk management principles and the establishment of exposure limits.

All transactions that utilize derivative instruments are directly approved by the EDPR management team through approval of the Company's commercial plan or by the approval of specific transactions. The approval process defines the parameters of each transaction and approves the formal documents describing the objectives.

(b) Counterparty Credit Risk

Counterparty risk is managed by an analysis of certain factors, including the technical capacity, competitiveness, credit rating, and exposure to each counterparty. Counterparties in derivatives and financial transactions are restricted to high-quality credit institutions.

The Company believes that the amount that best represents the Company's exposure to credit risk corresponds to the carrying amount of trade receivables and debtors, derivative instruments, and other assets.

The Company believes that the credit quality of amounts receivable from power sales is adequate and that no significant impaired receivables exist. The Company's customers largely consist of regulated utilities and regional power market operators. The Company has not experienced any material losses related to uncollectible receivables.

The Company's derivative instruments are obtained and settled through regulated exchanges. The Company has not experienced any material losses related to the credit risk of these exchanges

(c) Liquidity Risk

The Company is dependent on its Parent, EDPR, for construction activity liquidity needs. Liquidity risk is the possibility that EDPR will not be able to provide sufficient liquidity to meet the Company's needs. EDPR's strategy is to manage liquidity as to insure that it will always have significant liquidity to meet its liabilities when due, upon normal and stressed conditions, without incurring unacceptable losses or risking damage to the financial position. See note 29 for the maturity schedule of financial debt.

(d) Market Risk

Certain of the Company's facilities have entered into long-term power purchase agreements where ranging from a portion to all of the facility output is sold at established prices. At certain facilities that do not have long-term power purchase agreements, the Company is exposed to market risk related to the sale of electricity at then current market prices. The Company utilizes derivative instruments to manage a portion of these market risks. The Company seeks to apply hedge accounting for these derivatives in order to mitigate the impact of these instruments in profit or loss. As of December 31, 2014 and 2013, not all derivative instruments were qualified for hedge accounting. See notes 33 and 36 for further information. Although the Company was unable to qualify all derivative instruments for hedge accounting, it still believes that these instruments reduce the market risk exposure related to spot market energy prices.

(e) Capital Management

Management of the Company's capital is the responsibility of EDPR. The goal of EDPR in managing equity is to safeguard the Company's capacity to continue operating as a going concern, grow steadily to meet established growth targets, and maintain an optimum equity structure to reduce equity cost.

(5) Generating Revenue

Revenue is analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Electricity sales	$	467,920	440,207
Curtailment revenue		2,300	6,656
Renewable energy credit sales		40,707	26,383
	$	510,927	473,246

(6) Income Recognized from Sale of Interests in Institutional Equity Partnerships

The Company utilizes institutional equity partnerships to allow the Company to fully realize the value of the tax benefits available to companies involved in renewable energy production. The two primary tax benefits are the Company's choice of Production Tax Credits (PTCs) or the U.S. Department of Treasury (the Treasury) cash grant (see note 14 for further discussion), and accelerated depreciation (see note 27 for further discussion). EDPR NA records the proceeds from the sale of nonparticipatory interests in these partnerships as a noncurrent liability. Each period, EDPR NA determines the value of the tax benefits provided to the institutional investors and recognizes to Institutional Equity Partnership Income in accordance with note 27 and below.

Income type	Income recognition criteria
Production tax credits	Income recognized in the period the associated energy is generated
Tax loss benefit income	Income recognized over the useful lives of the underlying projects
Cash grant income	Income recognized over the useful lives of the underlying projects
Investment tax credit (ITC) income	Income recognized over the useful lives of the underlying projects
Residual minority interest accretion	Contra income recognized over the expected duration until the flip date
Other credits and payments	Income recognized upon delivery of credit or payment

Income recognized from sale of equity interests in institutional equity partnerships (Institutional Equity Partnership Income) is analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Total income by benefit type:			
Production tax credits	$	152,668	149,235
Tax loss benefit income		16,440	16,850
Cash grant income		11,127	11,060
Investment tax credit (ITC) income		19	—
Residual minority interest accretion		(11,975)	(12,303)
Other credits and payments		(4,076)	1,303
	$	164,203	166,145

During 2014, the Company obtained information that certain of its institutional investors are not able to claim all of the credits generated by the Company on their New York state tax returns previously recognized as other credits and payments. The Company increased its liabilities arising from institutional equity partnerships and reduced other credits and payments income above by $4.9 million for the year ended December 31, 2014.

(7) Other Income

Other income comprises the following:

		2014	2013
		(U.S. dollars in thousands)	
Royalty income – Wild Horse project	$	2,075	2,113
Turbine availability		611	5,074
Management fees – third parties		156	156
Management fees – related party		2,552	1,860
Gain on involuntary conversion of PP&E (note 19)		1,286	1,002
Business interruption insurance proceeds		—	557
Restructuring of power sales contract proceeds		—	14,036
Damages from construction delay		903	—
Transmission provider settlement		1,209	—
Other income		741	879
	$	9,533	25,677

The Company sold its interest in the Wild Horse wind farm project in 2006. As a component of the compensation for the sale, the Company received the right to receive a production-based royalty over the ensuing 15 years.

Turbine availability income is related to liquidated damages owed by turbine operations and maintenance providers resulting from guaranteed turbine availability targets that were not achieved.

Management fees – related party are management, development, and construction service related fees the Company charges its affiliated entity, EDP Renewables Canada LP (EDPR Canada), which is also wholly owned by EDPR. The Company's employees provide the majority of the support for EDPR Canada's activities, which include developing, constructing, and operating wind-powered electricity generating facilities in Canada.

Business interruption insurance income relates to recoveries under insurance policies the Company has in place to compensate the Company when insurable events cause a facility or portion of a facility to be unable to operate for extended periods of time.

Restructuring of power sales contract income relates to the approximate $14 million received for the reduction of the quantity of energy to be sold under one of the Company's power sales contracts.

Damages from construction delay income relates to amounts owed from a construction contractor for lost income as a result of not completing the construction of certain facilities by certain dates.

Transmission provider settlement income is compensation for a transmission provider wrongly curtailing one of Company's facilities in 2011.

(8) Supplies and Services

This balance comprises the following:

		2014	2013
		(U.S. dollars in thousands)	
Supplies and services:			
Maintenance and repairs	$	81,315	80,676
Leases and rents		25,910	26,292
Professional services		13,470	12,831
Insurance		7,926	8,101
Other supplies and services		1,229	1,674
Tools and office materials		1,153	1,177
Travel and entertainment		2,239	2,608
Cost of consumed electricity		1,977	1,720
Transmission costs		8,170	7,829
Communications		956	1,190
Commissions and fees		287	379
Utilities		1,547	1,381
EDPR management fee		5,316	6,169
Cost of RECs and power purchased		713	1,168
Turbine performance upgrade fees		183	315
Community and employee relations		1,129	1,132
	$	153,520	154,642

(9) Personnel Costs and Employee Benefits Expense

Personnel costs comprise the following:

		2014	2013
		(U.S. dollars in thousands)	
Employees' remuneration	$	31,971	30,415
Payroll taxes		2,765	2,626
Employees' bonus		8,102	5,911
Other costs		44	119
Own work capitalized		(11,398)	(7,250)
	$	31,484	31,821

The amount of own work capitalized represents labor expended for capitalized projects. This is reported on the consolidated statements of cash flows as a component of cash flows from investing activities. Own work capitalized increased in 2014 due to an increase in the Company's facility development and construction activities.

The breakdown of personnel and category of permanent staff as of December 31, 2014 and 2013 is as follows:

	2014	2013
Board members and senior officers	32	31
Senior management	118	36
Middle management		83
Highly skilled and skilled workers	118	117
Semiskilled workers	33	29
Subtotal permanent employees	301	296
Temporary employees	12	6
Total employees	313	302

Employee benefits expense comprises the following:

	2014	2013
	(U.S. dollars in thousands)	
Defined-contribution retirement plan (see note 2(j))	$ 2,034	1,909
Employee benefits	4,439	4,087
	$ 6,473	5,996

Employee benefits is primarily comprised of group insurance coverages provided to the employees.

(10) Other Expenses

Other expenses comprise the following:

		2014	2013
		(U.S. dollars in thousands)	
Direct operating taxes	$	23,825	22,445
Losses on involuntary conversions (note 19)		1,468	—
Losses on sales of fixed assets (note 19)		—	54
Donations		706	363
Loss on project abandonments (note 19)		489	5,370
Professional fees and association dues		825	986
Turbine availability expense		4,268	4,350
Permit compliance costs		1,159	999
Output guarantee expense		1,714	13,286
Other costs		1,668	1,958
Total	$	36,122	49,811

Direct operating taxes primarily relate to state and local ad valorem taxes on operating facilities.

The loss on project abandonments represents the write-off of previously capitalized costs related to wind farm development on projects that are no longer being pursued. See note 19 for further discussion.

Turbine availability expense is related to a bonus payable to turbine operations and maintenance providers resulting from exceeding established turbine availability targets.

Output guarantee expense relates to an agreement with a third party investor in one of the Company's subsidiaries whereby the Company guaranteed levels of facility output from the facilities in the portfolio from October 1, 2012 through September 30, 2016, and is to compensate for any shortfall. A payment is to be made based on actual performance through September 30, 2014 and a second payment after the remaining term in 2016. See notes 30 and 34 for further information.

(11) Provisions Expense

Provisions comprise the following:

		2014	2013
		(U.S. dollars in thousands)	
Avian regulation violation	$	—	1,000
Commercial litigation – long term		—	250
Commercial litigation – short term		—	300
	$	—	1,550

See note 28 for further information regarding provisions.

(12) Depreciation and Amortization Expense

This balance is analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Property, plant, and equipment:			
Plant and machinery	$	259,740	256,969
Office equipment and tools		7,338	6,203
Buildings and other constructions		481	1,417
Transport equipment		347	426
Other		611	832
		268,517	265,847
Intangible assets:			
Contract rights		1,197	1,133
	$	269,714	266,980

See note 19 for the asset values of the PP&E categories.

See note 20 for the asset values and amortization periods for the contract rights.

(13) Impairment of Tangible and Intangible Assets

Impairment of tangible and intangible assets comprises the following:

		2014	2013
		(U.S. dollars in thousands)	
Capitalized interest writeoff (note 19)	$	—	1,053
Total	$	—	1,053

(14) Amortization of Deferred Income

Amortization of deferred income comprises the following:

		2014	2013
		(U.S. dollars in thousands)	
Other deferred income – state (note 31)	$	586	586
Deferred income – U.S. Treasury cash grant (note 31)		22,509	22,490
Total	$	23,095	23,076

The American Recovery and Reinvestment Act of 2009, created a renewable energy grant program administered by the Treasury. The program expired in 2012. The grant program provided for the Treasury to provide grants for 30% of the eligible basis of qualifying energy property. Renewable energy generators had the option to apply for the aforementioned grant or receive PTCs over a 10-year period.

Amortization of deferred income results from cash grants received by entities not in institutional equity partnerships (note 27). As discussed in the accounting policies note 2(p), the grants, when received, are recorded as deferred revenue, and are recognized over the remaining useful life of the facility (note 31).

(15) Other Financial Income and Other Financial Expenses

Other financial income and other financial expenses are analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Other financial income:			
Derivative financial instruments	$	18,231	10,993
Interest income		814	463
Foreign exchange differences		53	78
Other		23	383
		19,121	11,917
Other financial expenses:			
Interest expense, net of capitalization (note 19)		71,180	78,265
Banking services		263	380
Unfavorable foreign exchange differences		167	145
Derivative financial instruments		13,432	9,549
Credit support services		5,804	5,650
Other financial losses		6,005	4,813
		96,851	98,802
Financial expenses	$	(77,730)	(86,885)

Guarantee fees charged by EDP of $1.5 million and $0.9 million were recorded in other financial losses for the years ended December 31, 2014 and 2013, respectively. Refer to note 35 for further information regarding these fees.

(16) Share in Gain (Loss) of Associates

Share of gain (loss) in associates comprises the following:

		December 31	
		2014	2013
		(U.S. dollars in thousands)	
Flat Rock Wind Power, LLC (Flat Rock I)	$	6,011	1,288
Flat Rock Wind Power II, LLC (Flat Rock II)		99	(1,497)
Blue Canyon Windpower LLC (note 40)		—	—
Total	$	6,110	(209)

The Company has investments in associates (note 21) that comprise 50% interests in Flat Rock I and Flat Rock II, which own and operate the Maple Ridge I and II wind farms in New York, respectively. Summarized profit and loss financial information for the Flat Rock affiliates is as follows:

		Year ended December 31	
		2014	**2013**
		(U.S. dollars in thousands)	
Results of operations:			
Operating revenues	$	53,446	41,361
Operating expense		(40,328)	(38,453)
Operating income		13,118	2,908
Interest income (expense)		5	(6)
Net income	$	13,123	2,902
Adjustments to prior year financials after issuance		(779)	—
Adjusted net income	$	12,344	2,902

Adjustments to prior year financials after issuance relate to adjustments made by the affiliate to their 2013 financials after the Company issued its 2013 financial statements. The Company recognized the earnings difference in 2014.

The difference between the Company's share in the affiliates' net loss and the balance in share in loss of affiliates is summarized as follows:

		Year ended December 31	
		2014	**2013**
		(U.S. dollars in thousands)	
Affiliates' net income	$	12,344	2,902
EDPR NA timing difference		—	(735)
Depreciation and accretion expense difference (note 21)		722	(1,741)
Adjusted net income		13,066	426
Share in income – 50%		6,533	213
Amortization of fair market increase (prior to adoption of IFRS) (note 21)		(423)	(422)
Share in loss of associates	$	6,110	(209)

EDPR NA timing difference relates to an estimate recorded in 2012 before the issuance of the 2012 Flat Rock financials and reversed in 2013 upon new information provided in 2013.

As the investment in Blue Canyon Windpower LLC has been reduced to $0, no further losses are recorded. See note 40 for further discussion.

(17) Income Tax Expense

Under the terms of the institutional equity partnerships, substantially all of the taxable income and production tax credits generated by these partnerships accrue to the benefit of the third-party investors.

The income tax provision is analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Current tax (benefit):			
Current year	$	(4,640)	—
Changes in estimate for prior years		—	—
Total current tax (benefit)		(4,640)	—
Deferred tax (benefit):			
Origination and reversal of temporary differences		20,663	(286)
Changes in state tax law and other		(17,283)	(5,852)
Change in tax rate		—	(5,224)
Change in state net operating losses		12,323	3
Total deferred benefit		15,703	(11,359)
Net expense (benefit)	$	11,063	(11,359)

The reconciliation between the statutory income tax and the effective income tax rate is analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Income per consolidated statements of income	$	127,762	100,556
Net tax benefit		11,063	(11,359)
Income excluding tax	$	138,825	89,197

	2014		2013	
	Rate percentage	Tax	Rate percentage	Tax
	(U.S. dollars in thousands)			
Tax using the Company's domestic tax rate	38.21%	$ 53,052	38.21%	$ 34,086
Impact of U.S. Treasury cash grant	(2.94)	(4,083)	(4.67)	(4,162)
Tax basis goodwill	(10.73)	(14,900)	(16.70)	(14,900)
Other permanent differences	(1.22)	(1,690)	(2.47)	(2,202)
Taxes related to noncontrolling interest	(8.63)	(11,981)	(10.80)	(9,633)
Tax credits	(0.60)	(839)	(2.19)	(1,956)
Change in tax rate	0.85	1,179	(5.86)	(5,224)
State income taxes	(2.07)	(2,867)	—	—
Change in recognized deductible temporary differences	(4.90)	(6,808)	(8.26)	(7,368)
Total	7.97%	$ 11,063	(12.74)%	$ (11,359)

Tax expense (benefit) recognized directly in equity is analyzed as follows:

	2014	2013
	(U.S. dollars in thousands)	
Derivative financial instruments	$ 2,710	532
Result of sale of noncontrolling interest	—	264
	$ 2,710	796

(18) Deferred Tax Assets and Liabilities

Unrecognized Deferred Tax Assets and Liabilities

Unrecognized deferred tax assets and liabilities are analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Charitable contribution carryovers			
Beginning balance	$	838	835
Contributions made		183	102
Expired contributions		(44)	(99)
Ending balance		977	838
State tax NOLs			
Beginning balance		—	—
State tax NOLs		12,184	—
Adjustments to state tax NOLs		—	—
Ending balance		12,184	—
Total unrecognized deferred tax assets and liabilities	$	13,161	838

All deferred tax assets and liabilities were recognized, with the exception of $13,161 thousand and $838 thousand for the years ended December 31, 2014 and 2013, respectively. These unrecognized deferred tax assets are related to charitable contribution carryovers and state tax NOLs that will expire before the Company can utilize them.

Recognized Deferred Tax Assets and Liabilities

	Assets		Liabilities		Net	
	2014	2013	2014	2013	2014	2013
			(U.S. dollars in thousands)			
Federal tax loss carryforward	$ 885,013	818,236	—	—	885,013	818,236
State tax loss carryforward	88,870	64,960	—	—	88,870	64,960
Tax credit carryforward	34,119	33,280	—	—	34,119	33,280
Hire Act credit carryforward	18	18	—	—	18	18
R&D credit carryforward	1,520	1,520	—	—	1,520	1,520
Bonus expense	3,101	2,868	—	—	3,101	2,868
Derivative financial instruments	—	1,601	(3,142)	—	(3,142)	1,601
Intangible assets and other	—	—	(27,663)	(17,395)	(27,663)	(17,395)
Property, plant, and equipment	—	—	(442,795)	(414,914)	(442,795)	(414,914)
Income received from institutional partnerships	—	—	(488,630)	(421,350)	(488,630)	(421,350)
Tax assets (liabilities)	1,012,641	922,483	(962,230)	(853,659)	50,411	68,824
Setoff of tax	(962,230)	(853,659)	962,230	853,659	—	—
Net tax assets	$ 50,411	68,824	—	—	50,411	68,824

Deferred tax assets will be utilized to offset taxable income that is projected to be generated in future periods.

The Company utilizes institutional equity partnerships (note 27) to better utilize available tax benefits. These partnerships allocate the majority of tax losses generated by certain facilities to the institutional investors rather than the Company. Under U.S. income tax law, the majority of renewable facility assets are depreciated within the first 5 years from being placed in service versus 25 years for financial statement purposes. These depreciation differences create deferred tax liabilities for the Company.

The movement in deferred taxes during the year is as follows:

	January 1, 2013	Recognized in income	Recognized in other comprehensive income	December 31, 2013	Recognized in income	Recognized in other comprehensive income	December 31, 2014
	(U.S. dollars in thousands)						
Federal tax loss carryforward	$ 725,631	92,605	—	818,236	66,777	—	885,013
State tax loss carryforward	43,012	21,948	—	64,960	23,910	—	88,870
Tax credit carryforward	32,470	810	—	33,280	839	—	34,119
Hire Act credit carryforward	18	—	—	18	—	—	18
R&D credit carryforward	—	1,520	—	1,520	—	—	1,520
Bonus expense	3,109	(241)	—	2,868	233	—	3,101
Derivative financial instruments	(308)	2,441	(532)	1,601	(2,033)	(2,710)	(3,142)
Intangible assets and other	2,281	(19,676)	—	(17,395)	(10,268)	—	(27,663)
Property, plant, and equipment	(378,410)	(36,504)	—	(414,914)	(27,881)	—	(442,795)
Income received from institutional partnerships	(369,542)	(51,544)	(264)	(421,350)	(67,280)	—	(488,630)
Net tax assets	$ 58,261	11,359	(796)	68,824	(15,703)	(2,710)	50,411

(19) Property, Plant, and Equipment

This balance is analyzed as follows:

	2014	2013
	(U.S. dollars in thousands)	
Cost:		
Plant and machinery	$ 7,112,232	6,674,553
Land	12,853	12,583
Buildings and other constructions	10,791	10,644
Transport equipment	3,186	2,665
Office equipment and tools	41,559	34,842
Other	5,121	4,972
Assets under construction	658,740	401,432
	7,844,482	7,141,691

		2014	2013
		(U.S. dollars in thousands)	
Accumulated depreciation:			
Depreciation charge for the period	$	(268,517)	(265,847)
Accumulated depreciation in previous years		(1,328,931)	(1,063,446)
Accumulated depreciation on assets disposed		887	362
		(1,596,561)	(1,328,931)
Carrying amount	$	6,247,921	5,812,760

The movement in PP&E for the year of 2014 is analyzed as follows:

		Balance, January 1	Acquisition	Disposals	Impairment	Transfers	Balance, December 31
				(U.S. dollars in thousands)			
Cost:							
Plant and machinery	$	6,674,553	25,398	(3,173)	—	415,454	7,112,232
Land and natural resources		12,583	270	—	—	—	12,853
Buildings and other constructions		10,644	147	—	—	—	10,791
Transport equipment		2,665	521	—	—	—	3,186
Office equipment and tools		34,842	761	—	—	5,956	41,559
Other		4,972	138	—	—	11	5,121
Assets under construction		401,432	679,218	(489)	—	(421,421)	658,740
	$	7,141,691	706,453	(3,662)	—	—	7,844,482

Included in the PP&E balance as of December 31, 2014 are $567 million of supplier invoices, construction and other PP&E-related accruals (notes 30), which have been excluded from the 2014 consolidated statement of cash flows.

In 2014, the Company abandoned projects of $489 thousand identified as no longer attractive for execution. These amounts were removed from assets under construction and recorded to other operating expenses. See note 10 for further discussion.

During 2014, one of the Company's operating facilities suffered a casualty loss, which resulted in the disposal of $1.3 million of PP&E net of $0.5 million of accumulated depreciation. The $2.1 million replacement cost of this equipment is recorded as a component of insurance recovery receivable (note 24). The Company recognized a gain on involuntary conversion of $1.3 million (note 7).

During 2014, three of the Company's operating facilities suffered casualty losses, which resulted in the disposal of $1.9 million of PP&E net of $0.4 million of accumulated depreciation. The Company recognized losses on involuntary conversions of $1.5 million (note 10).

		Balance, January 1	Charge for the period	Disposals	Impairment	Transfers	Balance, December 31
				(U.S. dollars in thousands)			
Accumulated depreciation:							
Plant and machinery	$	1,292,364	259,740	(887)	—	—	1,551,217
Buildings and other constructions		7,380	481	—	—	—	7,861
Transport equipment		1,931	347	—	—	—	2,278
Office equipment and tools		23,247	7,338	—	—	—	30,585
Other		4,009	611	—	—	—	4,620
	$	1,328,931	268,517	(887)	—	—	1,596,561

The movement in PP&E for the year of 2013 is analyzed as follows:

		Balance, January 1	Acquisition	Disposals	Impairment	Transfers	Balance, December 31
				(U.S. dollars in thousands)			
Cost:							
Plant and machinery	$	6,662,011	4,906	(1,250)	—	8,886	6,674,553
Land and natural resources		5,767	7,408	(591)	—	(1)	12,583
Buildings and other constructions		10,641	3	—	—	—	10,644
Transport equipment		2,334	331	—	—	—	2,665
Office equipment and tools		41,417	1,398	(792)	—	(7,181)	34,842
Other		4,466	254	—	—	252	4,972
Assets under construction		261,873	157,037	(6,398)	(1,053)	(10,027)	401,432
	$	6,988,509	171,337	(9,031)	(1,053)	(8,071)	7,141,691

Included in the PP&E balance as of December 31, 2013 are $67.4 million of supplier invoices, construction and other PP&E-related accruals (note 30), which have been excluded from the 2013 consolidated statement of cash flows.

In 2013, the Company abandoned projects of $5.4 million identified as no longer attractive for execution. These amounts were removed from assets under construction and recorded to other operating expenses. See note 10 for further discussion.

During 2013, one of the Company's operating facilities suffered a casualty loss, which resulted in the disposal of $1.3 million of PP&E net of $0.4 million of accumulated depreciation. The $1.9 million replacement cost of this equipment is recorded as a component of insurance recovery receivable (note 24). The Company recognized a gain on involuntary conversion of $1 million (note 7).

During 2013, the Company sold land and development assets of $1.62 million in exchange for $1.56 million in cash. The Company recorded a loss on sales of fixed assets of $54 thousand (note 10) for the year ended December 31, 2013.

During 2013, an equipment supply contract, for which approximately $47 million of prepayments were made in prior years, was cancelled. The supplier returned $35 million in cash, which is reflected in the table above as a reduction in acquisitions, and provided $4 million in other equipment. The remaining $8.1 million minus $1.2 million realized in 2013 will be repaid through credits applied through 2015 to their existing operations and maintenance service agreements. This amount was reclassified as advances to maintenance service providers (note 24), which is reflected as a transfer in the table above. Borrowing costs associated with these expenditures were capitalized as a component of property, plant, and equipment, and are no longer considered recoverable after the contract's cancellation. The Company recognized a loss on impairment for the associated borrowing costs of approximately $1 million in the consolidated statement of income for the year ended December 31, 2013 (note 13).

See note 13 for additional information regarding impairments.

	Balance, January 1	Charge for the period	Disposals	Impairment	Transfers	Balance, December 31
			(U.S. dollars in thousands)			
Accumulated depreciation:						
Plant and machinery	$ 1,033,771	256,969	(362)	—	1,986	1,292,364
Buildings and other constructions	5,963	1,417	—	—	—	7,380
Transport equipment	1,505	426	—	—	—	1,931
Office equipment and tools	19,030	6,203	—	—	(1,986)	23,247
Other	3,177	832	—	—	—	4,009
	$ 1,063,446	265,847	(362)	—	—	1,328,931

(a) *Capitalized Interest*

Capitalized interest expense relates to borrowing costs directly associated with the acquisition and construction of electrical generating facilities and is recorded as a component of PP&E. The Company has a cumulative capitalized interest of $109 million and $104 million as of December 31, 2014 and 2013, respectively. The Company capitalized 6.29% and 6.7% of its interest costs for the years ended December 31, 2014 and 2013, respectively.

(b) *Capitalized Labor*

The Company has capitalized labor as a component of PP&E. The Company has cumulative capitalized labor of $101 million and $90 million as of December 31, 2014 and 2013, respectively.

(20) Intangible Assets

Intangible assets comprise a royalty instrument, substation access rights, and power sales contracts that have a net book value of $94 million and $89 million as of December 31, 2014 and 2013, respectively.

The Wild Horse royalty instrument relates to the fair value assigned to a wind farm royalty stream under contract upon the Company's acquisition by the Goldman Sachs Group in 2005. This instrument is amortized in the periods for which the discounted cash flows used to value the contract right pertain. The instrument will be fully amortized at the end of 2026, with the expiration of the royalty agreement.

Substation access rights relate to costs incurred in accordance with transmission services agreements that are necessary for the Company to deliver power to market. These rights are amortized to depreciation and amortization expense using the straight-line method over the useful life (note 2(e)) of the facility to which the right belongs.

Power sales contracts relate to the value of contracts acquired during asset purchases. These values will be amortized using the straight-line method over the term of the power sales contracts.

The movement in intangible assets for the year of 2014 is analyzed as follows:

	Balance, January 1	Acquisitions	Disposals	Transfers	Balance, December 31
			(U.S. dollars in thousands)		
Cost:					
Wild Horse royalty instrument	$ 6,013	—	—	—	6,013
Substation access rights	26,090	6,017	—	—	32,107
Power sales contracts	62,814	—	—	—	62,814
	$ 94,917	6,017	—	—	100,934

None of the intangible assets acquired during 2014 have been placed in service. Amortization expense will be recognized when the equipment is placed in service or contracts commence.

	Balance, January 1	Charge for the year	Disposals	Transfers	Balance, December 31
			(U.S. dollars in thousands)		
Accumulated amortization and impairment losses:					
Wild Horse royalty instrument	$ 3,439	330	—	—	3,769
Substation access rights	2,439	867	—	—	3,306
	$ 5,878	1,197	—	—	7,075

The movement in intangible assets for the year of 2013 is analyzed as follows:

	Balance, January 1	Acquisitions	Disposals	Transfers	Balance, December 31
			(U.S. dollars in thousands)		
Cost:					
Wild Horse royalty instrument	$ 6,013	—	—	—	6,013
Substation access rights	20,007	6,083	—	—	26,090
Power sales contracts	—	62,814	—	—	62,814
	$ 26,020	68,897	—	—	94,917

None of the intangible assets acquired during 2013 have been placed in service. Amortization expense will be recognized when the equipment is placed in service or contracts commence.

Included in the power sales contracts balance as of December 31, 2013 is a $38.3 million supplier invoice (note 30), which has been excluded from the 2013 consolidated statement of cash flows.

		Balance, January 1	Charge for the year	Disposals	Transfers	Balance, December 31
			(U.S. dollars in thousands)			
Accumulated amortization and impairment losses:						
Wild Horse royalty instrument	$	3,077	362	—	—	3,439
Substation access rights		1,668	771	—	—	2,439
	$	4,745	1,133	—	—	5,878

(21) Investment in associates

The Company's investments in associates comprise the following:

		December 31 2014	December 31 2013
		(Dollars in thousands)	
Flat Rock I	$	128,383	137,896
Flat Rock II		53,117	56,755
Total	$	181,500	194,651

The Company's investments in associates of $182 million and $195 million as of December 31, 2014 and 2013, respectively, comprise of 50% interests in Flat Rock I and Flat Rock II, which own and operate the Maple Ridge I and II wind farms in New York. These associates operate under the terms of agreements with an unrelated third party that holds the remaining 50% interest in these entities. Under these agreements, the Company is entitled to its share of the net assets of the associates'. The Company is not exposed to the liabilities of the associates and has no obligation to provide any additional investment to the associated entities. Summarized financial information for the Flat Rock affiliates is as follows:

		December 31	
		2014	**2013**
		(Dollars in thousands)	
Financial position:			
Current assets	$	6,388	10,968
Property, plant, and equipment, net		352,331	373,115
Intangibles		4,814	5,135
Total assets	$	363,533	389,218
Current liabilities	$	420	336
Asset retirement obligation		5,320	4,913
Members' equity		357,793	383,969
Total liabilities and members' equity	$	363,533	389,218

The following summarizes the status and results of the Company's investments in associates:

		December 31	
		2014	**2013**
		(Dollars in thousands)	
Beginning investment in unconsolidated affiliates	$	194,651	203,846
Adjusted share in income (loss) (note 16)		6,533	213
Distributions from associates		(19,261)	(8,986)
Amortization of fair market increase (on EDP acquisition)		(423)	(422)
Ending investment in unconsolidated affiliates	$	181,500	194,651

The difference between the Company's equity share in the affiliates' net assets and the balances in the Company's equity investments in the affiliates is summarized as follows:

		December 31	
		2014	2013
		(Dollars in thousands)	
Affiliates' net assets (members' equity)	$	357,793	383,969
Accumulated depreciation and accretion expense difference		(8,812)	(9,534)
Adjusted affiliates' net assets (members' equity)		348,981	374,435
Underlying equity in net assets (members' equity) – 50%		174,491	187,219
Gross purchase price allocation		10,698	10,698
Accumulated amortization of purchase price allocation		(3,689)	(3,266)
Investment in associates		181,500	194,651

The depreciation and accretion expense difference relates to a difference in wind farm useful lives, dismantling assumptions, and salvage values used by the affiliate and the Company. The Company began recording the differences in useful lives in equity in loss during the year ended December 31, 2010.

The purchase price allocation difference comprises of fair value increases prior to the Company's adoption of IFRS on January 1, 2006.

(22) Inventories

Inventories are analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Spare parts inventory	$	4,200	3,023
	$	4,200	3,023

(23) Trade Receivables

Trade receivables are analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Trade receivables – current:			
Utility customers	$	50,961	49,263
Damages from construction delay (note 7)		903	—
Turbine maintenance service providers – turbine availability income		862	5,335
	$	52,726	54,598

(24) Debtors and Other Assets

Debtors and other assets are analyzed as follows:

		December 31	
		2014	2013
		(U.S. dollars in thousands)	
Noncurrent:			
Notes receivable	$	5,022	6,082
Deferred amortizable costs		7,956	8,647
Advances to maintenance service providers (note 19)		789	2,971
Warranty claim receivable		—	1,082
Other amortizable costs		1,255	2,510
	$	15,022	21,292

		December 31	
		2014	2013
		(U.S. dollars in thousands)	
Current:			
Loans to affiliates	$	3,415	2,722
Restricted cash		9,321	12,900
Prepaid insurance		3,294	2,954
Warranty claim receivable		737	737
Notes receivable		1,331	1,331
Prepaid costs		8,965	8,139
Advances to maintenance service providers (note 19)		2,182	3,950
Availability income receivable (note 7)		848	949
Insurance recovery receivable		8,184	2,955
Unsold RECs and state PTCs		3,586	10,028
State income tax receivable		4,640	—
Other receivables		7,882	8,446
	$	54,385	55,111

The warranty claim receivable relates to a claim made against the manufacturer of certain equipment that was determined to be defective. Under a settlement agreement reached in 2010, the manufacturer will reimburse EDPR NA in five equal annual installments of $737 thousand.

Notes receivable relates to amounts owed from transmission providers for network upgrade costs paid by the Company to the transmission providers in accordance with transmission services operating agreements. The transmission providers will make repayments by providing credits against their transmission services provided. The notes do not have a fixed repayment schedule. Interest receivables represent accrued interest income from these notes.

Unsold RECs and state PTCs relate to credits generated at certain facilities where firm contracts have not been executed for their sale. Unsold RECs are recorded at current net realizable value as other deferred income in current trade and other payables (note 30). Upon the execution of a firm sales contract that quantity of RECs or state PTCs will be recognized to revenue as renewable energy credit sales (note 5). See paragraph immediately below for a change in regulation of state PTCs.

State income tax receivable relates to state tax refunds from the state of Oklahoma. Commencing in 2014, the state banned the sale of state PTCs to third parties, but will allow the producers of the credits to claim a refund of 85% of the PTC on their state tax return, and receive cash if the credit value exceeds their tax liability (note 17).

(25) Cash

Cash is analyzed as follows:

		December 31	
		2014	2013
		(U.S. dollars in thousands)	
Cash:			
Cash in hand	$	—	1
Bank deposits:			
Current deposits		96,048	47,050
Specific demand deposits in relation to Institutional Partnerships		95,737	85
Cash	$	191,785	47,136

Specific demand deposits in relation to Institutional Equity Partnerships are funds required to be held in escrow sufficient to pay the remaining construction related costs of projects in institutional equity partnerships (note 27). The governing agreements of these partnerships and specific escrow agreements define the appropriate expenditure of these funds.

(26) Noncontrolling interest

Noncontrolling interest is analyzed as follows:

		December 31	
		2014	2013
		(U.S. dollars in thousands)	
Noncontrolling interest:			
Balance as of January 1	$	215,563	177,681
Sale of noncontrolling interest		—	46,466
Distributions		(38,150)	(34,115)
Noncontrolling interest share of net income		31,351	25,531
Balance as of December 31	$	208,764	215,563

During 2013, the sale of noncontrolling interest relates to the Company selling 49% of its interest in Wheat Field Holding LLC (Wheat Field) to a third party for $48.4 million. Wheat Field owns and operates a 97 MW wind-powered electrical generating facility in Oregon. As a result of the sale, the third party is entitled to share in 49% of the residual value, income and loss, and cash generated thereon by Wheat Field from July 1, 2013. The Company recognized a gain from the sale net of taxes of $0.05 million, which is recorded in equity as the result of sale of noncontrolling interest, net of tax.

(Continued)

Result of sale of noncontrolling interest, net of tax is analyzed as follows:

		December 31	
		2014	**2013**
		(U.S. dollars in thousands)	
Noncontrolling interest, net of tax:			
Balance as of January 1	$	33,648	33,861
Sales proceeds		—	48,400
Carrying value of noncontrolling interest on date of sale		—	(46,466)
Transaction costs incurred		—	(1,883)
Deferred tax effect		—	(264)
Balance as of December 31	$	33,648	33,648

(27) Liabilities Arising from Institutional Equity Partnerships, Net of Transaction Costs

This balance is analyzed as follows:

		Balance, January 1, 2013	Movement	Balance, December 31, 2013	Movement	Balance, December 31, 2014
				(U.S. dollars in thousands)		
Proceeds from sale of equity partnership interests	$	2,575,743	—	2,575,743	291,325	2,867,068
Value of tax benefits provided		(1,456,054)	(134,886)	(1,590,940)	(115,793)	(1,706,733)
Cash distributions to institutional investors		(64,861)	(47,899)	(112,760)	(93,342)	(206,102)
Discount on proceeds		(3,053)	248	(2,805)	212	(2,593)
Cash grant benefit to institutional investors		(278,184)	—	(278,184)	—	(278,184)
ITC benefit to institutional investors		—	—	—	(25,255)	(25,255)
Interest on outstanding balance		438,062	78,272	516,334	71,604	587,938
Subtotal subject to interest		1,211,653	(104,265)	1,107,388	128,751	1,236,139
Noncurrent deferred revenue		722,023	(35,160)	686,863	(48,397)	638,466
Deferred income – cash grant		251,165	(11,060)	240,105	(11,127)	228,978
Deferred income – ITC		—	—	—	25,236	25,236
Liability for residual minority interest		46,137	12,303	58,440	11,975	70,415
Transaction costs		(14,710)	2,280	(12,430)	959	(11,471)
Balance at the end of year	$	2,216,268	(135,902)	2,080,366	107,397	2,187,763

In order to fully utilize the tax benefits available to companies involved in renewable energy generation, EDPR NA utilizes institutional equity partnership structures. Each structure involves a holding company to which certain of our renewable generation projects have been contributed.

EDPR NA, known as the Project Sponsor, has a relationship with the institutional investors established through a limited liability company operating agreement (the LLC agreement) that apportions the cash flows generated by the facilities between the investors and the Project Sponsor and allocates the tax benefits largely to the investor. The tax benefits primarily include the Company's choice of the ITC, which commenced in 2014, or PTCs and accelerated depreciation. Prior to 2012, the Company could elect a U.S. Treasury cash grant (note 14) structure.

The institutional investors purchase their partnership interests for an initial cash payment. If EDPR NA elects a PTC structure, this payment is sized so that the investors, as of the date that they purchase their interest, anticipate earning an agreed targeted internal rate of return by the end of the 10-year period over which PTCs are generated. This anticipated return is computed based on the total anticipated tax benefits that the institutional investors will receive, which includes the value of the PTCs, allocated taxable income or loss, and cash distributions, in addition to the return of their initial cash payment.

If EDPR NA elects an ITC structure, this payment is sized so that the investors, as of the date that they purchase their interest, anticipate receiving a fixed cash flow stream for five years, which is the accelerated tax depreciation period afforded to renewable energy generating assets. In addition to the cash flow stream, the investors will receive the value of the ITC and allocated taxable income or loss over the five-year period.

If EDPR NA elects a cash grant structure, this payment is sized so that the investors, as of the date that they purchase their interest, anticipated earning an agreed targeted internal rate of return during the accelerated tax depreciation period afforded to renewable energy generating assets. The anticipated return is computed based on the total anticipated benefits that the institutional investors will receive, which includes the value of the cash grant, allocated taxable income or loss, and cash distributions, in addition to the return of their initial cash payment.

Transaction costs include advisory and other professional fees directly related to the sale of the membership interests to the institutional investors. These fees are included in the consolidated statements of cash flows as payments for transaction costs related with institutional equity partnerships. The Company amortizes these costs on a straight-line basis through the flip date and are included as a component of other financial losses (note 15). The Company recognized amortization expense of $3.3 million and $2.3 million for the years ended December 31, 2014 and 2013, respectively.

Included above in cash distributions to institutional investors are the Company's 25% share of Blue Canyon I's distributions to institutional investors of $0.84 million and $0.65 million for the years ended December 31, 2014 and 2013, respectively. Blue Canyon I is not a consolidated subsidiary, and therefore, these amounts are not included in the accompanying consolidated statements of cash flows.

As of December 31, 2014, the Company has the following institutional equity partnerships:

Structure legal entity	Facility	Date created	Project Sponsor interest ownership percentage		Gross property, plant, and equipment	Institutional investor funding
					(U.S. dollars in thousands)	
PTC structures:						
Blue Canyon I	Blue Canyon I	December 2003	25%	$	20,844	16,308
2007 Vento I		July 2007	100		905,089	722,054
Flat Rock Windpower	Maple Ridge I (1)					
Flat Rock Windpower II	Maple Ridge II (1)					
Madison	Madison					
Blue Canyon II	Blue Canyon II					
Mesquite	Lone Star I					
High Trail	Twin Groves I					
2007 Vento II(3)		December 2007	51		1,096,261	600,743
Old Trail	Twin Groves II					
Telocaset	Elkhorn Valley					
High Prairie II	Prairie Star					
Post Oak (2)	Lone Star II					
2008 Vento III (7)		December 2008	100		1,154,742	509,222
Pioneer Prairie I	Pioneer Prairie I, II					
Arlington	Rattlesnake Road					
Cloud County	Meridian Way					
2009 Vento V (8)		December 2009	100		198,898	116,880
Blue Canyon V	Blue Canyon V					
2011 Vento X (4)		December 2011	100		160,574	97,493
Blue Canyon VI	Blue Canyon VI					
2014 Vento XI (5) (8)		December 2014	100		339,739	192,778
Headwaters	Headwaters					
2014 Vento XII (6) (8)		December 2014	100		180,995	66,220
Rising Tree I	Rising Tree I					
Rising Tree II	Rising Tree II					

Structure legal entity	Facility	Date created	Project Sponsor interest ownership percentage	Gross property, plant, and equipment	Institutional investor funding
				(U.S. dollars in thousands)	
ITC structure:					
2014 Sol I		August 2014	100	93,332	32,327
Lone Valley I	Lone Valley I				
Lone Valley II	Lone Valley II				
Cash grant structures:					
2009 Vento IV		August 2009	100	240,187	101,936
Rail Splitter	Rail Splitter				
2009 Vento VI		December 2009	100	203,860	90,899
Lost Lakes	Lost Lakes				
2010 Vento VII		September 2010	100	207,456	85,240
Meadow Lake II	Meadow Lake II				
2010 Vento VIII		December 2010	100	184,551	99,299
Sagebrush	Kittitas Valley				
2011 Vento IX (8)		July 2011	100	208,619	115,743
Paulding II	Timber Road II				

(1) EDPR NA's 50% interest.

(2) Post Oak was contributed in 2008 upon completion of construction.

(3) Prior to December 2012, the Company owned 100% of cash interest ownership until selling 49% to a third party (note 26).

(4) After the flip, date but no later than December 31, 2021, the institutional investors are to contribute $1 for every $1 of PTCs they are allocated. The accumulated contributions are not to exceed $48.7 million. Prior to reaching the earlier of December 31, 2021 or the contribution maximum, the institutional investors are allocated 99% of the PTCs.

(5) After the flip date but no later than December 31, 2024, the institutional investors are to contribute $1 for every $1 of PTCs they are allocated. The accumulated contributions are not to exceed $10 million. Prior to reaching the earlier of December 31, 2024 or the contribution maximum, the institutional investors are allocated 99% of the PTCs.

(6) As of December 31, 2014, not all of the Vento XII turbines were commissioned, and the amount above is a partial funding by the institutional investors. During January 2015, an additional $43.4 million was funded by the institutional investors.

After the flip, date but no later than December 31, 2024, the institutional investors are to contribute $1 for every $1 of PTCs they are allocated. Prior to reaching December 31, 2024, the institutional investors are allocated 99% of the PTCs.

(7) On August 19, 2014, the Company executed a membership interest purchase agreement to sell 25% of its Project Sponsor interest ownership to an unrelated third party. The sale received regulatory approval in 2015 and the Company transferred 25% of its Project Sponsor interest ownership to the third party in 2015 (note 38).

(8) On August 19, 2014, the Company executed a membership interest purchase agreement to sell 49% of its Project Sponsor interest ownership to an unrelated third party. The sale received regulatory approval in 2015 and the Company transferred 25% of its Project Sponsor interest ownership to the third party in 2015 (note 38).

The flip date occurs on the date the institutional investors for a particular structure have received the return of their cash investment plus the specified return using the rate of return defined in the LLC agreement, or a fixed date as defined by the LLC agreement if an ITC structure. The LLC agreements define the allocation of cash flows throughout the term of the structure. Before the flip date, allocations of operating cash flow may change at a point in time known as the cash flip date, as specified in the various LLC agreements.

The structure's cash flip dates and current cash allocations as of December 31, 2014 are defined as follows:

Structure	Cash flip date	Current cash allocation percentage		
		EDPR NA	Institutional investor	
Vento I	Original capital recovered or December 31, 2014	100%	—	
Vento II	Original capital recovered less $26 million or September 30, 2016	51	—	(i)
Vento III	July 6, 2014	—	100	
Vento IV	September 30, 2010	—	100	
Vento V	Capital account equals zero or flip date	40	60	
Vento VI	N/A	—	100	
Vento VII	March 31, 2014	—	100	
Vento VIII	April 30, 2014	—	100	
Vento IX	April 30, 2014	—	100	
Vento X	September 30, 2012	—	100	
Vento XI	Original capital recovered or October 31, 2022	100	—	
Vento XII	Various dates ranging from November 20, 2020 through May 31, 2021 based on the production levels of the facilities	100	—	
Sol I	December 24, 2019	100 minus (ii)	(ii)	

(i) Prior to December 2012, the Company owned 100% of the cash interest ownership until selling 49% to a third party (note 26).

(ii) The institutional investor is to receive $646 on an annual basis, which is 2% of their funding amount, paid in quarterly amounts of $162 thousand. EDPR NA will receive all cash distributions in excess of the above amount.

After the flip date, the institutional investor retains a small minority interest for the duration of its membership in the structure. The minority interest percentages range from 2.5% to 6%, except for 20% at Blue Canyon I. EDPR NA also has an option to purchase the institutional investor's residual interests at fair market value on the flip date for PTC structures and the later of the flip date or five years from turbine commissioning or ten years after funding if the flip date has not yet occurred for cash grant structures.

Prior to the flip date, 99% or more of the tax income and benefits generated by the partnerships are allocated to the institutional investor subject to any tax basis and capital account limitations, with any remaining benefits allocated to EDPR NA.

EDPR NA records the proceeds received from the sale of the interests in the partnerships as a noncurrent liability. This liability is reduced by the value of tax attributes provided and cash distributions made to the institutional investors during the period. The liability to the institutional investors is increased by an interest accrual that is a function of the outstanding liability balance and the targeted internal rate of return.

The values of certain of the tax attributes delivered, primarily the cash grant, ITC, and accelerated depreciation, are recorded as noncurrent deferred income and are recognized and reclassified to Institutional Partnership Income pro rata over the 25-year useful life of the underlying projects. Other tax benefits, such as PTCs, are recognized to Institutional Partnership Income when generated.

The liability for residual minority interest is accreted on a straight-line basis from the funding date through the flip date to reflect the institutional investors' minority interest position in the Company at the flip date. Residual interest accretion is recognized as a reduction to Institutional Partnership Income.

(28) Provisions for Liabilities and Charges

Provisions for liabilities and charges are analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Long-term provisions for liabilities and charges:			
Decommissioning obligations	$	59,992	49,833
Avian regulation violation		1,000	1,000
Commercial litigation		250	250
	$	61,242	51,083
Short-term provisions for liabilities and charges:			
Commercial litigation	$	110	110
	$	110	110

(Continued)

Decommissioning obligations balance is analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Balance as of January 1	$	49,833	47,289
Obligations incurred		4,306	—
Change in estimates		3,172	—
Accretion		2,681	2,544
Balance as of December 31	$	59,992	49,833

The Company accrues a decommissioning obligation associated with its facilities when the assets are placed in service. The decommissioning obligation is recorded at its estimated fair value and accretion expense is recognized to other financial expenses (note 15) over time as the discounted liability is accreted to its expected settlement value. Fair value is measured using the discounted cash flow method.

The avian regulation violation balance is analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Balance as of January 1	$	1,000	—
Obligations incurred		—	1,000
Balance as of December 31	$	1,000	1,000

Avian regulation violation relates to a pending matter with the U.S. Fish and Wildlife Service at one of the Company's wind farms. The Company has determined that it is probable that it will incur fines and/or restitution payments related to this matter. The obligations incurred are recorded as provisions expense (note 11).

The commercial litigation balance is analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Long term:			
Balance as of January 1	$	250	—
Obligations incurred		—	250
Balance as of December 31	$	250	250
Short term:			
Balance as of January 1	$	110	—
Obligations incurred		—	300
Payments		—	(190)
Balance as of December 31	$	110	110

Commercial litigation relates to instances in which the Company has probable legal settlements and associated expenses. The obligations incurred are recorded as provisions expense (note 11).

(29) Financial Debt

This balance is analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Short-term financial debt:			
General Electric Capital Corporation	$	—	1,665
Total financial debt	$	—	1,665

In December 2009, the Company entered into a five-year loan agreement with General Electric Capital Corporation. The Company borrowed $7 million and is to repay the principal and total interest of $1.6 million in 20 equal quarterly payments of $425 thousand and one payment of $140 thousand, which was made in 2009. The loan has an imputed interest rate of 8.49%, and was fully repaid as of December 31, 2014.

For the years ended December 31, 2014 and 2013, the Company incurred interest costs from this loan of $35 thousand and $170 thousand, respectively.

(30) Trade and Other Payables

This balance is analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Long-term payables:			
Interconnection facility payable	$	2,191	2,228
	$	2,191	2,228
Short-term payables – current:			
Property and equipment suppliers	$	538,148	57,877
Services and other suppliers		5,244	4,515
Construction liability		28,880	47,024
Payroll accrual		1,621	1,412
Bonus accrual		8,114	7,504
Other deferred income		4,403	10,762
Property tax accrual		19,814	18,449
Other taxes payable		1	1
Output guarantee expense (notes 10 and 34)		15,000	13,286
Other creditors and sundry operations		22,774	24,900
	$	643,999	185,730

Property and equipment suppliers increased in 2014 due to invoiced construction activity performed in 2014 that will not be paid for until 2015.

Construction liabilities decreased in 2014 due to the payment of a 2013 executed asset purchase paid for in 2014 (note 20) net of increased completed construction activity not yet invoiced.

Interconnection facility payable relates to a transmission provider, who in accordance with the transmission services agreement, elected the option for the Company to pay for network upgrades of $2.2 million over 30 years. The Company is to pay $421 thousand annually and the obligation has an implied interest rate of 18.75%. The payable is related to the $2.9 million substation access rights intangible asset (note 20) net of $661 thousand of cash previously paid for the asset.

The aggregate maturities of the interconnection facility payable are as follows:

		Principal	Implied interest	Total
		(U.S. dollars in thousands)		
Year ending December 31:				
2015	$	4	417	421
2016		5	416	421
2017		6	415	421
2018		7	414	421
2019		9	412	421
Thereafter		2,160	6,301	8,461
	$	2,191	8,375	10,566

(31) Deferred Income

		2014	2013
		(U.S. dollars in thousands)	
Other deferred income – state grants	$	10,844	11,430
Deferred income – U.S. Treasury cash grant		468,329	490,838
Power sales contracts		1,140	1,140
	$	480,313	503,408

Other deferred income – state grants is analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Balance as of January 1	$	11,430	12,016
Grants received		—	—
Income recognized		(586)	(586)
Balance as of December 31	$	10,844	11,430

Other deferred income – state relates to a state government incentive for renewable energy investment. The amount received is recognized to amortization of deferred income over the useful life of the wind farm (note 14).

Deferred income – U.S. Treasury cash grant is analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Balance as of January 1	$	490,838	393,085
Grants received		—	120,243
Income recognized		(22,509)	(22,490)
Balance as of December 31	$	468,329	490,838

Deferred income – U.S. Treasury cash grant relates to the Treasury cash grant for entities not in institutional equity partnerships (note 27) as described in note 14. The amount received is recognized to amortization of deferred income over the useful life of the wind farm.

Power sales contracts are analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Balance as of January 1	$	1,140	—
Purchases		—	1,140
Balance as of December 31	$	1,140	1,140

Power sales contracts relate to amounts ascribed to power sales contracts that were purchased. These values will be amortized using the straight-line method over the term of the power sales contracts.

(32) Due to Affiliates

This balance is analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Short-term debt and borrowings:			
EDP guarantee fees	$	1,452	886
EDPR management fees		4,683	5,258
EDP Sucursal management fees		162	487
EDP Valor management fees		471	521
Other		31	820
	$	6,799	7,972

The Parent charges guarantee fees for the contractual credit support they provide for the power purchase agreements with subsidiaries in institutional equity partnerships (note 27).

EDPR management fees are charged by the Parent for the management and administrative support provided. These fees are expected to be charged for the Parent's ownership duration.

Refer to *Related-Party Transaction* (note 35) for further discussion on Due to affiliates.

(33) Derivative Financial Instruments

In accordance with IAS 39, as discussed in note 2(d), the Company may elect to classify derivatives as fair value or cash flow hedges if they meet certain criteria. Changes in the fair value of those derivatives classified as hedges is recognized in equity, while changes in the fair value of derivatives not designated as hedges are recognized in income.

During 2014 and 2013, EDPR NA was a party to two types of derivative instruments:

(a) Power Price Swap

EDPR NA entered into a power price swap to hedge the variability in the spot market prices received for a portion of the production from the Maple Ridge I project. This instrument was not designated as a hedge for accounting purposes until May 1, 2008. Prior to the designation as a hedge, changes in the fair value of the swap were recorded in earnings. Subsequent to the designation as a hedge, settlements under the swap are recognized as a component of revenue, while changes in the fair value of the portions of the swap that will be settled in the future are recorded in the fair value reserve. This instrument expired in 2012 and the final cash settlement occurred in 2013.

(b) Power Price Swaps – Locational Basis Difference

During 2014 and 2013, the Company entered into various power price swaps to hedge the variability in the locational spot market prices received in various U.S. power markets at various projects located within those markets. Locational spot market power prices consist of a market energy price, which is consistent through a given market, and a congestion and line loss component, which create pricing variability depending where a generator is located on the market power grid. These swaps are intended to hedge both the congestion and line loss components as well as fix the market energy price. A portion of these instruments are designated as hedges. Changes in the fair value of swaps not designated as hedges were recorded in earnings. Settlements under the swaps designated as hedges were recognized as a component of revenue, while changes in the fair value of the portions of these swaps that will be settled in the future are recorded in the fair value reserve. During 2010, the swaps related to congestion and line loss were determined to be ineffective hedges and were no longer designated as hedges.

The net balances and fair values of the Company's derivative financial instruments are analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Derivatives held for trading:			
Power price swap – locational basis difference	$	(1,174)	(4,388)
Cash flow hedges:			
Power price swap – locational basis difference		5,907	(2,854)
Total cash flow hedges		5,907	(2,854)
Net derivative financial instruments	$	4,733	(7,242)

The changes in the fair value of derivative instruments and risks being hedged are analyzed as follows:

				Fair value changes			
				2014		2013	
Hedge type	Hedging instrument	Hedged risk		Instruments	Risk	Instruments	Risk
				(U.S. dollars in thousands)			
Derivatives designated as hedges:							
Cash flow hedge	Power price swap (since designated as a hedge)	Changes in spot market power prices	$	—	—	(1,226)	(1,226)
	Power price swaps – locational basis difference (designated as a hedge)	Changes in spot market power prices		8,761	8,761	(3,614)	(3,614)
Disqualified cash flow hedge	Power price swap (fair value at disqualification)	Changes in spot market power prices		—	—	1,226	1,226
	Power price swaps – locational basis difference (fair value at liquidation)	Changes in spot market power prices		(1,537)	(1,537)	—	—
	Power price swaps – locational basis difference (fair value at disqualification)	Changes in spot market power prices		—	—	1,806	1,806
			$	7,224	7,224	(1,808)	(1,808)

Hedge type	Hedging instrument	Hedged risk	Fair value changes 2014 Instruments	2014 Risk	2013 Instruments	2013 Risk
			(U.S. dollars in thousands)			
Derivatives not designated as hedges:						
	Power price swaps – locational basis difference (not designated as a hedge)	Changes in spot market power prices	$ 3,214	3,214	(1,646)	(1,646)
Disqualified cash flow hedge	Power price swap (fair value change since disqualification)	Changes in spot market power prices	—	—	(1,226)	(1,226)
	Power price swaps – locational basis difference (fair value change since disqualification)	Changes in spot market power prices	—	—	(4,429)	(4,429)
			$ 3,214	3,214	(7,301)	(7,301)

During 2014, the Company entered into a locational basis power price swap that was initially hedge qualified. Market forces led the Company to pay $1.5 million to cancel the swap. The unrealized loss at the time of liquidation remains in fair value reserves and the Company will reclassify this portion of the fair value reserve to earnings, as a component of revenue, in the remaining settlement periods to which the fair value related at the date of disqualification.

During 2013, the Company entered into a locational basis power price swap that was initially hedge qualified. Market forces led the Company to discontinue hedge accounting and the Company later canceled the swap in exchange for $4.4 million. The unrealized loss at the time of disqualification will remain in fair value reserves and the Company will reclassify this portion of the fair value reserve to earnings, as a component of other financial income, in the remaining settlement periods to which the fair value related at the date of disqualification.

On January 1, 2013, the Company discontinued hedge accounting for a derivative instrument related to Flat Rock I after the Company ceased to consolidate this entity upon the adoption of IFRS 11. The unrealized loss at the time of disqualification was reclassified from fair value reserves to other financial income during 2013 as the settlement periods to which the fair value related at the date of disqualification occurred during 2013.

For the 2014 and the 2013 financial years, the movements in the fair value reserve related to cash flow hedges were as follows:

		2014	2013
		(U.S. dollars in thousands)	
Balance at beginning of year	$	(1,321)	(2,227)
Fair value changes		7,224	(1,808)
Unwinding of reserve at qualification for hedge accounting		—	(175)
Unwinding of reserve at disqualification for hedge accounting		1,191	399
Transfers of hedge settlements to results		(1,342)	3,022
Tax effect on fair value reserve		(2,710)	(532)
Balance at end of year	$	3,042	(1,321)

The power price swap commenced in April 2006, but was not qualified for hedge accounting until May 1, 2008. At that time, the fair value of the swap was a liability of approximately $8.9 million, creating a basis difference between the fair value reserve and fair market value of the swap. The Company will reclassify this portion of the fair value reserve to earnings, as a component of other financial income, in the remaining settlement periods to which the fair value related as of May 1, 2008.

The gains and losses on the derivatives portfolio recorded in the consolidated statements of income are analyzed as follows:

		2014	2013
		(U.S. dollars in thousands)	
Derivatives held for trading	$	4,799	1,444
Cash flow hedge:			
Power price swap		—	—
Power price swap – locational basis difference		(13,087)	(4,946)
	$	(8,288)	(3,502)

Power price swap gains and losses are recorded in energy sales for settlement periods that have already occurred.

At December 31, 2014, the expected periods in which the cash flows associated with derivatives classified as hedges are expected to occur and the fair values of the related hedging instruments are analyzed as follows:

	Up to 3 months	3 months to 1 year	1 year to 5 years	More than 5 years	Total
			(U.S. dollars in thousands)		
Expected cash flows:					
Power price swap – locational basis difference	$ 1,353	4,322	214	—	5,889
Total	$ 1,353	4,322	214	—	5,889
Fair value:					
Power price swap – locational basis difference	$ 1,347	4,199	361	—	5,907
Total	$ 1,347	4,199	361	—	5,907

At December 31, 2013, the expected periods in which the cash flows associated with derivatives classified as hedges are expected to occur and the fair values of the related hedging instruments are analyzed as follows:

	Up to 3 months	3 months to 1 year	1 year to 5 years	More than 5 years	Total
			(U.S. dollars in thousands)		
Expected cash flows:					
Power price swap – locational basis difference	$ (1,845)	852	(2,239)	—	(3,232)
Total	$ (1,845)	852	(2,239)	—	(3,232)
Fair value:					
Power price swap – locational basis difference	$ (1,840)	823	(1,837)	—	(2,854)
Total	$ (1,840)	823	(1,837)	—	(2,854)

At December 31, 2014, the anticipated periods during which the hedge settlements will be reclassified to earnings is analyzed as follows:

	Up to 3 months	3 months to 1 year	1 year to 5 years	More than 5 years	Total
			(U.S. dollars in thousands)		
Power price swap – locational basis difference	$ 1,260	3,933	169	—	5,362
Fair value at hedge disqualification	(655)	(1,375)	1,604	—	(426)
Tax effect on fair value reserve	(232)	(978)	(684)		(1,894)
Total	$ 373	1,580	1,089	—	3,042

At December 31, 2013, the anticipated periods during which the hedge settlements will be reclassified to earnings is analyzed as follows:

	Up to 3 months	3 months to 1 year	1 year to 5 years	More than 5 years	Total
			(U.S. dollars in thousands)		
Power price swap – locational basis difference	$ (1,043)	823	(1,837)	—	(2,057)
Fair value at hedge disqualification	(515)	(677)	1,112	—	(80)
Tax effect on fair value reserve	595	(56)	277	—	816
Total	$ (963)	90	(448)	—	(1,321)

(34) Commitments and Contingencies

As of December 31, 2014 and 2013, the financial commitments and guarantees provided that are not recorded in the consolidated statements of financial position are analyzed as follows:

	2014	2013
	(U.S. dollars in thousands)	
Commitments:		
Land and office leases	$ 688,393	622,154
Turbine purchases	1,061,089	120,598
Transmission commitments	61,109	68,714
Other contractual commitments	747,392	84,947
Total commitments	$ 2,557,983	896,413

Other contractual commitments increased due to the execution of construction-related contracts during 2014.

	December 31, 2014			
	Commitments by period			
	Total	Up to 1 year	1 to 5 years	More than 5 years
	(U.S. dollars in thousands)			
Land and office leases	$ 688,393	23,015	96,923	568,455
Turbine purchases	1,061,089	481,864	579,225	—
Transmission commitments	61,109	6,816	10,497	43,796
Other contractual commitments	747,392	393,423	353,969	—
	$ 2,557,983	905,118	1,040,614	612,251

Land and office leases include the minimum amounts due to holders of land leases. Amounts due under certain of these leases are indexed to inflation and also may vary if electricity revenues exceed established minimum amounts.

Output Guarantees

The Company has entered into multiple power purchase agreements that require minimum quantities of electricity be generated by specific generation facilities over various durations of time. If these minimum quantities are not met then liquidated damages may be assessed. Generally, the damages are calculated by multiplying the electricity generation deficit by the difference between the average market and contract price during the period. Damages are not payable by the Company if market prices do not exceed the contract price. The Company has not paid any liquidated damages or recorded any liabilities related to its output guarantees.

During 2012, the Company entered into an agreement with a noncontrolling interest holder guaranteeing the output of the facilities of which they have a noncontrolling interest. The agreement term is four years, with settlements occurring every two years in 2014 and 2016. The maximum exposure resulting from this agreement is approximately $21 million. Based on actual output and current projections, the Company has recorded a liability of $15 million and recognized expense of approximately $1.7 million and $13.3 million for the years ended December 31, 2014 and 2013, respectively (notes 10 and 30).

(35) Related-Party Transactions

The Company transacted with EDP and EDPR in the reporting period. Amounts payable to and receivable from EDP and EDPR are recorded in due to affiliates (note 32) and loans to subsidiaries in debtors and other assets (note 24). The Company expensed guarantee fees (note 15) from EDP and a management fee from EDPR (note 8). The terms and conditions of the transactions with key management personnel and their related parties were no more favorable than those available, or which might reasonably be expected to be available, on similar transactions to nonkey management personnel related entities on an arm's length basis.

Key Management Personnel Compensation

The compensation of the Company's officers is set by EDPR, as sole member.

Compensation of the key management of the Company was as follows:

		2014	2013
		(U.S. dollars in thousands)	
Compensation	$	3,688	3,303
Employee benefits		145	225
Retirement plan (note 2(j))		95	130
Total	$	3,928	3,658

(36) Fair Values of Financial Assets and Liabilities

The Company adopted IFRS 9 (2010), *Financial Instruments*, and IFRS 13, *Fair Value Measurement*, for the years ended December 31, 2014 and 2013, which is required to be adopted by January 1, 2015. Early adoption of IFRS 9 did not materially impact the consolidated financial statements, but created additional fair value disclosures in the consolidated financial statements. Fair value of financial instruments is based, whenever available, on quoted market prices. Otherwise, fair value is determined through internal models, which are based on generally accepted cash flow discounting techniques and option valuation models or through quotations supplied by third parties.

Cash, Trade Receivables, Debtors and Other Assets, Trade and Other Payables, and Financial Debt

These financial instruments include mainly short-term financial assets and liabilities. Given their short-term nature at the reporting date, their book values are not significantly different from their fair values.

See note 3 for other assumptions used in certain fair value calculations.

The fair values of assets and liabilities at December 31, 2014 and 2013 are analyzed as follows:

	December 2014			December 2013		
	Carrying amount	Fair value	Difference	Carrying amount	Fair value	Difference
	(U.S. dollars in thousands)			(U.S. dollars in thousands)		
Financial assets:						
Trade receivables	$ 52,726	52,726	—	54,598	54,598	—
Debtors and other assets	69,407	69,407	—	76,403	76,403	—
Derivative financial instruments	22,753	22,753	—	11,019	11,019	—
Cash	191,785	191,785	—	47,136	47,136	—
	$ 336,671	336,671	—	189,156	189,156	—
Financial liabilities:						
Derivative financial instruments	$ 18,020	18,020	—	18,261	18,261	—
Financial debt	—	—	—	1,665	1,665	—
Provisions for liabilities and charges	61,242	61,242	—	51,083	51,083	—
Due to affiliates	6,799	6,799	—	7,972	7,972	—
Creditors and other payables	633,705	633,705	—	185,730	185,730	—
	$ 719,766	719,766	—	264,711	264,711	—

When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 – quoted prices (unadjusted) in active markets for identical assets or liabilities
- Level 2 – inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices)
- Level 3 – inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The fair value levels used to evaluate the Company's financial assets and liabilities are defined as follows:

	December 2014			December 2013		
	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
	(U.S. dollars in thousands)			(U.S. dollars in thousands)		
Financial assets:						
Trade receivables	$ —	52,726	—	—	54,598	—
Debtors and other assets	—	69,407	—	—	76,403	—
Derivative financial instruments	—	22,753	—	—	11,019	—
Cash	191,785	—	—	47,136	—	—
	$ 191,785	144,886	—	47,136	142,020	—
Financial liabilities:						
Derivative financial instruments	$ —	18,020	—	—	18,261	—
Financial debt	—	—	—	—	1,665	—
Provisions for liabilities and charges	—	61,242	—	—	51,083	—
Due to affiliates	—	6,799	—	—	7,972	—
Creditors and other payables	—	633,705	—	—	185,730	—
	$ —	719,766	—	—	264,711	—

Sensitivity Analysis

The values of the Company's derivative financial instruments are subject to changes in spot market power prices and changes in interest rates that are used to discount nominal amounts to present value. Below is a summary of the impacts on equity and net income related to the fair value of derivative financial instruments using a 1% change in spot market power prices and interest rates.

	One-percentage increase		One-percentage decrease	
	Equity	Net income	Equity	Net income
	(U.S. dollars in thousands)			
December 31, 2014:				
Spot market power prices	$ (635)	(41)	635	(41)
Interest rates (discount rates)	10	11	(11)	(12)
December 31, 2013:				
Spot market power prices	$ (998)	31	998	(31)
Interest rates (discount rates)	118	56	(122)	(57)

(37) New Standards Not Yet Adopted

The Company does not expect the new, but not yet effective, standards and interpretations issued by the IASB to have a material impact on the Company's consolidated financial statements.

(38) Subsequent Events

The Company has evaluated subsequent events from the consolidated statement of financial position date through April 30, 2015, the date at which the consolidated financial statements were authorized to be issued.

In April 2015, the Company sold non-controlling Project Sponsor interests in the following institutional equity partnerships in exchange for $348 million. The transaction was executed on August 19, 2014, but did not achieve all necessary regulatory approvals until 2015. Any gain (loss) from the sale will be recognized in 2015 as equity to result of sale on controlling interests, net of tax.

	Project Sponsor Interest Sold
2008 Vento III, LLC	25%
2009 Vento V, LLC	49
2011 Vento IX, LLC	49
2014 Vento XI, LLC	49
2014 Vento XII, LLC	49%

(39) List of Companies

As of December 31, 2014, EDPR NA's subsidiary companies included in the consolidated accounts under the full consolidated method are as follows:

	Ownership percentage
EDP Renewables North America LLC	100.00%
Wind Turbine Prometheus, LP	100.00
Cloud County Wind Farm, LLC	100.00
Blue Canyon Wind Power II LLC	100.00
Telocaset Wind Power Partners, LLC	100.00
High Trail Wind Farm, LLC	100.00
Marble River, LLC	100.00
Aroostook Wind Energy LLC	100.00
Jericho Rise Wind Farm LLC	100.00
Madison Windpower LLC	100.00
Mesquite Wind, LLC	100.00
Martinsdale Wind Farm LLC	100.00
Post Oak Wind, LLC	100.00
BC2 Maple Ridge Wind LLC	100.00
High Prairie Wind Farm II, LLC	100.00
Arlington Wind Power Project LLC	100.00
Signal Hill Wind Power Project LLC	100.00
Tumbleweed Wind Power Project LLC	100.00
Old Trail Wind Farm, LLC	100.00
OPQ Property LLC	100.00
2007 Vento I, LLC	100.00
2007 Vento II, LLC	51.00
2008 Vento III, LLC	100.00
2009 Vento IV, LLC	100.00
2009 Vento V, LLC	100.00
2009 Vento VI, LLC	100.00

	Ownership percentage
2010 Vento VII, LLC	100.00%
2010 Vento VIII, LLC	100.00
2011 Vento IX, LLC	100.00
2011 Vento X, LLC	100.00
2014 Vento XI, LLC	100.00
2014 Vento XII, LLC	100.00
2014 Sol I, LLC	100.00
Horizon Wind Ventures I, LLC	100.00
Horizon Wind Ventures II, LLC	100.00
Horizon Wind Ventures III, LLC	100.00
Horizon Wind Ventures VI, LLC	100.00
Horizon Wind Ventures VII, LLC	100.00
Horizon Wind Ventures VIII, LLC	100.00
Horizon Wind Ventures IX, LLC	100.00
EDPR Wind Ventures X, LLC	100.00
EDPR Wind Ventures XI, LLC	100.00
EDPR Wind Ventures XII, LLC	100.00
EDPR Solar Ventures I, LLC	100.00
Clinton County Wind Farm, LLC	100.00
Whitestone Wind Purchasing LLC	100.00
Rail Splitter Wind Farm, LLC	100.00
Pioneer Prairie Wind farm I LLC	100.00
Pioneer Prairie Wind farm II LLC	100.00
Sagebrush Power Partners, LLC	100.00
Wheat Field Wind Power Project LLC	100.00
Darlington Wind Farm, LLC	100.00
Blue Canyon Wind Power V LLC	100.00
Blue Canyon Windpower VI	100.00
Blackstone Wind Farm, LLC	100.00
Blackstone Wind Farm II, LLC	100.00
Blackstone Wind Farm III	100.00
Black Prairie Wind Farm LLC	100.00

(Continued)

	Ownership percentage
Meadow Lake Wind Farm, LLC	100.00%
Meadow Lake Wind Farm II, LLC	100.00
Meadow Lake Wind Farm III, LLC	100.00
Meadow Lake Wind Farm IV, LLC	100.00
Meadow Lake WF V LLC	100.00
Saddleback Wind Power Project, LLC	100.00
Lexington Chenoa Wind Far	100.00
Lexington Chenoa Wind II	100.00
Paulding Wind Farm LLC	100.00
Paulding Wind Farm II LLC	100.00
Antelope Ridge Wind Power	100.00
Waverly Wind Farm LLC	100.00
Rising Tree Wind Farm LLC	100.00
Sustaining Power Solutions LLC	100.00
Green Power Offsets LLC	100.00
Rising Tree Wind Farm II LLC	100.00
Rising Tree Wind Farm III LLC	100.00
Wheat Field Holding LLC	51.00
Arbuckle Mountain Wind Farm LLC	100.00
Lone Valley Solar Park I LLC	100.00
Lone Valley Solar Park II LLC	100.00
Number Nine Wind Farm, LLC	100.00
Headwaters Wind Farm LLC	100.00
Hidalgo Wind Farm LLC	100.00

The following subsidiaries of EDPR NA were incorporated at December 31, 2014 but have had no activity since incorporation:

	Ownership percentage
17th Star Wind Farm LLC	100.00%
Alabama Ledge Wind Farm, LLC	100.00
Arkwright Summit Wind Farm, LLC	100.00
Ashford Wind Farm, LLC	100.00
Athena-Weston Wind Power Project, LLC	100.00
Athena-Weston Wind Power Project II, LLC	100.00
AZ Solar, LLC	100.00
BC2 Maple Ridge Holdings, LLC	100.00
Black Prairie Wind Farm II, LLC	100.00
Black Prairie Wind Farm III, LLC	100.00
Blackstone Wind Farm IV, LLC	100.00
Blackstone Wind Farm V, LLC	100.00
Blue Canyon Windpower III, LLC	100.00
Blue Canyon Windpower IV, LLC	100.00
Blue Canyon Windpower VII, LLC	100.00
Broadlands Wind Farm, LLC	100.00
Broadlands Wind Farm II, LLC	100.00
Broadlands Wind Farm III, LLC	100.00
Buffalo Bluff Wind Farm, LLC	100.00
Chateauguay River Wind Farm, LLC	100.00
Cloud West Wind Project, LLC	100.00
Coos Curry Wind Power Project, LLC	100.00
Cropsey Ridge Wind Farm, LLC	100.00
Crossing Trails Wind Power Project, LLC	100.00
Dairy Hills Wind Farm, LLC	100.00
Diamond Power Partners, LLC	100.00
East Klickitat Wind Power Project, LLC	100.00
Eastern Nebraska Wind Farm LLC	100.00
Five-Spot, LLC	100.00
Ford Wind Farm, LLC	100.00
Franklin Wind Farm LLC	100.00
Gulf Coast Windpower Management Company, LLC	100.00

(Continued)

	Ownership percentage
Horizon Wind Chocolate Bayou, LLC	100.00%
Horizon Wind Energy Midwest IX, LLC	100.00
Horizon Wind Energy Northwest I, LLC	100.00
Horizon Wind Energy Northwest IV, LLC	100.00
Horizon Wind Energy Northwest VII, LLC	100.00
Horizon Wind Energy Northwest X, LLC	100.00
Horizon Wind Energy Panhandle I, LLC	100.00
Horizon Wind Energy Southwest I, LLC	100.00
Horizon Wind Energy Southwest II, LLC	100.00
Horizon Wind Energy Southwest IV, LLC	100.00
Horizon Wind Energy Valley I, LLC	100.00
Horizon Wind Freeport Windpower I, LLC	100.00
Horizon Wind MREC Iowa Partners, LLC	100.00
Horizon Wyoming Transmission, LLC	100.00
Juniper Wind Power Partners, LLC	100.00
Lexington Chenoa Wind Farm III, LLC	100.00
Machias Wind Farm, LLC	100.00
Meadow Lake Wind Farm V, LLC	100.00
New Trail Wind Farm, LLC	100.00
North Slope Wind Farm, LLC	100.00
Pacific Southwest Wind Farm, LLC	100.00
Paulding Wind Farm III, LLC	100.00
Paulding Wind Farm IV, LLC	100.00
Peterson Power Partners, LLC	100.00
Pioneer Prairie Interconnection, LLC	100.00
Rio Blanco Wind Farm LLC	100.00
Rolling Upland Wind Farm LLC	100.00
Rush County Wind Farm LLC	100.00
Sardinia Windpower, LLC	100.00
Simpson Ridge Wind Farm, LLC	100.00
Simpson Ridge Wind Farm II, LLC	100.00
Simpson Ridge Wind Farm III, LLC	100.00
Simpson Ridge Wind Farm IV, LLC	100.00
Simpson Ridge Wind Farm V, LLC	100.00
Stinson Mills Wind Farm, LLC	100.00
The Nook Wind Power Project, LLC	100.00
Tug Hill Windpower, LLC	100.00
Turtle Creek Wind Farm, LLC	100.00
Western Trail Wind Project I, LLC	100.00
Whiskey Ridge Power Partners, LLC	100.00
Whistling Wind WI Energy Center, LLC	100.00
Wilson Creek Power Project, LLC	100.00
WTP Management Company, LLC	100.00

(40) Associated Companies

The main financial indicators of the associated companies accounted for using the equity method at December 31, 2014 are as follows:

Associated company	Head office		Assets	Liabilities	Equity	Total revenue	Net income (loss)	Ownership
					(U.S. dollars in thousands)			
Flat Rock Windpower LLC	Portland, OR	$	263,017	3,988	259,029	42,305	12,286	50%
Flat Rock Windpower II LLC	Portland, OR		100,517	1,753	98,764	11,141	837	50
Blue Canyon Windpower LLC	San Francisco, CA		39,160	2,523	36,637	6,594	(1,042)	25

The main financial indicators of the associated companies accounted for using the equity method at December 31, 2013 are as follows:

Associated company	Head office		Assets	Liabilities	Equity	Total revenue	Net income (loss)	Ownership
					(U.S. dollars in thousands)			
Flat Rock Windpower LLC	Portland, OR	$	282,151	3,631	278,520	33,474	4,984	50%
Flat Rock Windpower II LLC	Portland, OR		107,067	1,618	105,449	7,887	(2,082)	50
Blue Canyon Windpower LLC	San Francisco, CA		43,404	2,484	40,920	6,298	(1,740)	25

The Company recovered its investment through cash distributions in 2008 and carries a $0 carrying value. Blue Canyon I currently has a retained deficit, and the Company will not record equity earnings until the partnership has retained earnings. The Company has not recognized losses related to Blue Canyon I of $0.26 million and $0.43 million in 2014 and 2013, respectively, since the Company has no obligation in respect of these losses.

ATTACHMENT B: LETTER OF COMMITMENT FROM EDPR

renewables

August 10, 2015

Ms. Jessica Damon
Maine Department of Environmental Protection
106 Hogan Road
Bangor, Maine 04401

Dear Ms. Damon:

EDP Renováveis S.A. ("EDPRSA") owns 100% of the membership interests in EDP Renewables North America, LLC, a Delaware limited liability company headquartered in Houston, Texas, which, in turn, owns 100% of the membership interests in Number Nine Wind Farm LLC ("Number Nine"). Number Nine submitted a combined Natural Resources Protection Act and Site Law of Development application ("Application") dated July 16, 2015 for the construction and operation of up to 119 wind turbine generators and related infrastructure (the "Number Nine Wind Farm"). EDPRSA is committed to financially supporting the construction and operation of the Number Nine Wind Farm.

As the designated equity provider to Number Nine, EDPRSA agrees to advance or provide or cause to be advanced or provided 100% of the Total Project Costs for the construction and operation of the Number Nine Wind Farm (the "Commitment"). As specified in Section 3 of the Application, the Total Project Cost is estimated to be $606 million. EDPRSA reserves the right to fund less than the Total Project Costs if tax equity, cash equity financing or other debt or equity financing can be secured for the Number Nine Wind Farm.

This Commitment is contingent upon and subject to the following conditions precedent: (i) the Permits sought in the Application have been granted on terms and conditions satisfactory to EDPRSA, acting reasonably; (ii) the Number Nine Wind Farm has received all other permits and governmental approvals necessary for the construction, maintenance and operation of the Number Nine Wind Farm, on terms and conditions satisfactory to EDPRSA, acting reasonably; and (iii) the Number Nine Wind Farm has entered into and maintains all

EDP Renewables Europe S.L.
Serrano Galvache, 56
Centro Empresarial Parque Norte, Edificio Encina
28033 Madrid - España
T: +34 902 830 700 F: +34 913 997 901
Inscrita en registro mercantil de Asturias. Tomo 3345, L-0, F-89
Hoja nº AS-32359, C.I.F. A-74137100

necessary rights under all agreements necessary for the construction, maintenance and operation of the Number Nine Wind Farm, including without limitation, power purchase agreements and other similar agreements on terms and conditions satisfactory to EDPRSA, acting reasonably.

Sincerely,

Miguel Dias Amaro
Chief Financial Officer, EDP Renováveis S.A.
Serrano Galvache, 65 – Edificio OLMO C.P. 28033
Madrid, Spain
Phone: 902-830-700

ATTACHMENT C: FIRE SAFETY FEATURES OF THE GAMESA G114 TURBINES

1. AIM

The purpose of this ECM is evaluating the risk of fire associated with the Gamesa G114 2.0MW and 2.1MW wind turbine generator models for Number 9 wind farm project, developed by EDPR, in the State of Maine. Health and safety and the risk of fires are taken very seriously by Gamesa. Health and Safety is not just our main priority but it is intrinsically embedded in our values. Turbines are, thus, designed to minimize risks.

2. ELECTRICAL EQUIPMENT

The importance of safety at Gamesa demands electrical safety is a major design focus for all Gamesa wind turbines, including the G114 2.0MW and 2.1MW models. A proper design and quality evaluation of the electrical systems is essential to assure protection of personnel and to minimize any potential risk of fire.

One source of potential fire in a wind turbine is the step up transformer. The Gamesa G114 2.0MW and 2.1MW turbines minimize the risk by using dry type transformers that are air cooled and physically separated from other components in the nacelle. The risk of an electrical arc and fire is thus reduced.

Hundreds of signals in Gamesa turbines are monitored. These signals include among others temperature, current, and voltage measurements, to ensure that the turbines are operating within acceptable operational ranges. The turbine is designed to safely de-rate or shut down if any parameter exceeds safety thresholds. These control logics are recommended by the Confederation of Fire Protection Associations in Europe and other international bodies.

In case of an electrical arc incident, arc detectors are positioned in all turbines to instantaneously detect the arc, safely shut down the turbine, and open the main switchgear. This system acts independently of the control system, and removes the energy source.

By sending the turbine to Pause mode it may pitch the blades automatically, using stored hydraulic energy, forcing the rotor to come to a complete stop within seconds. Not requiring use of a mechanical disc brake.

There are smoke detectors located inside all nacelles. Smoke detectors act independently from the turbine controller and automatically shut down the turbine and open the main switchgear of the turbine using the same procedures as the arc detectors.

Manufacturing quality is essential for ensuring the effectiveness of the electrical safety systems in the turbine. Gamesa uses state-of-the-art quality systems in its manufacturing facilities, and imposes its quality system requirements to equipment suppliers, to ensure that product quality enhances fire safety. Sophisticated tooling assures that bolted connections are at the correct torque value, cable connections are secure, and the entire turbine functions properly before leaving the manufacturing facilities. Each turbine undergoes full-scale testing both in the factory and at the site before it is considered approved for operation.

3. LIGHTNING PROTECTION

Gamesa G114 2.0MW and 2.1MW units are designed to lightning protection level 1 as per defined in IEC 61400-24 and IEC 62305-1 standards. This is the highest protection level, corresponding to safe conduction of lightning strikes up to 200 kA.

The lightning protection system of the Gamesa 2.0 MW and 2.1MW turbines is a proven design, refined over many previous turbine models, incorporating design best practices to ensure safe operation for the duration of the turbine's life.

During the turbine design phase Gamesa validated the performance of the lightning protection system according to all applicable IEC test standards in state-of-the art facilities.

The system is designed to transfer lightning strikes safely to ground. The lightning protection system extends from the tip of the blades to the nacelle, the tower, and to the foundation grounding system.

4. HOT SURFACES

Hot surfaces are kept to a minimum in the G114 2.0MW and 2.1MW turbines.

In order to bring the rotor to pause the hydraulic pitch system is used. Each blade of the wind turbine has its own pitch actuator, and in case of problems with the pitch system only one blade is required to bring the rotor to a complete stop. The mechanical disc brake in the G114 2.0MW and 2.1MW units is only used for service activities (stopping rotation of the rotor so that the rotor lock pins can be installed) or when a technician physically presses the emergency stop button.

During an emergency stop, the mechanical disc brake is only applied at low rotational speeds to limit the amount of heat build-up, and the brake is automatically released afterwards so that brake friction doesn't cause excessive heat. The disc brake is covered by a protective shield.

5. WORK INVOLVING FIRE HAZARDS

Welding, burning, grinding, and other work involving heat sources are not part of the standard installation or maintenance plan of the turbine. Such work typically takes place in the factory during the manufacturing process, or in workshops in the case of component repair.

In the rare instance that "hot work" is required to be performed in the turbine (hot work in the turbine is avoided if possible) Gamesa's work instructions include requirements to ensure that personnel and equipment are safe. Precautions include ensuring the work area is free of any flammable materials, sufficient ventilation, using of fire blankets, ensuring that extinguishers are easily reachable and clean-up and inspection of the work place after the job is finished.

Technicians must complete appropriate documentation and obtain permits from site management before engaging in any hot work. Limitation and regulation for hot work are recommended by NFPA.

6. COMBUSTIBLE MATERIALS

The use of flammable materials in the turbine cannot be avoided for practical reasons, but Gamesa makes efforts to manage these risks appropriately. For example, oil is used in the hydraulic pitch system and to lubricate the gearbox. The turbine continuously monitors oil pressures and oil levels to ensure that there are no leaks. If a leak is detected the turbine is automatically shut down and technicians need to visit the turbine and repair the issue before it can be re-started.

Materials that are not essential to the operation of the turbine are not left in the machine, including cleaning solvents, rags, papers, garbage, etc. This keeps the amount of flammable materials in the turbine to a minimum.

Smoking is not allowed in Gamesa wind turbines

7. FIRE FIGHTING

Technicians may carry an additional safety kit, if not already present in the turbine, when working on the turbines (in addition to their standard personal protective equipment including safety boots, safety glasses, gloves, fall arrest equipment, etc.). This may include a CO_2 fire extinguisher and an emergency descent device. Fire blankets are required if any hot work is to be performed. These items may be stored at the site office, if not present in the turbines, and are maintained and inspected periodically.

Technicians receive training and regular refresher courses on the proper usage of these items in the case of emergency situations. Prior to each turbine visit technicians are required to check that fire extinguishers are in good condition and are not late on inspections.

8. MAINTENANCE

The Gamesa 2.0MW and 2.1MW turbines account for a carefully designed working space to ensure that technicians have enough room to safely maintain, repair, and replace equipment as needed.

In addition to LED lighting along the entire height of the tower, and throughout the nacelle, skylights provide additional lighting during daytime hours. This allows technicians to properly perform their work, ensure high quality and clean up when the work is done.

While working on the turbine, technicians must keep fire safety in mind at all times. Before performing any work, technicians prepare thorough planning documents to describe the activities that are planned to take place in the turbine and the potential hazards associated with these tasks, including confined space and risk of fire assessments.

During periodical service visits, technicians inspect and maintain a variety of components in the turbine that ensures safe operation. For example, electrical connections are inspected and re-tightened, oil filters are replaced, the disc brake is inspected, arc detectors are tested and cleaned, the transformer is inspected and cleaned, etc. These maintenance activities are considered to be important steps to mitigate the risk of fires.

Technicians are qualified to perform this work after attending regular and extensive training sessions at Gamesa's North American training facilities in Pennsylvania, as well as on the job training and certification activities.

9. CONCLUSION

For Gamesa: Health and Safety is not just our main priority but it is intrinsically embedded in our values. This is shown in the design of the Gamesa G114 2.0MW and 2.1MW wind turbines. Every aspect of the turbine from layout, to electrical design, to maintenance requirements have been developed to ensure years of safe and trouble-free operation.

These wind turbines are an excellent fit for Number 9 wind project.

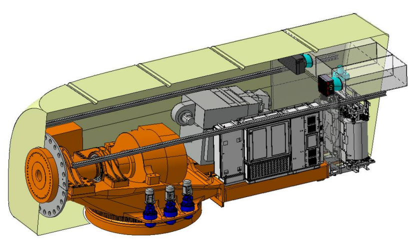
Gamesa	Engineering Coordination Memorandum (ECM)		
CODE:	**W10-01-ECM259v2**	**DATE : 08/10/2015**	
FROM:		**TO:**	
DEPARTMENT:	**PRESALES, TECHNOLOGY**	**COMPANY:**	**EDPR**
COMPANY:	**GAMESA WIND**		
SUBJECT:	**FIRE SAFETY FEATURES OF THE GAMESA G114 2.0MW AND 2.1MW TURBINES. NUMBER 9 WIND FARM PROJECT. EDPR. ADDENDUM TO W10-01-ECM233**		

1. AIM

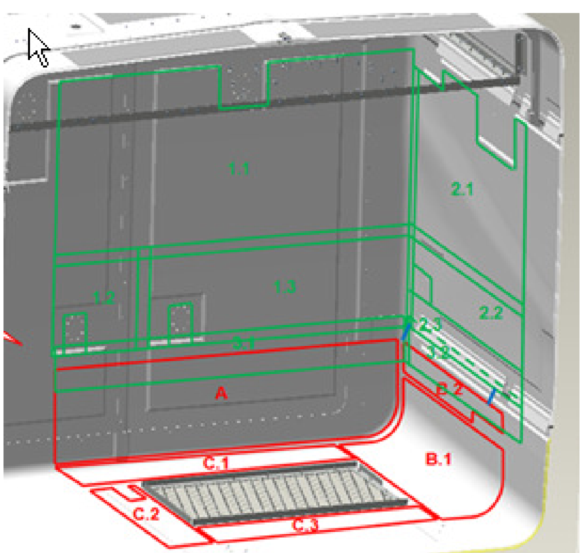
The purpose of this ECM is providing additional information to the one transmitted in W10-01-ECM233

2. ADDITIONAL DETAILS ON THE PASSIVE FIRE PROTECTION SYSTEM

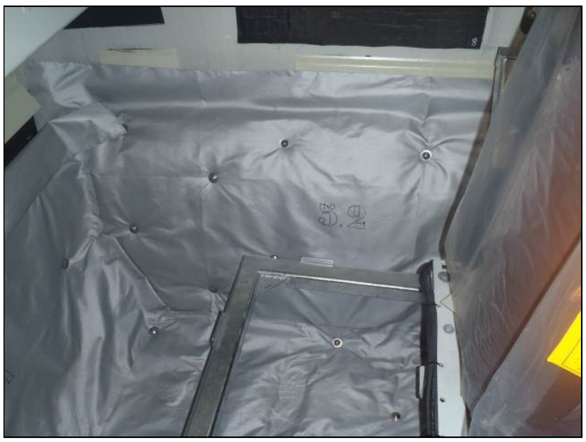
The Fire Protection System for G114 units includes the installation of fireproof panels in the transformer room. These panels are supplied as prefabricated and numbered according to their position in the transformer room. It is a passive protection system. These panels isolate the fuel source in the area of risk. The panels act as a physical barrier.
See following figure for a general mockup drawing of the nacelle, special attention to the rear of the nacelle where the transformer room is located:



See following figure for fireproof panels location in the transformer room:

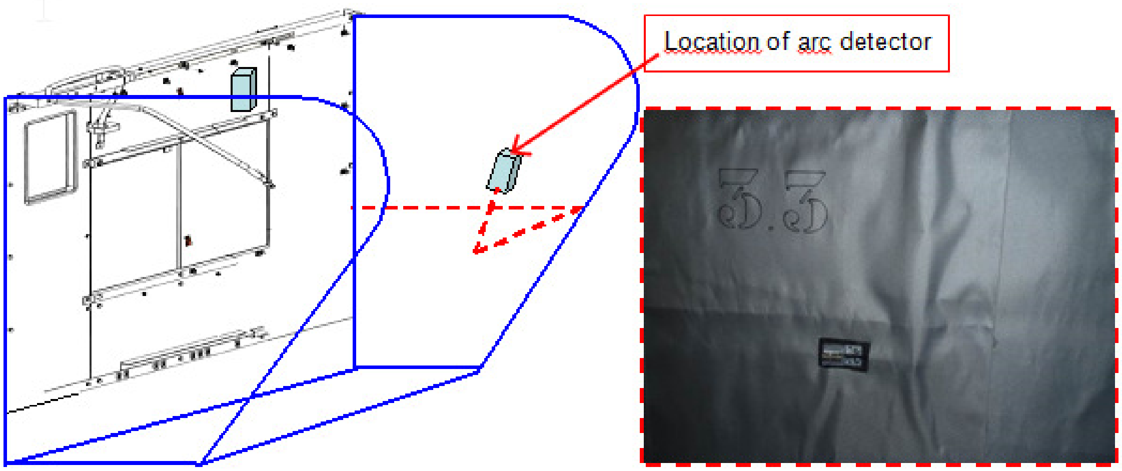


The following pictures show the system as installed in the nacelle:



See following figure for arc detector sensor location in the transformer room:

SUBJECT: FIRE SAFETY FEATURES OF THE GAMESA G114 2.0MW AND 2.1MW TURBINES. NUMBER 9 WIND FARM PROJECT. EDPR. ADDENDUM TO W10-01-ECM233



3. STANDARDS AND CERTIFICATIONS

Gamesa designs with the intent of compliance with national or widely recognized standards.
Gamesa holds, among others, the following certifications by independent entities

- See document 'ohsas-english.pdf'. OHSAS 18001:2007. Occupational health and safety management systems
- See document 'ISO9001.pdf' Quality Management Systems
- See document 'ISO 14001.pdf' Environmental Management Systems
- See document 'iso-14006-en_ecodesign.pdf' Environmental management system. Guidelines for incorporating Ecodesign.
- See document 'Iso-140642006-greenhouse-gases'
- See document 'epd-g114'.

Gamesa holds certifications according to IEC61400-1 and DIBt(German Regulations).
These certifications account for review, among others, of the following requirements:

- Loads
- Control System Architecture
- Control and Protection System, Alarm description and Design Criteria

See documents:

- 'TC-231903-A-0.pdf' by DNVGL
- 'Typenprüfung_G114-2.0MW.pdf' by TUV

4. ON SITE MONITORING

- Gamesa would service the wind farm during the warranty period. The wind farm would be operated by EDPR. A local Gamesa team, consisting of approximately 18 to 20 wind farm technicians, would be in charge of local support in the wind farm. This team would be backed up from the control center in North America (located in Trevose, PA) and the central control center(located in Spain). The wind farm would ,thus, be monitored 24/7

The Gamesa 2.0 MW and 2.1MW wind turbines would be integrated in the Gamesa WindNet®, supervisory, control and data acquisition system (SCADA), which would allow the wind farm information to be accessed through a browser. It would also integrate other wind farm equipment such as electrical substations, reactive power equipment or met masts.
With this tool, Gamesa and EDPR personnel can perform the following tasks at any time:

- Track and monitor the wind farm's equipment
- Obtain information about the energy production of each wind turbine in the wind farm
- Monitor the alarms for the different elements of the wind farm in real time and display the alarm log

As an example of the elements or variables that can be monitored:

- Smoke Sensors
- Electrical protections
- Electrical variables in the grid
- Component temperatures

Wind farm Technicians may:

- Send direct orders to the wind turbines (start, pause or switch to emergency mode) and substation
- Analyze the evolution of variables over time in a simple manner

Any wind turbine can be displayed on the system including full details of the requested data for such wind turbine. This is the type of information and actions that can be done both remotely and from the local wind farm control center

- Main information and list of alarms for the selected wind turbine
- Selection of alarms, change in status, and CMS alarms
- Historical alarm selection
- Sub-screens with all of the machine information: temperature, nacelle, and electrical information
- Possibility to send commands to the machine

Depending on the nature of the alarm such alarm may be re-set automatically, remotely or may need local re-setting at the turbine after a Technician has performed an inspection and has verified that conditions in the turbine are ok. Alarms that may be linked to the well-being of individuals or the integrity of the equipment may require local re-setting.

For further information on the system please see document 'GD180446-EN R0[1].pdf' General description of the Gamesa SCADA system.