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The World Bank

Report No: ICR3012

IMPLEMENTATION COMPLETION AND RESULTS REPORT
(IDA-43510)

ON A

CREDIT

IN THE AMOUNT OF SDR 6.0 MILLION
(US$ 9.0 MILLION EQUIVALENT)

TO

MONTENEGRO

FOR AN

ENERGY COMMUNITY OF SOUTH EAST EUROPE APL 3-MONTENEGRO PROJECT

IN SUPPORT OF THE THIRD PHASE OF THE US$ l, OOO MILLION

ENERGY COMMUNITY OF SOUTH EAST EUROPE (APL) PROGRAM

March 12, 2014

Sustainable Development Department
South East Europe Country Unit
Europe and Central Asia Region

CURRENCY EQUIVALENTS

(Exchange Rate Effective September 30, 2013)
Currency Unit = Euro
Euro 1.00 = US$ 1.3522
US$ 1.00 = Euro 0.7395
Fiscal Year in Montenegro ends on 31 December

ABBREVIATIONS AND ACRONYMS

APL	Adaptable Program Loan
BiH	Bosnia Herzegovina
CAS / CPS	Country Assistance Strategy / Country Partnership Strategy
CGES	Crnogorski Elektroprenosni Sistem AD (Transmission Company)
COTEE	Crnogorski Operator Tržišta Električne Energije (Market Operator)
EAR	European Agency for Reconstruction
EC	Energy Community
EIRR	Economic Internal Rate of Return
EMP	Environment Management Plan
ENTSO-E	European Network of Transmission System Operators of Electricity
EPCG	ElectroPriveda Crna Gora
ERA	Energy Regulatory Authority of Montenegro
EU	European Union
GWh	Giga Watt hour (one million kWh)
HPP	Hydropower Plant
HVDC	High Voltage Direct Current
IDA	International Development Agency
ISR	Implementation Status Report
KAP	Aluminum Smelter Company of Montenegro
kV / kWh	Kilo Volt / Kilo Watt Hour
LAPF	Land Acquisition Policy Framework
MW / MWh	Mega Watt / Mega Watt Hour (1000 kWh)
O&M	Operation and Maintenance
PAD	Project Appraisal Document
PIU	Project Implementation Unit
QAG	Quality Assurance Group
QER	Quality at Entry Review by QAG
SEE	South East Europe
SFR	Self Financing Ratio
TSO	Transmission System Operator
UCTE	Union for the Coordination of Transmission of Electricity
UNMIK	United Nations Interim Administration Mission in Kosovo
VAT	Value Added Tax

Vice President:	Laura Tuck (ECA)
Country Director:	Ellen Goldstein
Sector Manager:	Ranjit Lamech (ECSSD)
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MONTENEGRO
ENERGY COMMUNITY OF SOUTH EAST EUROPE APL 3-MONTENEGRO PROJECT

CONTENTS

A. Basic Information

Country:	Montenegro	Project Name:	Energy Community of South East Europe APL 3 - Montenegro Project
Project ID:	P106899	L/C/TF Number(s):	IDA-43510
ICR Date:	March 12, 2014	ICR Type:	Core ICR
Lending Instrument:	APL	Borrower:	MONTENGRO
Original Total Commitment:	XDR 6.00M	Disbursed Amount:	XDR 5.82M
Revised Amount:	XDR 6.00M		
Environmental Category: B			
Implementing Agencies: ElektroPrivreda Crne Gore **(**EPCG) and Crno Gorski Elektroprenosni Sistem AD (CGES)			
Cofinanciers and Other External Partners: None			

B. Key Dates

Process	Date	Process	Original Date	Revised / Actual Date(s)
Concept Review:	02/01/2006	Effectiveness:	01/28/2008	01/28/2008
Appraisal:	04/10/2006	Restructuring(s):		Restructuring 1 April 7, 2011 Restructuring 2 January 30, 2013
Approval:	07/06/2007	Mid-term Review:	06/15/2009	07/15/2009
		Closing:	03/31/2012	09/30/2013

C. Ratings Summary

C.1 Performance Rating by ICR

Outcomes:	Moderately Satisfactory
Risk to Development Outcome:	Low
Bank Performance:	Moderately Satisfactory
Borrower Performance:	Moderately Satisfactory

C.2 Detailed Ratings of Bank and Borrower Performance (by ICR)

Bank	Ratings	Borrower	Ratings
Quality at Entry:	Moderately Satisfactory	Government:	Moderately Satisfactory
Quality of Supervision:	Moderately Satisfactory	Implementing Agency/Agencies:	Moderately Satisfactory
Overall Bank Performance:	Moderately Satisfactory	**Overall Borrower Performance:**	Moderately Satisfactory

C.3 Quality at Entry and Implementation Performance Indicators			
Implementation Performance	**Indicators**	**QAG Assessments (if any)**	**Rating**
Potential Problem Project at any time (Yes/No):	No	Quality at Entry (QEA): March 16, 2006	Satisfactory
Problem Project at any time (Yes/No):	Yes	Quality of Supervision (QSA): April 2010	Satisfactory
DO rating before Closing/Inactive status:	Moderately Satisfactory		

D. Sector and Theme Codes

	Original	Actual
Sector Code (as % of total Bank financing)		
Hydropower	19	9
Transmission and Distribution of Electricity	81	91

Theme Code (as % of total Bank financing)		
Infrastructure services for private sector development	50	50
Regional integration	50	50

E. Bank Staff

Positions	At ICR	At Approval
Vice President:	Laura Tuck	Shigeo Katsu
Country Director:	Ellen Goldstein	Orsalia Kalantzopoulos
Sector Manager:	Ranjit Lamech	Peter Thomson
Project Team Leader:	Gazmend Daci	Husam Beides
ICR Team Leader:	Gazmend Daci	
ICR Primary Author:	Venkataraman Krishnaswamy	

F. Results Framework Analysis

Project Development Objectives (from Project Appraisal Document**)**
The objective of ECSEE APL is the development of a functioning regional electricity market in South East Europe and its integration into the internal electricity market of the European Union.

Within the overall ECSEE APL objectives/context, the objective of the ECSEE APL3-Montenegro Project is to improve the efficiency and reliability of the power system in Montenegro, through better supply security and closer integration into the regional markets.

The ECSEE APL 3 - Montenegro Project consists of the following components:

I. Telecommunications System Development
II. Transmission Network Reinforcement
III. Improvement of Operational Reliability of Perucica HPP

Revised Project Development Objectives (as approved by original approving authority)

Not Applicable

(a) PDO Indicator(s)

Indicator	**Baseline Value**	**Original Target Values (from approval documents)**	**Formally Revised Target Values**	**Actual Value Achieved at Completion or Target Years**
Indicator 1	Electricity market in SEE is liberalized in accordance with EC treaty (including derogations and subsequent modifications, if any) and a regional electricity market functioning			
Value (quantitative or qualitative)	negligible	All non-residential (NR) consumers to be liberalized by 07/01/2008 and all consumers by 01/01/2015		All non-residential consumers liberalized on target by Montenegro and all consumers will be liberalized by 01/01/2015 based on the Energy Law of 2010
Date achieved	2005	07/01/2008 (NR) 01/01/2015 (all)		07/01/2008 (NR)
Comments (including % achieved)	Achievement 100%. Liberalization is being achieved on target in Montenegro. The share of the non-residential consumers was about 62% of the total consumption in 2012. Such liberalization has taken place in varying degrees in other SEE countries (Annual Report 2013 of the EC secretariat). Sector unbundling has been substantially completed and regional electricity trading is taking place. Independent regulatory body had been established in Montenegro since 2005. Such bodies exist in most SEE countries.			
Indicator 2	The integration of the Montenegrin power system in the regional electricity market is improved through the establishment of a modern telecommunication network and			
Value (quantitative or qualitative)	No modern telecommunication network in Montenegro	All three phases of the component to be completed and communication links to two adjoining countries become operational		All three phases were completed except for some very minor items. Telecom links to BiH and Serbia are operational. A new link to Kosovo has also been constructed up to the border with Kosovo.
Date achieved	2005	3/31/2012	9/30/2013	9/30/2013

Comments (including % achieved)	Achievement is 100%. A modern telecommunication system is fully operational greatly improving the operation of the sector and its integration into the regional market. Even the pending minor works were completed in 2013. Apart from the two planned regional links to BiH and Serbia, a link to Kosovo has also been completed within the borders of Montenegro. It would be operational in August 2014 when Kosovo completes its work in its territory under KfW financing.			
Indicator 3	Transmission network in the subproject areas reinforced to reduce outages and consequent unserved energy			
Value (quantitative or qualitative)	Andrijevica SS: Outages 31 unserved energy 371 GWh Mojkovac SS: Outages 16 Unserved energy 291 GWh	Unserved energy to be reduced by 50%		Andrijevica SS: Outages 5 unserved energy 59 GWh Mojkovac SS: Operational only since August 1, 2013
Date achieved	2005	2010		2012
Comments (including % achieved)	Achievement is partial (about 80%). Andrijevica SS became operational on September 2011. Its outages had since been less than 50% of the 2005 outages. Its unserved energy level was also less than the target level. However, Mojkovac SS became operational only on 08/01/2013 and the results will have to be reviewed in the course of the next two years or so. See also the discussion in Section 3.2 of the ICR and Annex 3 on the appropriateness of these indicators.			
Indicator 4	Improvement of the operational reliability of HPP Perucica through replacement of its trash rack and trash rack cleaning system and providing spare turbine runner(s)			
Value (quantitative or qualitative)	Trash Rack system O&M cost Euro 105,000 Turbine runner O&M cost Euro 14,500	Annual O&M expenditure to be reduced by 75 % for the trash rack system and by 20% for the turbine runner(s)		Consistent data is not available on O&M costs for such items
Date achieved	2007	2010		09/30/2013
Comments (including % achieved)	Achievement is considered partial (about 80%). Works have been completed successfully by end 2009 (trash rack system) and by September 2011 (turbine runners) and the facilities are functioning very well. However EPCG had not been able to provide consistent O&M data. Quality Assurance Group suggested that reduction in the down time of the HPP station be considered. See discussion in Section 3.2 of the ICR and Annex 3.			

(b) Intermediate Outcome Indicator(s)

Indicator	Baseline Value	Original Target Values (from approval documents)	Formally Revised Target Values	Actual Value Achieved at Completion or Target Years
Indicator 1	Progress in the implementation of transmission system reinforcement			
Value (quantitative or qualitative)	0%	100%		100%
Date achieved	07/06/2007	07/06/2010	09/30/2013	09/30/2013

Comments (including % achieved)	Achievement is 100% but with delays. Andrijevica related sub-component was completed and the substation became operational on September 2011. Mojkovac related works were completed and the substation became operational in August 2013. Credit Closing Date was extended to enable such completion.			
Indicator	**Baseline Value**	**Original Target Values (from approval documents)**	**Formally Revised Target Values**	**Actual Value Achieved at Completion or Target Years**
Indicator 2	Progress in the implementation of HPP Perucica reliability improvement			
Value (quantitative or qualitative)	0%	100%		100%
Date achieved	07/06/2007	07/06/2010		09/30/2011
Comments (including % achieved)	Achievement is 100% but somewhat delayed. Replacement of Trash Rack and Trash Rack cleaning system was completed by December 2009, but the installation of the turbine runner was completed by September 2011			

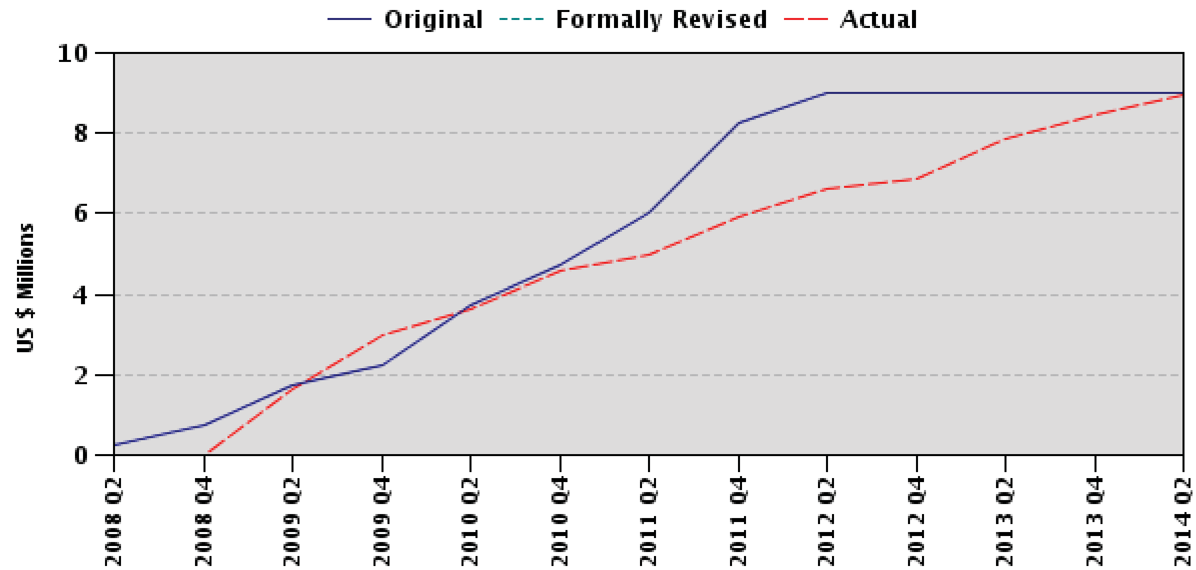
G. Ratings of Project Performance in ISRs

No.	Date ISR Archived	DO	IP	Actual Disbursements (USD millions)
1	12/21/2007	Satisfactory	Satisfactory	0.00
2	04/17/2008	Satisfactory	Satisfactory	0.00
3	12/24/2008	Satisfactory	Satisfactory	1.64
4	10/24/2009	Satisfactory	Satisfactory	3.29
5	06/30/2010	Satisfactory	Satisfactory	4.58
6	11/24/2010	Satisfactory	Satisfactory	4.96
7	03/11/2011	Satisfactory	Satisfactory	5.91
8	10/29/2011	Satisfactory	Satisfactory	6.60
9	03/30/2012	Moderately Satisfactory	Moderately Satisfactory	6.76
10	09/09/2012	Moderately Unsatisfactory	Moderately Unsatisfactory	6.89
11	12/22/2012	Moderately Unsatisfactory	Moderately Unsatisfactory	7.84
12	09/27/2013	Moderately Satisfactory	Moderately Satisfactory	8.69

H. Restructuring (if any)

Restructuring 1 04/07/2011	Implementation satisfactory. Disbursement at 64% Extends closing date from 3/31/2012 to 3/31/2013 and enables savings to be used to construct an addition regional communication link to Kosovo
Restructuring 2 01/30/2013	PDOs continue to be achievable. Disbursement at 85%. Extends the closing date by six months up to 09/30/2013

I. Disbursement Profile



1. Project Context, Development Objectives and Design

1.1 Context at Appraisal

Towards the end of the 1990s and the beginning of the next decade, studies indicated that the countries of South East Europe faced emerging energy shortages and the need for considerable investments in the energy sector to keep pace with the projected demand and support economic development. Acknowledging the benefits of a regional, rather than national approach to energy issues, nations and territories of South East Europe signed the *Treaty Establishing the Energy Community of South East Europe (ECSEE)*[1] with the European Community in Athens in October 2005. The signatories included Albania, Bulgaria, Bosnia and Herzegovina, Croatia, Greece, Kosovo (UNMIK)[2], FYR Macedonia, Montenegro,[3] Romania, and Serbia. Turkey, though an active member of the group did not sign the *Treaty* and had the status of an "observer".

The establishment of a well-functioning regional electricity market with consistent market rules and appropriate regulatory oversight was considered critical to overcome the fragmentation of energy supply and to encourage new investments needed to meet the emerging demand-supply gaps on the basis of regionally optimized least cost options. Without such a regional framework even investments of significant magnitude might leave gaps between supply and demand. A uniform region-wide institutional framework for electricity trading largely based on the EU Energy Directives was expected to improve the region's generation mix, improve efficiency of operation and energy conservation, reduce energy intensity, strengthen national institutions, and enable the countries to adopt legislation, regulation, and environmental standards consistent with those of the EU.

Recognizing the importance of the EU sponsored program for the promotion of the regional electricity market in South East Europe and its eventual integration with the internal EU market, and the importance of regional cooperation and fostering regional markets among countries previously at war to ensure peace, economic development and political stability as envisaged under the Stability Pact and *EC Treaty*, the World Bank decided to support these initiatives and approved in January 2005, a $1.0 billion horizontal APL Program to finance projects which will facilitate the emergence of regional electricity markets among the countries of South East Europe. Under the APL program seven loans/credits totaling about $410 million had been approved by mid-2007 and the credit to Montenegro was the eighth operation.

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[1] Subsequent to the effectiveness of the Athens Treaty in mid-2006, ECSEE was simply referred to as the Energy Community (EC)

[2] Kosovo is no longer a territory and has since become a country, and Montenegro became independent from Serbia and Montenegro in June 2006.

[3] Montenegro signed the *Treaty* on October 25, 2005 as The Republic of Montenegro. After becoming independent, the country is simply called Montenegro under its constitution

In 2005, Montenegro operated a modest sized power system with an installed generation capacity of 849 MW (191 MW of lignite fired thermal power plant, 649 MW of two large hydropower stations and 9 MW of seven small hydropower stations). Its transmission system consisted of 253 km of 400 kV lines, 371 km of 220 kV lines and 680 km of 110 kV lines and the Montenegro system was interconnected to Serbia (by 220 kV lines), Bosnia and Herzegovina (BiH) (by 400 kV, 220 kV and 110 kV lines), and Albania (220 kV and 400 kV lines).[4] The total transformer capacity in the transmission system was about 3,138 MVA.

Domestic electricity generation in 2005 was 2,748 GWh (about 67 percent hydro and 33 percent thermal). In addition, the country was trading in electricity with its neighbors on the basis of annual and long term contracts and also had a long term arrangement to export peak energy from its Piva HPP to Serbia in exchange for a larger volume of base load energy.[5] In 2005 it had a net energy import of 1,796 GWh. Out of the total domestic and imported electricity, about 3.1 percent was lost as transmission loss and about 47 percent (or 2,058 GWh) was sold to the three large direct consumers (the aluminum smelter (KAP), a steel plant and the national railways) and the remaining 2,310 GWh was transferred to the distribution system. The distribution system incurred a system loss of 26 percent (or 600 GWh) and sold to the distribution consumers 1,710 GWh.

The total number of customers was about 250,000, which included the above three large direct consumers and total billed sales amounted to 3,768 GWh (in which the Aluminum plant alone had a share of 1,897 GWh or 50 percent). The overall system losses worked out to 17.1 percent and the overall collection rate was about 90% of the amounts billed. [6]

The power system of Montenegro was operated by the vertically integrated state-owned power utility ElektroPrivreda Crne Gore (EPCG) and it was a state-owned monopoly responsible for generation, transmission and distribution of electricity in the country. In the context of signing the Athens Memoranda of 2002 and 2003, the government enacted in 2003 a new Energy Law, to restructure the sector on the lines envisaged in EU directives (1996/92/EC and 2003/54/EC) concerning rules for the internal market for electricity. Under this Law, EPCG was functionally unbundled into generation, transmission and distribution businesses with the target of achieving legal unbundling by 2007. An independent Energy Regulatory Agency (ERA) was also established in 2004. ERA had already hired a consultant, financed by the European Agency for Reconstruction (EAR), to assist in developing the market rules, resolving tariff issues and preparing for market liberalization to meet the *EC Treaty* requirements. In October 2004, the interconnected power systems in South East Europe (known as the second UCTE) were re-synchronized with UCTE [7] and Montenegro became part of UCTE (which

[4] The system was also connected to Kosovo by a 400 kV line in 2010.
[5] This agreement appears to have been canceled in 2013/2014.
[6] The data in this and the two previous paragraphs are from the Energy Balance statements of EPCG for 2005.
[7] Union for Coordination of Transmission of Electricity in Europe (UCTE) was later absorbed into the much wider ENTSO-E of the EU power system.

coordinates the operation and development of the transmission networks of its members) and operates synchronously with the European systems.

Electricity demand was growing at about two percent annually and solutions for cost effective generation capacity expansion were elusive. Dependence on imports was becoming more important. Tariffs lagged behind cost of supply and EPCG was generating substantial losses. The aluminum smelter which had a share of nearly 50 percent of the total billed electricity consumption was guaranteed a low electricity price till 2009 under the privatization deal and this made the tariff revisions for others even more difficult. High cost imported electricity was being provided to the aluminum smelter at a low price, thus eroding the financial viability of EPCG. The government was also pursuing a strategy of privatization in the power sector. The European Agency for Restructuring through Technical Assistance, and the Bank through the Second Structural Adjustment Credit were helping the government handle these challenges. Earlier the Bank had also provided a Credit of US$5 million for Emergency Stabilization of Electricity Supply Project which financed a Pilot Distribution Project, AMR meters and the introduction of a Financial Management System for EPCG.

The key elements of the rationale for the Bank's involvement in the APL-3 Montenegro project were: (a) the long standing partnership between the EU and the Bank in studying the problems of the Balkans, the evolution of the concept of regional integration of SEE energy systems, (b) the need to support the EU sponsored program of regional integration of the power markets of SEE countries and its eventual integration with the internal EU markets in the context of, the Athens Memoranda and the *EC Treaty*; and (c) to help Montenegro with investments needed to make generation and transmission more reliable and facilitate smoother regional operations through improvements to the communications system. The higher level objectives of the project were promotion of regional cooperation and fostering of the regional markets among countries previously at war to ensure peace, economic development and stability envisaged under the Stability Pact and the *EC treaty*. The project was consistent with the Country Assistance Strategy (CAS) (2005-2007) for Serbia-Montenegro and was relevant to two of the three goals of the CAS, namely, creation of a more sustainable and efficient public sector, and creation of a larger and more dynamic private sector. The project was expected to improve the performance of the power sector and assist in its integration with the regional market both of which were considered essential to achieve fiscal sustainability of the public sector and encourage private sector-led growth.

1.2 Original Project Development Objectives (PDO) and Key Indicators

The objective of ECSEE APL program is the development of a functioning regional electricity market in South East Europe and its integration into the internal electricity market of the European Union, through the implementation of priority investments supporting electricity market and power system operations in electricity generation, transmission and distribution, as well as technical assistance for institutional/systems development and project preparation and implementation.

Within the overall context and objective of the ECSEE APL program, the objective of the Montenegro APL-3 Project was to improve the efficiency and reliability of the power system in the Republic of Montenegro, through better supply security and closer integration into the regional markets.

The key indicators for the APL program objective were the liberalization of the electricity markets in SEE in accordance with the EC Treaty (including derogations and subsequent modifications, if any) and the functioning of a regional electricity market.

The key indicators for Montenegro APL-3 Project were: The substations have fewer blackouts, the hydropower plant generates more electricity at lower operation and maintenance cost and the company operates more efficiently with UCTE and the regional markets as a result of the improved telecommunications

The end targets were: (1) for the Telecommunications Component, the satisfactory completion of all its planned phases and the communication links with two neighboring dispatch centers being operational, (2) for the Transmission Component, a 50 percent reduction in the unserved energy in the areas served by the substations, and (3) for the Perucica Hydropower Component, a 75 percent reduction in the O&M expenses of trash rack system and a 20 percent reduction in the maintenance expenses relating to the turbine runners.

1.3 Revised PDO (as approved by original approving authority) and Key Indicators, and reasons/justification

There were no revisions of the PDO or the key indicators. However a draft review carried out by the Quality Assurance Group in April 2010, suggested revisions to the performance indicators for components 2 and 3. However there are no records in the project portal indicating that they were revised accordingly (see Section 3. 2 and Section 5.1).

1.4 Main Beneficiaries,

The PAD does not identify specific beneficiary groups. However, more reliable power supply and increased electricity trade facilitated by the project would benefit all the people in the country and especially those served by the two rehabilitated substations.

1.5 Original Components

The Project consisted of the following three components: (1) Telecommunications System Development involving the development of a modern telecommunications network, including links with regional utilities; (2) Transmission Network Reinforcement involving the construction of two transmission line circuits from the transmission network to the Andrijevica substation and to the Mojkovac substation; and (3) Improvement of the operational reliability of Perucica Hydropower Plant involving the installation of a new trash rack and new trash rack cleaning equipment, and supply of spare turbine runner(s) for Perucica Hydropower Plant.

1.6 Revised Components

There were no revisions of the components. Originally regional telecommunication links to Serbia and BiH were envisaged. Restructuring undertaken in April 2011 added a regional link to Kosovo and a few other internal links also, making use of the project savings.

1.7 Other significant changes

The implementing agency EPCG was legally unbundled and in that context responsibility to implement Components 1 and 2 devolved on Crnogorski Elektroprenosni Sistem AD (CGES) the new transmission company on the basis of an amended Financing Agreement. Minor changes included the extension of the closing date from March 31, 2012 to March 31, 2013 and later to September 30, 2013. Savings under the credit after contracting were reallocated partly to the regional telecommunication link to Kosovo and partly to the telecommunication links within the country.

2. Key Factors Affecting Implementation and Outcomes

2.1 Project Preparation, Design and Quality at Entry

Project preparation was based on EPCG's investment plans with a focus on facilitating security of supply and regional trade and followed the priorities indicated in them, consistent with the funds available. Project cost estimates were based on thumb rule costs, and allocations of funds for the components were tentative to be finalized after the preparation of designs, technical specifications and bidding.

Based on the lessons learnt from the earlier project financed by IDA[8], EPCG staff were given adequate training in the Bank procurement, financial management and reporting procedures. The technologies selected were kept simple and well within the capacity of EPCG. Supply and installation supervision contracting procedures were streamlined and standard bidding documents were used. EPCG was obliged to use consulting services for the design and technical specifications of the Telecommunications Component as a condition of disbursement.

At appraisal the Montenegro APL-3 Project was not expected to face any significant risk. Technologies chosen were well proven and perceived as risk-free. The sizes of the components were small and were well within the competence of EPCG to implement. The anticipated legal unbundling of EPCG was not expected to pose any risk to the Project. For the larger telecommunication component EPCG was obliged to use consulting support for design, technical specifications and the preparation of bid documents. Safeguard aspects such as environment and involuntary resettlement were not expected to create any risk, because of the very small lengths of the transmission lines and the very small amounts of lands involved. In retrospect, the very reasonable

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[8] Emergency Stabilization of Electricity Supply Project

assumption about land acquisition proved to be somewhat optimistic and the project incurred delays on this account. Some of the landowners did not accept the price and some claimed interference (through corona effect) with their manufacturing activities, and under the fair, but cumbersome procedures of the country it took an unexpectedly long time to resolve these issues.

2.2 Implementation

Implementation of the APL program Montenegro passed a new Energy Law in April 2010 to enable greater consistency with the EU energy directives. In terms of market liberalization all the non-residential consumers were already "eligible consumers" capable of choosing their own suppliers.[9] Under the new Energy Law all the residential consumers will become eligible consumers by 2015. Commencing from January 1, 2013, consumers directly receiving supplies from the transmission grid must have individual supply contracts and cannot be supplied on the basis of regulated tariffs.[10] Eligible consumers receiving electricity from the distribution networks however can be supplied on the basis of regulated tariff till they switch to a different supplier. As of now, none of them has switched his supplier.

In terms of sector unbundling, as noted earlier, the transmission company CGES was legally separated from EPCG in 2009. Subsequently the market operating function was separated from CGES and a separate fully state owned market operator Crnogorski Operator Tržišta Električne Energije (COTEE) was established to handle market operations, leaving CGES as a transmission system operator (TSO). However generation and distribution functions continue to remain bundled under EPCG. Further legal separation is expected within a year or two. In terms of private sector participation in the power sector, notable developments took place. An Italian company, A2A, acquired 43.71 percent of the equity shares of EPCG and also the management control of the company. The state retained 55 percent of the ownership. Similarly, another Italian company, Terna, acquired 22 percent of the ownership of CGES and the right to appoint two of the seven members of the Board and three top managers. Terna is also involved in a major project to connect Italy to Montenegro by a 415 km long 500 kV High Voltage Direct Current (HVDC) submarine cable, thus helping the further physical integration of the power systems of Montenegro and the EU.

The responsible institutions such as the ERA and COTEE have adopted most of the required regulations under the new Energy Law of 2010 within the deadlines set by the Law. ERA has fulfilled almost all of its tasks stipulated in the Energy Law as regards the legislative framework for a competitive market, mostly in 2012 and 2013. These include: (1) Rules for Functioning of Electricity Distribution System in September 2012; (2)

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[9] This was based on the notification to this effect by ERA in early 2008.

[10] There were only three such consumers: the aluminum smelter KAP, the steel works and the national railways. While KAP is under bankruptcy, the other two have concluded supply contracts. KAP during bankruptcy operates at one third of its capacity and has a contract with Montenegro Bonus, a new supplier licensed by ERA

Methodology for Setting Charges, Terms and Conditions for Connection to the Distribution Network; (3) Standard forms and documents for the registration of market participants and balance groups, as well as, operational rules and procedures relating to communication, complaint handling and other similar issues in the market; (4) Market Rules and Methodology for Setting Prices and Conditions for Provision of Ancillary and System Services and Balancing Services; and (5) Rules for Changing Electricity Tariffs, defining the procedures for setting provisional tariffs and the procedures for changing approved revenues and tariff rates during the tariff period. Rules for defining quality of services have been drafted and circulated for comments. Implementation of these rules and their strict enforcement are crucial for a market to develop. Wholesale traders do not need a license in Montenegro. Thus, several major regional traders in the EU market are registered as market participants in Montenegro. The country also hosts the Project Team Company in charge of establishing a SEE Coordinated Auction Office (PTC) which targets harmonization of the allocation and nomination rules for long and medium term transmission rights in the Region and executing multilateral coordinated auctions on all SEE borders as a regional one-stop-solution for end 2014.

The average tariff for electricity for all consumers in the country expressed in Euro cents/kWh has declined from 7.9 in 2007 to slightly less than 6.0 in 2011 and increased to slightly less than 8.0 in 2013. Current average tariff/kWh for all low voltage consumers is about 8.6 Euro cents (approximately equivalent to 11.8 US cents).
However, according to the EC secretariat, enforcement remains weak, tariffs still do not cover full supply costs, and transparency of network access needs to improve in Montenegro.[11]

Implementation of the Montenegro APL-3 Project: The credit effectiveness date was extended from November 26, 2007 to January 28, 2008, since the government needed additional time to execute the subsidiary Credit Agreement and produce legal opinions from EPCG. EPCG had met much earlier, the condition of disbursement by engaging the consulting firm KORONA of Slovenia (working with ELEM & ELGO of Serbia) as consultants for the preparation of design and technical specifications as well as bid documents for the Telecommunication Component (under its own financing) with terms of reference acceptable to the Bank. The mid-term review conducted in July 2009 found that EPCG had been legally unbundled and initiated action resulting in the amendments to the Financing Agreement executed in October 2009 to reflect the changed situation. It found that procurement was progressing satisfactorily and disbursements were running at about 30 percent. It suggested improvements to the EPCG-prepared-and-IDA-approved Land Acquisition Policy Framework (LAPF) from the reporting stand point. This was followed up in a later mission in July 2010 for further improvements.
The project was restructured twice. The first restructuring approved in April 2011 extended the closing date from March 31, 2012 to March 31, 2013 to allow for the delays

[11] This section is based on the Annual Implementation Report of the Energy Community secretariat (September 2013)

caused in resolving land acquisition issues in relation to substation extension and tower locations. It also allowed the savings under the credit to be applied to the telecommunications link to Kosovo and extend the internal communication links.

The second restructuring approved in January 2013 extended the closing date from March 31, 2013 to September 30, 2013 to accommodate further expected delays in the completion of the internal communication links and construction of the transmission line to Mojkovac.

In ten out of the twelve ISRs the project was rated "satisfactory" or "moderately satisfactory" in respect of both DO and IP. In the two ISRs dated September 9, 2012 and December 12, 2012 both DO and IP were rated "moderately unsatisfactory" because of the long delays without much effective action in respect of the Mojkoac substation and related transmission lines despite the first restructuring involving the first extension of the credit closing date. Once serious action was initiated and pursued the rating was restored to "modestly satisfactory' status.

The project was implemented with a delay of 18 months and the credit was closed on Sept 30, 2013. Final disbursements were made on October 8, 2013 and the credit account was closed on December 31, 2013, canceling the unused amount of XDR 181,920.34 (or about 3 percent of the approved credit). All items of the works under the Project have been completed within 2013 and the facilities are operational. With respect to Component 1, the telecommunication link to Kosovo was completed up to the border between Montenegro and Kosovo and the portion in Kosovo will be completed by Kosovo under KfW financing in 2014. With respect to Component 2, the 110 kV line has been completed and the Substation at Andrijevica has been operational since September 2011. The 220 kV transmission line to Mojkovac substation was delayed by unexpected land acquisition issues, but the line has been completed and the substation was expanded to include an addition transformer bay and started trial operations in August 2013. With respect to Component 3, replacement of trash rack and trash rack cleaning equipment were completed by the fourth quarter of 2009, while the replacement of the turbine runner was done in September 2011. The entire project was completed within the budget, but with a delay of 18 months, which was attributable to delay in achieving effectiveness of the credit, and land acquisition and procurement related issues.

2.3 Monitoring and Evaluation (M&E) Design, Implementation and Utilization

The EC program was being monitored and coordinated by the Ministerial Council, Permanent High Level Group, task forces and forums of the EC effectively supported by the EC secretariat. The secretariat periodically evaluates the country performance in relation to its obligations under the EC treaty and reports to the above bodies.

Implementation of the Montenegro APL-3 Project was monitored by the Bank through quarterly progress reports, audited project expenditure statements and audited company financial statements of EPCG and CGES. Several implementation support missions and a mid-term review, procurement reviews, environment and safeguards reviews and FM reviews, enabled adequate monitoring of the project implementation.

The appraisal document included an annex for Results Framework and Monitoring, which specified the indicators for the PDO, as well as intermediate and final results targets for the indicators. Quantitative targets were used for components 2 and 3, while qualitative targets were indicated for component 1. Periodic reviews during supervision missions were with reference to these time-bound targets. The specified results indicators turned to be difficult to monitor.

2.4 Safeguard and Fiduciary Compliance

The Project was classified as Category B in terms of environmental aspects, in view of its modest impacts. The environmental management plans (EMPs) to minimize and mitigate adverse impacts were prepared for Components 2 and 3, translated in local language, adequately publicized and consultations were carried out before appraisal. Supervision missions and missions by environment specialists noted that the EMPs were made part of the contracts and that compliance with the EMPs by contractors was enforced by the implementing agencies. They also noted that in respect of some of the installation contracts financed exclusively by EPCG the EMPs had not been included and pursued appropriate remedial measures. In respect of Component 1, the missions noted that all parts with possible environmental impacts had been completed and there were no issues. In respect of Andrijevica substation and 110 kV line under Component 2, no issues were outstanding and EMP had been followed. In respect of Mojkovac substation and line, site reviews confirmed compliance with the EMP and other previously agreed measures. In respect of Component 3, compliance with EMP had already been achieved.

In respect of land acquisition, lands needed were sought to be purchased mostly at commercial prices by the implementing agency under the EPCG-made-and-IDA-approved LAPF. Bank suggested improvements on reporting in this regard were followed. Only 36 parties were affected by the land acquisition proceedings, which were proceeding smoothly albeit with delays. Legal proceedings were initiated in those cases where the agreements on the land purchase had not been reached. One owner near the Mojkovac substation did not agree with the valuation and also claimed that the overhead transmission line could adversely affect his manufacturing operations. This led to delays of several months before these issues could be resolved within the legal framework of Montenegro to adjudicate on such issues. The Bank missions were alert to the possible mishandling of these issues and took reasonable care to ensure that all formalities were observed and to have the reporting defects cured.

Review missions supported by financial management specialists of the Bank Group found the financial management arrangements for the project (covering such aspects as budgeting, accounting, internal controls, funds flow, financial reporting, and project audit) functioned satisfactorily. Payments exceeding Euro 50,000 in value were on the basis of direct payments to suppliers by IDA at the request of EPCG/CGES, and payments below that value were made by the utilities and were later reimbursed by IDA. The project accounts statements audited by external auditors acceptable to IDA were received periodically and found to be satisfactory. Transactions review was carried out during each of the on-site supervision visits and no weaknesses were identified with respect to existence and flow of documents, authorized signatures and approvals, segregation of duties and application of eligible percentages. Adequate system of internal controls was developed for the project implementation, and transactions review has not identified any omissions in application of internal controls and procedures in practice.

Audited financial statements of EPCG were received for the years 2008-2012 and found by the financial management group of the Bank acceptable. Similarly the audited financial statements of CGES were received for the years 2010-2012 and found acceptable. Some of these audits had a qualified opinion and utility managements were pursuing actions for corrective actions. It was adjudged that these qualifications did not adversely affect the financial management of the project. However these financial statements were not reviewed by any financial analyst from the point of view of compliance with the two financial covenants relating to the collection ratio and self-financing ratio. The ICR mission obtained information regarding the compliance with these ratios for the period 2007-2012 and the results are discussed in Annex 3

Procurement arrangements were relatively simple. IDA finance was applied to the cost of supply of goods (excluding taxes and duties), and the needed installation supervision, while all installation contracts as well as taxes and duties (such as VAT) were financed exclusively with borrower funds. The consulting services contract for the preparation of designs, specification and bid documents was also financed fully by the borrower funds.[12] Procurement reviews indicated overall compliance with agreed IDA procurement methods and procedures, and despite certain delays, the arrangements proved satisfactory.

2.5 Post-completion Operation/Next Phase

Montenegro has to continue its efforts to comply fully with the letter and spirit of the EU energy directives and its own new Energy Law of 2010. The independence of the ERA has to become substantive and its ability to enforce its rulings should be fully enabled and supported. The country has to substantially improve the transparency of the network access and capacity auctioning and allocation system.

Distribution system losses have to be sharply reduced from the current level of 19 percent to the allowed level of 9% (basically by eliminating non-technical losses) and collection levels need to improve to the industry best practice levels. With the greater role for the private sector in the management of EPCG and CGES, one may expect improvement in these commercial aspects of utility operation. Progress is being achieved in the installation of smart meters and automatic remote meter reading. The aluminum smelter KAP had been the biggest problem of the power sector and it is now under bankruptcy proceedings, operating at one third of its capacity and purchasing power on the basis of contracts with Montenegro Bonus- a newly licensed supplier. Given its impact on the national employment, production and exports, it is not an easy problem to resolve. However, if it survives, it must be on the basis of its willingness, ability and discipline to

[12] Borrower also financed parts of equipment supply which could not be accommodated under IDA credit

contract for its electricity supplies from any source in the regional/European market and be able to pay fully and punctually the agreed power price. When KAP related issues are suitably resolved, Montenegro should be able to restructure its tariffs for its regulated tariff consumers to recover supply costs and provide relief to the vulnerable among the power consumers as the other two large consumers, the steel works and the national railways have agreed to, and are actually receiving supplies on the basis of contracts with suppliers.

The telecommunication elements of the Montenegrin power system already linked to Serbia and BiH will soon be linked to Kosovo also, enabling better communication for the more efficient national and regional operations, strengthening the regional integration objective. These facilities will be operated by CGES as per the industry practice. Similarly the transmission and substation facilities under the project are being operated by CGES as a part of its normal operations. The generation facility improvements in the Perucica HPP are being operated by EPCG. Both EPCG and CGES have the institutional capability for the operation and maintenance of the project facilities. There is no formal follow up investments for the project. IDA is already assisting the country in energy use efficiency through an ongoing operation.

3. Assessment of Outcomes

3.1 Relevance of Objectives, Design and Implementation

Creation of a regional energy market and its eventual integration with the EU energy market is an ongoing process in which considerable regional energy trade is taking place already. Creation of conditions for this trade to take place on a competitive basis continues to be a relevant objective. The project objectives of (a) facilitating regional trade integration through the establishment of a modern and efficient telecommunication system, (b) reducing system outages by reinforcing transmission links and (c) improving the HPP reliability through rehabilitation continue to be relevant for the efficient operation of the sector and reliability of supply. The program and project objectives are also consistent with one of the two priority objectives of the current Country Partnership Strategy (FY 2011-14), namely to strengthen institutions and competitiveness in line with EU accession requirements. The relevance of the objectives of the program and the project is thus rated *high*

The Project design was simple and straightforward consistent with the capabilities of the utilities and the availability of resources. The borrower and the utilities continued to display a high level of dedication to implement the project properly till the end. However, the design of the key indicators and their end targets are considered unsatisfactory, making meaningful monitoring and evaluation difficult. On account of this shortcoming the Project design is rated *substantial*.

3.2 Achievement of Project Development Objectives

The emergence of the regional energy market and its integration with the EU market is an ongoing and long term process and the achievement of the development objectives of the APL-3 project would clearly support the overall program objective. Under the EC treaty all non-residential consumers were to be liberalized (that is made eligible to choose their own electricity supplier) by July 1, 2008 (or such other date agreed to under derogations and subsequent modifications, if any) and all consumers were to be liberalized by January 1, 2015. In terms of the Energy Law of 2010, all non-household customers in Montenegro were already liberalized and free to choose their supplier [13], and all consumers will become eligible by January 1, 2015. Thus liberalization targets are being met satisfactorily. In 2012, eligible non-household consumers had a share of 8.8 percent in the total number of consumers, but in terms of energy consumption had a share of 62 percent in the total consumption. Only three of them were supplied directly from the transmission grid and were obliged to have supply contracts with their chosen supplier (see section 2.5 above). Thus the achievement of this program objective is rated *high.*[14]

The project objective of improving the efficiency and reliability of the power system in Montenegro, through better supply security and closer integration into the regional markets is considered partially achieved. For the Telecommunication Component no quantitative indicators were used in the PAD. In terms of the project objectives, an improved, modern and efficient telecommunication system had been fully established, which has strengthened considerably Montenegro's ability to operate its own system efficiently and to participate in the regional market and has thus facilitated closer regional market integration. The achievement of the outcome with respect to this Component is rated *high*.

Quantitative indicators were provided for the objectives of the other two components, and the results are discussed below in relation to those targets. In relation to Andrijevica and Mojkovac substations (under Component 2) outage data are presented in Table 1 below.

Table 1: Indicator Statistics for Component 2.

Year	**Andrijevica substation**			**Mojkovac substation**		
	No. of outages	**Total duration in minutes**	**Unserved energy MWh**	**No. of outages**	**Total duration in minutes**	**Unserved energy MWh**
2005	31	3719	371	16	1693	291
2006	44	4247	311	9	1169	103
2007	42	6798	485	13	2157	183
2008	26	1558	113	16	478	50
2009	22	1853	134	5	59	5
2010	23	757	54	5	588	39
2011	31	6073	414	9	445	43
2012	5	921	59	11	3291	385
2013	5	96	5	16	846	73

Note: The data for 2005 is from PAD; the data for the remaining years were reported by CGES in 2013. There was no outage and no unserved energy in respect of Andrijevica since March 31, 2013

[13] The ERA had issued decisions in early 2008 making all non-residential consumers eligible consumers with effect from July 1, 2008.
[14] The ratings in Sections 3.1, 3.2 and 3.3 follow a four point scale : *Negligible, Modest, Substantial or High*

The PAD had stipulated a 50% reduction in the unserved energy by 2010, but a draft report by QAG (April 2010) believed that the number of outages rather than the unserved energy should be the appropriate indicator and suggested that end targets (for 2012) could be 17 and 8 outages for the above two substations compared to 31 and 16 outages they had in 2005. With respect to Andrijevica substation the target appears to have been achieved both in terms of number of outages and in terms of unserved energy. With respect to Mojkovac where the reinforced substation entered trial operations as late as August 1, 2013, the numbers of the years up to 2012 (and perhaps 2013 as well) are not relevant. We will have to look at the numbers for 2014 to verify whether the targets would be achieved, even though belatedly. Such an achievement of the target appears likely. Based on these findings the achievement of outcome in respect of this Component is rated *substantial*.

With respect to Component 3 the indicator chosen in the PAD was a 75 percent reduction in the annual O&M expenses of the trash rack system of HPP Perucica and a 20 percent reduction in the O&M expenses relating to turbine rings by 2010. The QAG considered these targets inappropriate and suggested that after the turbine runners' replacement, the down time of HPP Perucica should come down by 20 percent.

EPCG staff estimate that in an average hydrological year, the replacement of the trash rack and the cleaning system would save an amount of Euro 105,000 in their annual maintenance costs Time series O&M cost data for maintenance of the individual pieces of equipment to further elucidate this estimate in relation to the key indicator are not available. In 2010, which was a year of huge water inflows, the trash rack and the cleaning system operated without any stoppage and with a reliability index of 99.79 percent and an availability index of 89.84 percent clearly evidencing the wisdom of the replacement of the old systems. From the plant availability data given in Annex 10, it appears reasonable to attribute some portion of the increased plant availability since 2010 to the replacement of the trash rack system in 2009.

Regarding the replacement of the turbine runner, it is necessary to keep in mind that the plant has seven sets of turbines and associated generating units, served by three penstocks. EPCG has already purchased and replaced four turbine runners during 2007-2013 besides the one financed under IDA credit. Two more runners are under procurement. Two of the additional runners are financed by EIB and the rest is financed by EPCG. EPCG estimates that it spent annually a sum of Euros 21,500 during 2010-2013 for inspecting and repairing damages to all runners in the Hydropower station. In addition, EPCG has done extensive rehabilitation works on this hydropower station facilities worth over Euro 20 million. Also clearly the replacement of the trash rack system has contributed to the increased plant availability and production. Thus the improvement in the plant availability is a result of all these improvements and cannot be attributed exclusively to any one of them. From the annual generation data from this station as well as the plant availability data for the various turbines provided in Annex 10, it is clear that the availability of the generating units improved after the replacement of runners and also after the completion of trash rack work in 2009. However, actual generation depends on the demand profile and water flows into the reservoir apart from the individual availability of the generating units of the HPP.

In the light of the above analysis it is concluded that though the substance the project objective for components 3 has been achieved, its clear demonstration in terms of the indicators in the PAD had not been possible. On account of this moderate shortcoming, the achievement is considered *substantial*.

3.3 Efficiency
(Net Present Value/Economic Rate of Return, cost effectiveness, e.g., unit rate norms, least cost, and comparisons; and Financial Rate of Return)

Component 1, Telecommunication System Development (with 67 percent of the total actual project cost) has enabled the more efficient operation of the national system, by itself and as an integral part of the regional electricity market. Information flows on real time system conditions have enabled greater reliability of the systems and supplies. More detailed descriptions of the benefits are given in Annex 3 and Annex 7. However, it is not possible to meaningfully quantify the benefits of the telecommunication system development nor would it be correct or logical to attribute the benefits exclusively to the telecommunication investment alone. The benefits such as more efficient operation and increased reliability are attributable to several factors in addition to the telecommunication improvements. Thus the lack of exclusive cause and effect relationship renders quantitative cost-benefit analysis impossible. The PAD also expressed the same view.[15] It is needed and justified in terms of it enabling the more efficient operation of the Montenegrin system (both by itself and in the regional market) and the need for Montenegrin system to be linked at least to two adjoining systems in the regional market in order to comply with the requirements of the former UCTE and the present ENTSO-E of Europe. The telecommunication system has rendered the Montenegrin system more closely integrated with the regional market. Through the use of experienced consultants and the use of ICB, the Component has been completed in a least cost manner leading to the acquisition of a lot more of equipment than originally envisaged using the allocated amounts. The efficiency of this Component is rated *substantial*.

The PAD has attempted to quantify the benefits of transmission improvements (Component 2 with 24 percent of the total cost) and compute internal rates of return. However the soundness of the methodology is open to question. The benefits of the

[15] The PAD stated “implementation of the telecommunications system (Component 1) will be necessary to integrate the Montenegrin electricity market into the regional markets and to realize the economic benefits of accessing regional supply resources to meet its growing demand. These benefits are significant for Montenegro in terms of cost and security of electricity supply; however it would be hard to quantify these benefits which are directly attributed to the telecommunications system. Therefore, no Economic Rate of Return was calculated for this subproject”

transmission improvements have been assumed to be a reduction in the forced outages at the two substations (which is logical) leading to a reduction of the unserved energy in the areas served by the two substations. The later portion of the assumption of relationship between the reduced outages and reduced unserved energy is however questionable as all unserved energy reduction cannot be exclusively attributed to a reduction in substation outages. Further the assumptions regarding the quantum of reduction of unserved energy turned out to be unrealistic. The variations between PAD assumptions and actuals regarding unserved energy are wide, nonlinear and unpredictable indicating the lack of exclusive causative relationship among the three variables, namely transmission improvement, number of outages and unserved energy (Annex 3). Further it is not possible to forecast or project meaningfully weather related capacity and system outages.

Reduction in transmission or substation outages is only one of the several causes of reduction in unserved energy. It is for this reason the QAG review of 2010 also recommended that the PDO indicator should be in terms of reduction in the number of outages and not in terms of unserved energy. The transmission improvements are justified in terms of technical necessity to provide the needed redundancy to conform to the N-1 contingency outage criterion and to make the system more reliable in those parts of the grid. Thus the achievement of efficiency of Component 2 is rated *substantial*.

The PAD has also attempted to quantify the benefits of Perucica HPP rehabilitation (component 3 with 9 percent of the total cost) and compute IRRs. It is not safe to operate HPPs without trash racks. Thus old and worn out trash racks must be replaced out of sheer technical necessity. When trash rack cleaning mechanism is inefficient and clogs the trash track, differentials in the head develop reducing the energy generation capability. According to the literature, such losses in energy production capability could be as high as 20 to 25 percent of the designed output. Following the methodology of PAD, an EIRR calculation taking into account the actual cost of rehabilitation (including new trash rack, trash rack cleaning system and the turbine runner) excluding VAT, and assuming the energy losses prevented by them to be about 10 percent of the average annual output of Perucica HPP (2005-2012) and pricing the energy at 4.5 euro cents/kWh the EIRR is as high as 190 percent. Even when the energy loss avoided is assumed to be 0.5 percent of the average annual energy, the EIRR remains robust at 19 percent (Annex 3). The efficiency of Component 3 is, thus, rated *high*.

3.4 Justification of Overall Outcome Rating

Rating: Moderately Satisfactory
The relevance of the objectives of the program and the project is *high*. The shortcoming of the design was in the specification of key indicators of the results leading to the design being rated *substantial*. The achievement of two of the four PDOs is rated *high* and the other two are rated *substantial*. Efficiency could not be quantitatively estimated for a major portion of the investment and is therefore rated *substantial*. As a result the overall outcome rating is assessed as moderately satisfactory.

3.5 Overarching Themes, Other Outcomes and Impacts

(a) Poverty Impacts, Gender Aspects, and Social Development
Not applicable
(b) Institutional Change/Strengthening
As discussed earlier, major changes such as enactment of the new Energy Law, sector unbundling and preparation of the sector to function in a competitive regional market are taking place in the context of Montenegro signing and abiding by the *EC treaty*, supported by the APL Program of the Bank Group. The APL-3 Montenegro project played its role in this process. EPCG was unbundled and underwent major institutional changes during the implementation period of the project. Significant private sector participation occurred both in EPCG and in CGES with management changes. The new institution COTEE legally separated from CGES may need strengthening to enable market development and cope with increasing complexities such a development entails.

(c) Other Unintended Outcomes and Impacts (positive or negative)
None

3.6 Summary of Findings of Beneficiary Survey and/or Stakeholder Workshops
None

4. Assessment of Risk to Development Outcome
Rating: Low
In respect of the program DO of achieving a liberalized competitive regional market, the risk to the achievement of full liberalization is low, as the liberalization provision is incorporated in the new Energy Law (2010). Regional electricity market is functioning, and while its transformation as a fully competitive market as envisaged in the *EC Treaty* might take a longer time than originally planned, the risk of that not happening is considered low.

In respect of the DOs of the project, the draft QAG report of 2010 considered the risk to be moderate, because of the delays experienced in land acquisition for component 2 at that time. As of now the project is almost complete and operational and sustainable institutional arrangements are in place to operate the facilities efficiently. Thus the risk to the DOs of the project is considered low or negligible

5. Assessment of Bank and Borrower Performance

5.1 Bank Performance
(a) Bank Performance in Ensuring Quality at Entry

Rating: Moderately Satisfactory.

A QER meeting held on March 16, 2006 rated the quality at entry satisfactory. A draft report of the QAG (April 2010) assessed the quality of design and the quality of Bank supervision satisfactory. It further rated the likelihood of the DOs being achieved as likely and the risks to the DOs as moderate. The ICR mission notes that the presentation of the cost estimate for the project in the various sections of the PAD is somewhat inconsistent and confusing. It is perhaps the result of the two to three year period of project appraisal and the adoption of the exchange rate prevailing on the date of the final PAD, while actual calculations were based on rates prevailing earlier. Despite the prolonged period of project preparation and appraisal the cost estimates were probably based on tentative thumb rule costs leading to substantial savings later allocated to finance additional items. The presentation of the Components, and Components to be financed under the Bank were also unclear and confusing. The basic rationale for the economic analysis is questionable. Similarly the rationale for PDO indicators is also questionable. For these reasons the ICR mission assesses the Bank performance in ensuring quality at entry to be moderately satisfactory.[16]

(b) Quality of Supervision
(including of fiduciary and safeguards policies)
Rating: Moderately Satisfactory

During the project implementation phase there were three Task team leaders, who carried out adequately frequent implementation support missions. There was also a midterm review mission. The financial management specialists and environmental specialists either participated in these missions or carried out separate missions. Procedural lapses such as the EMPs not being attached to the bidding documents of the construction contracts financed by the utility and in land acquisition were identified and remedial measured were suggested. These missions also enabled the two restructurings of the credit to enable fuller utilization of the approved credit. The PIU considered the missions to have been helpful in solving problems as they arose. However, compliance with the two financial covenants relating to the SFR (of EPCG and CGES) and Collection Ratio of EPCG were never reviewed by the supervision missions or by any financial analyst in the office. This is perhaps attributable to the lack of adequate number of financial analysts in the division. Further, the QAG review of April 2010 actually suggested revised indicators for Components and 2 and 3 which do not appear to have been acted upon. The opportunity to correct for this deficiency in results monitoring arrangements while restructuring the Credit (in 2011) was missed, thus rendering the Project evaluation difficult and frustrating.

(c) Justification of Rating for Overall Bank Performance
Rating: Moderately Satisfactory

5.2 Borrower Performance
(a) Government Performance
Rating: Moderately Satisfactory.
Though the government needed additional time for making the credit effective, it remained committed to the project and the *EC treaty* obligations and enabled the

[16] It appears that there was another QAG review in FY2008; but no records were available in the project portal.

enactment of the new Energy Law, the unbundling of the sector, and participation of the private investment and management in the power sector. However, as noted by the Annual Implementation Review (2013) of the EC Secretariat, distribution function still remains to be unbundled from EPCG, tariffs lag behind costs, and the ERA lacks in reality the power to enforce its decisions. Further, the handling of the undoubtedly complex and difficult problem of the aluminum smelter KAP created major problems to the power sector. While the government had been undoubtedly helpful in resolving the immediate problem, a long-term resolution is still awaited.

(b) Implementing Agency or Agencies Performance
Rating: Moderately Satisfactory

EPCG and CGES maintained a joint PIU staffed with competent and experienced professionals and maintained the continuity of its members and staff despite their legal separation and enabled smooth project implementation. However after the legal separation of the two utilities, the Bank had to spend a great deal of time and effort to formally enable such a continuation of the PIU. The utilities provided quarterly progress reports, the audit reports for the project expenses, and their audited financial statements. Securing them often involved considerable effort on the part of the Bank in reminding and follow up. They implemented the project with diligence and mostly in compliance of the various Bank guidelines. They showed willingness to undertake remedial actions when unintended lapses occurred due to misunderstanding and were pointed out to them. However their responses for the request of regular data on the PDO indicators could have been more consistent and meaningful. Further the Bank staff found it often very difficult and time consuming to get meaningful responses from the utilities on issues raised.

(c) Justification of Rating for Overall Borrower Performance
Rating: Moderately satisfactory

6. Lessons Learned

The positive lesson is that this is another successful Project, which proves that the Bank financing of a well-chosen and relevant Project, however small, helps to support the overall APL Program objective of improving the national power markets and nudging them towards regional integration and facilitating the evolution of a competitive regional power market.

However there are some lessons, which the Bank should keep in view. These include:

- Formulating projects on the basis of realistic cost estimates after carrying out the design and technical specifications and bidding to avoid needless uncertainties;
- Specifying key indicators which are practical, logical and measurable targets, in the absence of which monitoring and evaluation become difficult;
- Utilizing the restructuring opportunities to remedy such omissions;
- Strengthening the supervision missions with adequate backstopping by qualified financial analysts to evaluate the financial condition of the implementing agencies in relation to the financial covenants.

7. Comments on Issues Raised by Borrower/Implementing Agencies/Partners

(a) Borrower/implementing agencies
No special issues were raised

(b) Cofinanciers
None

(c) Other partners and stakeholders
None

Annex 1. Project Costs and Financing

(a) Project Cost by Component (in Euro and USD Million equivalent)

Components	Appraisal Estimate Euro million	Actual / Latest estimate Euro million	Percentage of Appraisal
Component 1: Telecommunication System Development			
Phase 1: Regional link to Serbia	2.64		
Phase 2: Regional link to BiH	3.70		
Phase 3: Links within the country	4.48		
subtotal	6.34	8.11	128 %
Component 2: Transmission Network Reinforcement			
Andrijevica 110/35 kV substation connection	1.22	1.80	
Mojkovac 220/110/35 kV substation connection	1.44	2.20	
subtotal	2.66	4.00	150 %
Component 3: : HPP Perucica Operation Reliability Improvement			
Replacement of Trash Rack and Trash Rack cleaning equipment	0.83		
Supply of spare turbine runners	0.83		
Subtotal	1.66	1.02	61 %
Base cost	10.66	13.13	
Physical and price contingency	1.07	-	
Unallocated	1.60	-	
Total Project cost in Euro million	13.33	13.13	99 %
Exchange rate for Euro in US dollars	\$ 1.2378 (at appraisal)	\$1.3522 (Sep 30, 2013)	
Total Project cost in US\$ million	16.50	17.75	108 %

Note 1: Subtotal for Component 1 in the PAD excludes the cost of Phase 3 which was left as financing gap to be met partly from possible savings after bidding within the ceiling of IDA funding of XDR 6.0 m (or \$ 9.0 m). However under the "actuals" column, the subtotal includes the cost of all three phases and also the additional link to Kosovo, as well as the cost of consulting services for Component 1 paid for by EPCG.

Note 2: Actual expenses in column 3 above include actual expenses as of the Mid-January 2014 and expected payments for work already done.

Note 3: The exchange rate of \$1.2942 to a Euro shown in the PAD Annex 5 is apparently a mistake, as the project preparation and appraisal took place in late 2005 and reached negotiations stage in April 2006 and was later renegotiated in May 2007. Only at the exchange rate shown in the table above can the various cost and financing related numbers in the PAD can be reconciled.

Note 4: Component and total costs include VAT and import duties payable by EPCG.

Note 5: Tables (a) and (b) differ slightly due to rounding

(b) Financing

(b) (i) Financing plan (Euro million)

Source of Funds	Co-financing	Appraisal	Actual	Percentage of Appraisal
IDA	0	7.27	6.60	91%
Borrower	0	6.06	6.53	108%
Total	0	13.33	13.13	99%

(b) (ii) Financing Plan (US$ million)

Source of Funds	Co-financing	Appraisal	Actual	Percentage of Appraisal
IDA	0	9.0	8.92	99%
Borrower	0	7.5	8.83	117%
Total	0	16.5	17.75	108%

Note: The actuals in Table b (ii) above is based on the exchange rate of Euro 1 = US$ 1.3522 prevailing on the closing date September 30, 2014. If the original exchange rate of Euro 1= US$ 1.2378 is used the total actual cost is $16.25 suggesting a cost underrun. Thus the slight cost overrun seen in Table b (ii) above is caused by variations in exchange rate. Further the project as completed included a lot more of equipment and works than was included in the appraisal estimate.

Annex 2. Outputs by Component

Component	Status	Output
1. Telecommunication System Development		
(a) Regional link to Serbia	About 150 km of Optical ground wire installed over the 400 kV lines Podgorica 2 - Ribarevine and Ribarevine - *SS* Pljevlja 2 with associated equipment. Telecom link to Serbia is established.	About 541 Km of OPGW were installed on 400 kV, 220 kV, and 110 kV lines and telecom equipment has been installed at 26 nodes in the transmission system within the scope of the APL-3 Project. In addition OPGW was installed on 93 km of 400 kV, 220 kV and 110 kV lines under financing by EPCG. In addition the Remote Fiber Test System has been installed and it is to detect fiber faults or degradation before they impact on the network. The Remote Fiber Test System shall monitor the fiber network 24 hours a day, seven days a week. The telecom system covers fully the Montenegrin system and its links to BiH, Serbia and Kosovo.
(b) Regional link to BiH	About 230 km of OPGW installed on the 400 kV, 220 kV and 110 kV links between Montenegro and BiH along with associated equipment. Telecom links with BiH established. In addition OPGW was installed on the 400 kV line from Ribarevine SS to Kosovo border. When Kosovo completes its portion this telecom link will be operational	
(c) Internal telecommunication links	Two telecom rings at the 110 kV level from the National Load dispatch center at Podgorica to the various substations in the country	
2. Transmission Network Reinforcement		
(a) Link to Andrijevica 110 kV Substation	Completed. Operational since September 2011	A second two km of 110 kV link from the grid to this substation along with associated substation equipment to improve its reliability.
(b) Links to Mojkovac 220/110 kV substation	Completed and Trial operations started on Aug 1, 2013	A second 2.5 km long 220 kV line with associated extension of the substation to accommodate an addition transformer bay and associated equipment to improve the reliability of this key substation
3. HPP Perucica Reliability Improvement		
(a) Replacement of Trash Rack and Trash Rack cleaning equipment	New Trash Rack was procured and installed by September 2009. New trash rack cleaning equipment was also installed and became operational by end 2009	Installation of new equipment has eliminated stoppages in operation of HPP Perucica caused by operation failures of the old Cleaning Machine at the Vrtac bottom outlet.
(b) Provision of spare runners for the Turbines	Turbine runner for Unit 7A was procured and installed by September 2011	Turbine runners for units 3 A, 3B, 4A, 4B, 6A, and 7B were replaced either under EPCG financing or other external financing during 2004-2011.

Annex 3. Economic and Financial Analysis

(including assumptions in the analysis)

1. Economic Analysis

It is not possible to meaningfully quantify the benefits of the telecommunication system development (Component 1 with 67 percent of the total actual project cost). PAD also expressed the same view. It is needed and justified in terms of it enabling the more efficient operation of the Montenegrin power system (both by itself and in the regional market) and the need for Montenegrin system to be linked at least to two adjoining systems in the regional market in order to comply with the requirements of the former UCTE and the present ENTSO-E of Europe. The development of modern telecommunication system was the subproject of paramount importance for the integration of electricity market in Montenegro with regional markets.

The new telecommunication network enables CGES to fulfill communication requirements of dispatching, measuring and operation of high voltage network and to ensure easier communication among the main CGES services, with the aim of improving financial management and administration. The new telecommunication network interconnects the National Dispatching Centre of Montenegro and dispatching centers of neighboring countries and allows CGES to fulfill UCTE requirements (as its member) stipulating that each member must have at least two "point to point" independent telecommunication connections with other two transmission system operators in the region.

It enables coordination of operations of regional markets, improvement of data exchanges between market participants, and supports timely planning and implementation of bilateral agreements and electricity trade plans in future aimed at the energy security of the country

It establishes connection between CGES and ENTSO-e system through the Electronic Highway Computer Network. It fulfills communication requirements of the European Network of Transmission System Operators of Electricity (ENTSO-E Policy 6: Communication Infrastructure), namely to: (a) ensure interconnection with neighboring electric power utilities; (b) satisfy the needs for communication within technical and business management system; (c) provide capacity for potential provision of a wide range of telecommunication services on the telecommunication market; and (d) ensure cost savings from decreased use of capacity leased from fixed and mobile telephony operators.

The telecommunication system has rendered the Montenegrin system more closely integrated with the regional market. Through the use of experienced consultants and the use of ICB, the component has been completed in a least cost manner leading to the acquisition of a lot more of the equipment than originally envisaged with greater reliability and more improved technology.

The PAD has attempted to quantify the benefits of transmission improvements (Component 2 with 24 percent of the total cost) and compute internal rates of return. However the soundness of the methodology is open to question. The benefits of the transmission improvements have been assumed to be a reduction in the forced outages at the two substations (which is logical) leading to a reduction of the unserved energy in the areas served by the two substations. The later portion of the assumption of relationship between the reduced outages and reduced unserved energy is however questionable as all unserved energy reduction cannot be exclusively attributed to a reduction in substation outages. Further the assumptions regarding the quantum of reduction of unserved energy turned out to be heroic. Thus in respect of Andrijevica substation the PAD assumed that the unserved energy would increase from 372 MWh in 2005 to 809.9 MWh at an annual rate of 20 percent and after the commissioning of the proposed transmission project would increase at the rate of 5 percent per year to 893 MWh in 2012. The actual historical data provided by CGES indicates that the unserved energy moved from 372 MWh in 2005 to 59 MWh in 2012 in an erratic and unpredictable manner. Similarly in respect of Mojkovac substation area also the variations between PAD assumptions and actuals are wide, nonlinear and unpredictable indicating the lack of exclusive causative relationship among the three variables, namely transmission improvement, number of outages and unserved energy (table A3.1). Thus the PAD analysis cannot be considered sound.

Table: A3.1: Comparison between actual unserved energy and those assumed in the PAD

Year	**Andrijevica substation area**		**Mojkovac substation area**	
	Unserved energy assumed in PAD (MWh)	**Unserved energy Actual (MWh)**	**Unserved energy assumed in PAD (MWh)**	**Unserved energy Actual (MWh)**
2005	372.0	371	295.0	291
2006	446.4	311	354.0	103
2007	535.7	485	424.8	183
2008	642.8	113	509.8	50
2009	771.4	134	611.7	5
2010	809.9	54	734.1	39
2011	850.4	414	770.8	43
2012	893.0	59	809.3	385

Reduction in outages is only one of the several causes of reduction in unserved energy. It is for this reason the QAG review of 2010 also recommended that the PDO indicator should be in terms of reduction in the number of outages and not in terms of unserved energy. The transmission improvements are justified in terms of technical necessity to provide the needed redundancy to conform to the N-1 contingency outage criterion and to make the system more reliable in those parts of the grid. Meaningful quantitative analysis is not considered possible.

The PAD has also attempted to quantify the benefits of Perucica HPP rehabilitation (Component 3 with 9 percent of the total cost) and compute IRRs. It is not safe to operate HPPs without trash racks as trash will destroy the turbines and related equipment. Thus old and worn out trash racks must be replaced out of sheer technical necessity. When trash rack cleaning mechanism is inefficient and trash clogs the trash track, differentials in the head develop reducing the energy generation capability of the plant. According to the literature, such losses in energy production capability could be as high as 20 to 25 percent of the designed output. Given the energy prices and the relatively low capital cost of trash rack cleaning systems such investments tend to have pay back periods as low as three months and IRRs in three digits. Following the methodology of PAD, an EIRR calculation taking into account the actual cost of rehabilitation (including new trash rack, trash rack cleaning system and the turbine rings) excluding VAT, and assuming the energy losses prevented by them to be about 10 percent of the average annual output of Perucica HPP (averaged over the eight year period 2005-2012) and pricing the energy at 4.5 euro cents/kWh (same as the number used in the PAD and still a conservative valid number in the Balkans energy market) the EIRR is as high as 190 percent. Even when the energy loss avoided is assumed to be 0.5 percent of the average annual energy, the EIRR remains at 19 percent. However the limitations of this type of analysis must be borne in mind. The improvements only enhance the plant availability or reduce the plant down-time and may not necessarily result in additional generation, as it will depend on the water flows and demand profile.

2. Financial Analysis

Financial performance of EPCG 2008-2012

During 2007-2012, EPCG has been making losses (operational income before taxes) every year except in 2009 and 2010. It operates a system with a high hydro dependency with the hydro generation share in the total varying from 45% to 77% depending on the water flows. Not surprisingly in 2009 and 2010 the share of hydro generation in the total were highest at 77% and 68%. The other key reasons for the financial problems of EPCG are: (a) high levels of imports of power at prices much higher than the cost of domestic generation; (b) high share of unprofitable sales to direct consumers and especially to KAP which has accumulated huge arrears (c) high levels of distribution losses, and (d) continuing collections problems. The gross trade receivables in 2012 was equal to the value of more than one year sales revenue and every year large provisions are being made for doubtful and uncollectible debts. The net receivables after substantial provisioning in 2012 for bad and uncollectible debts were equal to about sales of 5.22 months. By 2012, the electricity company has emerged as the second largest tax debtor to the government, largely because KAP has accumulated payment arrears towards the electricity company equivalent to 1.8 percent of GDP.

The assets of EPCG are financed mostly by equity as the debt/ (debt + equity) ratio was at very low level of about 7% even by 2012. The equity is being gradually eroded (by the accumulated losses) from Euro 933.5 m in 2007 to Euro 853.4 m by 2012. Its transmission assets were transferred to CGES in 2009 and the remaining fixed assets were revalued in 2010. This added some revaluation surplus to the equity and somewhat slowed down the rate of equity erosion.

The high levels of distribution losses and low collection efficiency combined with the problem of KAP makes it difficult to impose and enforce cost effective tariff. Since 2012 ERA is using industry standard benchmarks. Compared to an actual loss level of about 19 percent ERA allows only 9 percent of losses for computing revenue requirements. Similarly it also uses a high benchmark (96%) for collections. These should provide motivation to EPCG to make special efforts to reduce losses and improve collections. A more permanent and sustainable resolution of the complex problem of KAP is also the key to the financial recovery of the sector.

Table A3.2: Key Indicators of Financial Performance of EPCG

Income Statement Items (Euro Million) EPCG						
Item	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Total Revenue	279.77	299.94	306.16	301.15	265.49	282.18
Total operational costs	287.55	317.49	304.34	295.56	349.68	298.14
Operational Income / Loss	(6.68)	(17.19)	4.64	7.35	(82.52)	(14.91)
Net Nonoperational income	(1.20)	(0.08)	(0.04)	8.44	12.13	12.09
Income / Loss Before Tax	(7.88)	(17.27)	4.60	15.79	(70.39)	(2.82)
Income Tax	0.00	0.33	0.44	0.71	3.85	2.96
Income/loss after tax	(7.88)	(17.60)	4.16	15.08	(74.24)	(5.78)
Balance Sheet Items (Euro million) EPCG						
Total Fixed and other Non-current assets	964.56	954.95	840.55	870.97	862.51	862.82
Total Current assets	84.77	112.61	201.11	216.52	186.43	223.44
Of which receivables	57.93	87.34	88.19	96.99	87.74	125.03
Total Assets	1049.33	1067.56	1041.66	1087.49	1048.94	1086.26
Equity shares	991.88	991.88	967.28	967.28	967.28	967.28
Reserves	0.00	0.00	0.00	186.74	186.90	186.83
Retained earnings/ Losses	(58.36)	(79.58)	(72.62)	(228.46)	(295.00)	(300.77)
Total equity	933.52	912.30	894.66	925.56	859.18	853.34
Long Term Borrowings	20.31	29.49	31.13	40.66	47.66	63.63
Deferred income tax liabilities	34.36	20.36	18.18	29.80	33.95	36.01
Long term Provision	0.74	5.57	17.32	24.63	16.91	18.42
Deferred income	3.90	5.52	6.25	7.84	8.58	9.06
Total non-current liabilities	59.31	60.94	72.88	102.93	107.10	127.12
Total current liabilities	56.51	94.76	74.12	59.02	82.64	105.79
Total of liabilities	115.82	155.70	147.00	161.95	189.74	232.91
Total of equity and liabilities	1049.34	1068.00	1041.66	1087.51	1048.92	1086.25
General Memo Items						
Generation Hydro GWh	1278.30	1501.50	2062.60	2749.60	1203.80	1469.90
Generation Thermal GWh	766.40	1155.40	616.90	1271.70	1452.30	1245.10
Generation total GWh	2044.70	2656.90	2679.50	4021.30	2656.10	2715.00
Hydro share in total generation (%)	62.52	56.51	76.98	68.38	45.32	54.14

Imports GWh	3361.00	2806.00	2361.00	1946.00	3499.00	3501.00
Exports GWh	759.00	909.00	1283.00	1946.00	1938.00	2374.00
Sales to Direct customers GWh	2155.70	1955.10	1106.50	1341.10	1478.80	1172.70
Sales to Distribution customers GWh	1802.70	1904.80	1931.60	2013.30	2086.50	2072.80
Total billed sales GWh	3958.40	3859.90	3038.10	3354.40	3565.30	3245.50
Average Tariff for all consumers Euro Cent/kWh	6.9100	7.2200	7.9382	6.2950	5.9770	6.6430

Note: Data in parentheses are negative.

Source: Audited financial statements and EPCG data

Under the Financing Agreement Schedule 2, Section V there is a financial covenant which obliges EPCG to reach in respect of tariff consumers a collection ratio of 94 percent for the year 2009 and maintain that level (or improve over it) in the subsequent years. There is also a second covenant obliging EPCG to achieve a self-financing ratio (SFR) of not less than 35% in 2008 and in the later years.

Based on the information provided by EPCG, the collection ratio covenant target had been missed during 2008-2012 by a small margin and has been exceeded in 2013. The success in 2013 is attributable to: (a) greater efforts by the management; (b) KAP not being allowed to receive power as a tariff consumer; (c) benchmarks by the ERA for allowed revenues (see Table A3.3).

Table A3.3: Compliance with Collection Ratio Covenant by EPCG

Year	Actual collections (Euro million)	Amounts billed (Euro million)	Collection Ratio Achieved (%)	Target under the Covenant (%)
2007	253.37	274.93	92.16	>90
2008	255.76	280.88	91.06	>92
2009	246.45	281.65	87.50	>94
2010	234.59	252.32	92.97	>94
2011	223.11	255.54	87.31	>94
2012	227.60	248.30	91.45	>94
2013	182.12	189.77	95.97	>94

The relatively small size of its capital expenditure (1.5 to 5.5 percent) in relation to the size of its operating fixed assets base should normally make it easier to achieve the targeted SFR. Despite making operational losses in four out of six years EPCG had managed to report SFRs well in excess of the target of 35 percent in five of the years (Table A3.4).

TableA3.4: Self Financial Ratios Reported by EPCG

Year	Reported SFR (%)
2007	67
2008	74
2009	105
2010	107
2011	113
2012	19

The apparently high SFRs mask the fact that the cash generated by its power operations alone are not sufficient to achieve any decent level of SFR, as the high SFRs seems to result from financial transactions external to the core power operations. As the size of its capital expenditure increases in future, its internal cash generation from its power operations needs to increase to finance at least 30 to 35 percent of the costs of its expansion program.

Financial performance of CGES (2010-2012)

CGES was legally separated from EPCG in the course of 2009 and the first audited financial statement relates to the year 2010. Its main revenue comes from transmission charges and transit fees and its main expenses are the operation and maintenance costs relating to the transmission system. During the last three years it has been making operational profits. Its profits after tax moved from Euro 5.16 m in 2010 to Euro 3.50m in 2011 and to Euro 6.57m in 2012.

Somewhat like EPCG the assets of CGES are also financed mostly by contributed equity and its long term debt is small. Its equity base is increasing mostly on account of the retained earnings. In 2012 it had trade receivables amounting to Euro 5.36m or the equivalent of about 2.25 months' sales. Much of it is from EPCG and the supplier of KAP. By taking supplies from the grid and not paying for it, KAP caused damage to the sector in the regional market and particularly to CGES in the past and the government had to take some special steps to resolve this issue. It remains to be seen whether the KAP situation will not affect the financial viability of EPCG and CGES in the future.

Table A3.4: Key Indicators of Financial Performance of CGES

Income Statement Items (Euro million) CGES

Item	**2010**	**2011**	**2012**
Total Revenue	27.60	26.03	29.16
Total operational costs	21.43	22.26	23.52
Operational Income / Loss	6.17	3.77	5.64
Nonoperational income net	(0.50)	0.17	1.60
Income / Loss Before Tax	5.67	3.94	7.24
Income Tax	0.51	0.44	0.67
Income/loss after tax	5.16	3.50	6.57
Balance Sheet Items (Euro million) CGES			
Total Fixed and Non-current assets	133.20	136.79	143.95
Current assets	18.74	57.11	54.84
Of which Trade and other receivables	5.15	6.91	6.21
Total Assets	151.94	193.90	198.79
Equity shares	120.85	155.11	155.11
Reserves	0.00	0.00	0.25
Retained earnings/ Losses	3.32	6.83	9.87
Total equity	124.17	161.94	165.23
Long Term Borrowings	17.83	20.81	19.95
Total non-current liabilities	18.93	22.24	22.23

Total current liabilities	8.85	9.72	11.33
Total of liabilities	27.78	31.96	33.56
Total of equity and liabilities	151.94	193.90	198.79

Note: Data in parentheses are negative.
Source: Audited financial statements of CGES

The collection ratio covenant is not applicable to CGES since it does not deal with tariff consumers. However the SFR covenant is applicable to it. According to the data and calculations provided by it based on audited accounts it has substantially exceeded the target of 35 percent in each of the three years (Table A3.5)

Table A3.5: Compliance with SFR Ratio covenant by CGES

Year	Target SFR (%)	Achieved SFR (%)
2010	35	217
2011	35	73
2012	35	74

The high levels of SFR are probably due to the relatively small capital investment program pursued during the period.

Annex 4. Bank Lending and Implementation Support/Supervision Processes

(a) Task Team members

Names	Title	Unit	Responsibility / Specialty
Lending			
Supervision/ICR			
Bernard Baratz	Consultant	EASCS	
Aleksandar Crnomarkovic	Sr Financial Management Specialist	ECSO3	
Miroslav Frick	Operations Officer	ECSEG	
Franz Gerner	Lead Energy Specialist	EASVS	
Sergio Augusto Gonzalez Coltrinari	Senior Energy Specialist	LCSEG	
Lewis Raymond Hawke	Lead Public Sector Specialist	ECSP4	
Nikola Ille	Senior Environmental Specialist	ECSEN	
Surekha Jaddoo	Consultant	ECSEG	
Plamen Stoyanov Kirov	Senior Procurement Specialist	LCSPT	
Sanela Ljuca	Operations Officer	ECCBM	
Paula F. Lytle	Senior Social Development Specialist	AFTCS	
Chukwudi H. Okafor	Senior Social Development Specialist	AFTCS	
Nenad Pavlovic	Consultant	ECSEG	
Norval Stanley Peabody	Consultant	LCSEG	
Anna L Wielogorska	Senior Procurement Specialist	EASR1	
Richard Wong	Consultant	ECSSD	
Jose M. Martinez	Senior Procurement Specialist	ECCU4	

(b) Staff Time and Cost

Stage of Project Cycle	Staff Time and Cost (Bank Budget Only)	
	No. of staff weeks	USD Thousands (including travel and consultant costs)
Lending		
FY07		39.84
FY08		-0.06
Total:		39.78
Supervision/ICR		
FY07		0.00
FY08		84.96
Total:		84.96

Annex 5. Beneficiary Survey Results

(if any)

None

Annex 6. Stakeholder Workshop Report and Results

(if any)

None

Annex 7. Summary of Borrower's ICR and/or Comments on Draft ICR

The Borrower’s ICR of January 2014 is 31 pages long and contains a detailed description of the project, its implementation, its costs, and benefits as well as explanations for variations between what were envisaged at the time of appraisal and what actually happened. It focuses on the physical components of the project and does not deal with the sector reform or the regional market related initiatives pursued under the *EC Treaty*.

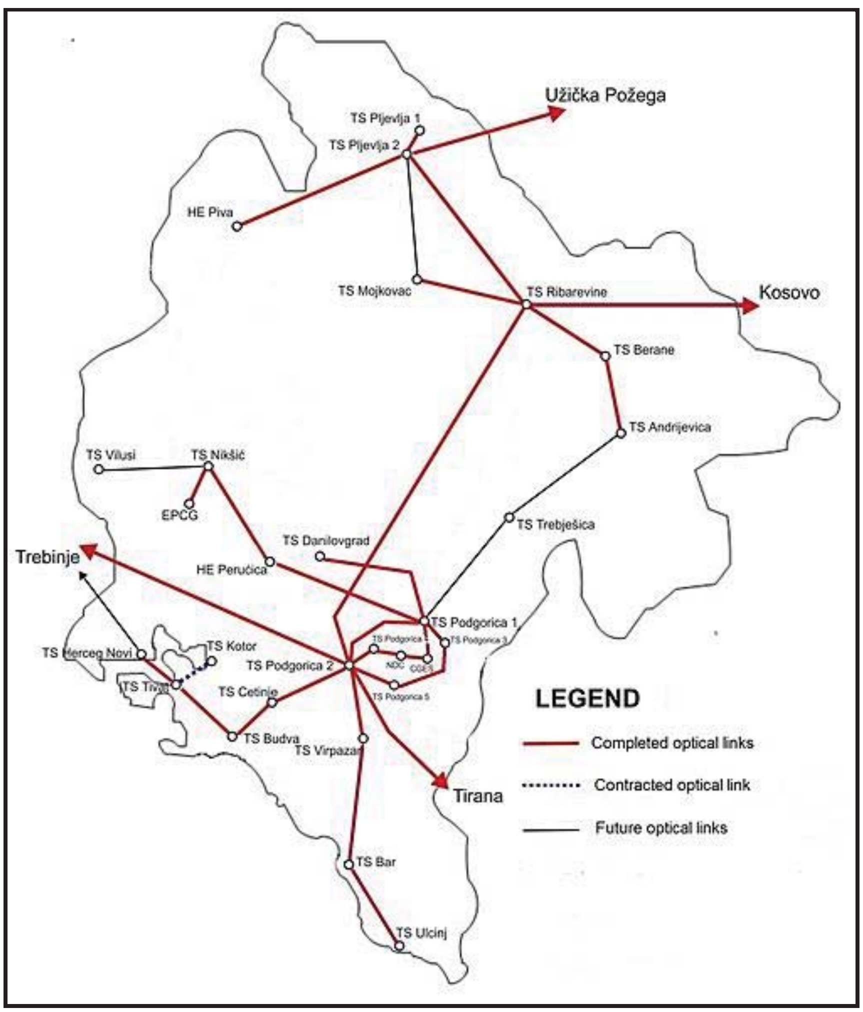
It outlines the components in detail and compares project cost as appraised and as envisaged now at the time of project completion. The project is being completed within the budget at a cost of Euro 13.13 million (actual expenses as of mid-January 2014 plus expected payments for works completed already) compared to the appraisal cost estimate of Euro 13.33 million. The actual share of the borrower in financing was about 50 percent of the total actual cost compared to the appraisal estimate of about 43 percent.

For the *First (Telecommunication) Component*, EPCG hired in the middle of the year 2007 a Consulting firm (KORONA DD of Slovenia) whose selection and terms of reference were first agreed with the Bank. The consulting services contract was financed from the funds of EPCG. In accordance with the designs, specifications and the implementation plan for Component 1 developed by the hired Consultant and declared acceptable by the Bank, further implementation proceeded. In the first stage OPGW was installed on 368 km of overhead lines (15 sections), and telecommunication equipment were installed in 21 nodes. These included telecommunication links to Serbia and Bosnia Herzegovina. Using the substantial savings from the first stage and based on the Restructuring of the Credit stage 2 was implemented under which OPGW was installed on 171 km of overhead lines (8 sections), and telecommunication equipment were installed at 5 nodes. The stage 2 also included telecommunication connection up to the border of Kosovo, Facility for remote monitoring of optical cables in real time, and technological upgrades of the previously installed 21 nodes. The delays in the implementation of this component were caused by the difficulties faced in procuring OPGW of accurate lengths and of the right quality and unfavorable whether condition which damaged the installed OPGW in certain sections and the need to reinstall them during the next available season. Completion of the construction of telecommunication system allowed CGES to have a reliable network providing connection of the following systems:

- SCADA (system for monitoring and control): Termination stations, which communicate with the server in NDC through telecommunication system, were installed in 23 facilities;
- EMS (state estimator, power flow calculation, security analyses) uses data obtained from SCADA system and data exchanged with neighboring TSOs (Transmission System Operator) by means of EH (Electronic Highway) through TASE2 protocol;
- CGES is connected to EH. EH node is formed with 10Mb links towards EMS and NOS B&H;
- CGES is connected with OST link 10Mb;

- Observability Monitor (monitoring of neighboring systems) uses data obtained from SCADA system and data exchanged with neighboring TSOs by means of EH through TASE2 protocol;
- WAMS (Wide Area Measurement System), i.e. monitoring of dynamic events in the system; measuring current and voltage and their phase at a resolution of 20ms; it uses data obtained from 5 PMU installed in the facilities of CGES and data obtained from other TSOs through EH;
- AMR (Automatic Meter Reading); about 100 meters installed in the facilities of CGES communicate with the server in NDC through telecommunication system;
- Scalar (system for detection of lightning strokes) communicates with the server in Slovenia through EH;
- 23 facilities are connected to the optical system and all communication (voice and control informatics, measuring) is conducted through telecommunication system;
- In the initial phase of the implementation of the video surveillance system in all facilities, cameras have been installed in 2 facilities.

The Map below indicates the telecommunication system constructed under the project.



The purpose of the *Second* (*Transmission) component* is to improve and ensure better power supply security of the central and northeastern part of Montenegro, i.e. areas of Mojkovac, Kolašin, Bijelo Polje, Berane and Andrijevica.

Construction Works in Andrijevica commenced on 15 June 2010. They were completed and the transformer station and connecting overhead lines were energized on August 24, 2011. Use permit was also obtained. Construction works in Mojkovas commenced on July 15, 2012 and completed on August 1, 2013, when the facilities were energized and put into operation. Use permit is being obtained. In the implementation of this component both World Bank procedures and those required under the laws of Montenegro had to be observed in respect of land expropriation and environmental protection. The main reasons for delays were: (a) delays in the preparation of designs, (b) legal procedures for land expropriation and compensation, (c) the time consuming need to secure permits and approvals on urban and technical conditions, consents and local taxes from various authorities (ministries and municipal agencies), and (d) to some extent the legal unbundling of CGES from EPCG.

The best project performance indicators are smaller number and reduced time of outages and significantly reduced undelivered electric energy. It is noteworthy that there were no outages at both substations since March 31, 2013.

The objective of the *third (HPP) component* is to improve the reliability of Perucica HPP by replacing its trash rack and providing a new trash rack cleaning equipment as well as providing a spare turbine runner. The trash rack related works were completed in September 2009. It has reduced annual expenses relating to trash rack to the extent of Euro 105,000 and has greatly improved the reliability of the Perucica HPP. In 2010, the year with huge water flows, the new trash rack system operated without stoppage and enabled the plant to achieve a reliability index of 99.79 percent and an availability index of 89.84 percent. In addition the replacement of old trash rack and cleaning system by the new one significantly reduces water losses in the water retention area of this HPP (VRTAC).

The turbine runner was procured and installed in Unit A7 in September 2011under the IDA credit. EPCG had also procured partly under its own financing and partly under EIB financing six other runners which have been installed Units 3A and 3B, 4A and 4B, 6A and 7B during 2004-2011. They have also contributed to the improved availability of the seven generating units in this HPP. The report provides availability statistics for each unit.

After listing a variety of project benefits the report takes a *special note* of: (a) Good cooperation with members of the World Bank's team; (b) Accuracy and coherence of the required reports (social and environmental), with a special emphasis on the good cooperation with the environmental specialist, and (c) Continuous controls – regular WB missions for the purpose of joint working on the efficiency of project implementation/completion". It further observes, "Cooperation with the Bank's representatives is assessed to have been very good during the preparation and implementation of the project, which produced more efficient writing of the reports with fewer remarks. Feedbacks and discussions from the Bank's officers on the quality of the reports, identification and control as well as their contribution to the entire project implementation are highly satisfactory". Under the CGES components it observes "Here we would like to emphasize a very good cooperation with members of the World Bank's team in efficient, precise and clear preparing and submitting of required reports, especially a good cooperation with the environmental specialist having in mind the specificity of these issues that were relatively new to us. Regular visits paid by the World Bank's specialists influenced the efficiency, organization and coherence of the project implementation, so that their contribution to the overall project implementation is very satisfactory".

It identifies the *lessons learnt* as follows: "We regard the Bank's approach regarding organization of public discussions about EMP[17] and LAPF[18] prior to the commencement of project implementation by the investor, to which various potential stakeholders, non-governmental organizations, organizations dealing with ecology, social and political associations, etc. are invited, as a very useful experience and good practice which CGES should apply to all its investment projects. Suffice it to say that as a result of this CGES obtained information on the presence of hazardous waste on the area envisaged for the extension of TS Mojkovac, which resulted in taking necessary activities on the environmental protection.

Working on this project allowed a certain number of employees from CGES and EPCG as well as outside the PMU to get acquainted with the Bank's rules and procedures for procurement of goods and works by involving them in the Commissions for tender preparation and bid evaluation, which will surely be useful in the implementation of future similar investment projects.

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[17] Environment Management Plan
[18] Land Acquisition Policy Framework

Annex 8. Comments of Cofinanciers and Other Partners/Stakeholders

None

Annex 9. List of Supporting Documents

Quarterly Progress reports from the PIU
Audited Annual Financial Statements of EPCG (2008-2012) and CGES (2010-2012
Audited project expenses statements
Borrower's ICR (2014)
Aide memoires of the project supervision missions (2007-2013)
ISRs of the project
Draft Report of QAG (2010)
Annual Implementation Reports of the EC secretariat 2012 and 2013
Energy Law (2010)

Annex 10: Availability of, and annual generation from, the units of Perucica HPP

Based on the data provided by EPCG the following tables on the availability of the generating units of the Perucica HPP and annual generation from them had been compiled. It may be seen that there is a notable improvement of the availability after the replacement of the runners of units 3, 4 and 7. The Bank financed runner was used to replace of the two runners of Unit 7. The other runner for unit 7 was financed by EPCG. The correlation between runner replacement and annual generation is not easily discernable.

Annual Availability of the Generating Units of Perucica HPP (%)

Unit YEAR	1 %	2 %	3 %	4 %	5 %	6 %	7 %
2006.	17.2	42.5	91.9	82.0	91.5	91.7	90.9
2007.	93.3	93.3	51.7	77.1	88.4	95.1	83.1
2008.	89.1	84.1	**73.9**	45.9	76.6	80.4	81.7
2009.	81.2	78.8	79.2	79.6	79.8	75.1	74.5
2010.	90.9	90.7	89.8	88.7	88.9	90.8	89.2
2011.	92.1	78.5	91.4	**83.5**	89.8	87.3	**87.0**
2012.	93.4	93.4	86.5	93.2	88.1	90.9	92.8
2013.	89.9	89.6	90.0	89.6	89.3	88.1	90.2

Source: Based on data provided by EPCG

Note: Availability includes actual hours of operation in a year of 8760 hours plus the number of hours during which the units were in the standby mode ready to start operating at a moment's notice and it is expressed as a %. Each unit needs two runners. Numbers in "bold" indicate the year in which the runners were replaced in the Unit.

Annual Electricity Generation from each Generating Unit at Perucica HPP (GWh)

Unit No.	Installed capacity (MW)	Generation in GWh						
		2006	2007	2008	2009	2010	2011	2012
1	38	20.00	142.32	158.93	158.93	191.97	93.62	113.99
2	38	77.48	112.30	155.42	155.42	209.13	99.84	141.34
3	38	116.82	51.23	**93.93**	165.56	199.98	111.49	138.17
4	38	108.70	64.56	70.58	168.34	201.05	**120.00**	138.08
5	30	129.51	56.52	76.29	107.60	144.93	53.81	75.19
6	58.5	198.61	173.84	169.24	172.39	248.51	85.28	99.21
7	58.5	185.70	137.81	158.21	171.38	239.34	**65.71**	102.56

Source: Based on data provided by EPCG

Note: Numbers in "bold" indicate the year in which the runners were replaced in the Unit. IDA financed runner was one of the two runners replaced in Unit 7. One of the two runners in Unit 6 was replaced in 2004.

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