Content

Glossary and abbreviations

Glossary

Additionality	A requirement that the emission reductions associated with a Project exceed those that would have occurred in the absence of the Project.
Alternative Scenario	A description of a plausible alternative to the Project.
Baseline	The scenario that reasonably represents the anthropogenic emissions by sources of greenhouse gases that would occur in the absence of the JI Project
Baseline Emissions	A quantification of the anthropogenic emissions of greenhouse gases in the Baseline Scenario
Baseline Methodology	The approach taken to identifying the Baseline Scenario and quantifying the emissions in this scenario
Baseline Scenario	A narrative description of what would have occurred in the absence of the JI Project
Build Margin	The emissions factor representing the emissions associated with the marginal generation of electricity for newly built technology on an integrated network
Clean Development Mechanism	The mechanism established under the Kyoto Protocol that enables projects hosted in non-Annex I countries to generate certified emission reduction units that can be traded and used by companies or countries in Annex I to meet domestic and/or international emissions reduction commitments.
Combined heat and power	Energy production technology that produces both heat and power as useful products
Combined Margin	The weighted average of the Operating Margin and Build Margin
Emission Reductions	The differences between anthropogenic emissions of greenhouse gases in the Baseline and the Project
Emissions Factor	The anthropogenic emissions of greenhouse gases per unit of output (e.g. per kWh of electricity)
Greenhouse gases	The gases Carbon dioxide, Methane, Nitrous oxide, Hydrofluorocarbons, Perfluorocarbons, Sulphur hexafluoride, as listed in Annex A to the Kyoto Protocol
Joint Implementation	The mechanism established under the Kyoto Protocol that provides Annex I countries or their companies the ability to jointly implement greenhouse gas emissions reduction or sequestration projects that generate tradable Emissions Reduction Units
Kyoto Protocol	The Kyoto Protocol to the UNFCCC is an international agreement reached at the Third Conference of Parties to the UNFCCC in December 1997. The agreement committed 38 industrialised countries to reduce or limit emission reductions. Parties to the Protocol have legally binding emission reduction or limitation targets that must be met during the period 2008–2012. The Protocol enters into force, 16 February 2005
Leakage	The net change of greenhouse gas emissions which occurs outside the project boundary and that is measurable and attributable to the project activity
Operating Margin	The emissions factor representing the emissions associated with the marginal generation of electricity given existing technology on an integrated network
Project Boundary	The notional boundaries set around the Project within which the effects of the project on greenhouse gas emissions should be considered and quantified

Project Emissions	A quantification of the anthropogenic emissions of greenhouse gases in the Project
United Nations Framework Convention on Climate Change (UNFCCC)	Adopted in May 1992 and signed at the 1992 Earth Summit in Rio de Janeiro by more than 150 countries and the European Community and entered into force in March 1994. Its ultimate objective is the 'stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system.

Abbreviations

BAU	Business as Usual
CCGT	Combined Cycle Gas Turbine
CDM	Clean Development Mechanism
CH_4	Methane
CHP	Combined Heat and Power
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
ERU	Emission Reduction Unit
FOREM	Federal Wholesale Electric Energy (Power) Market
g.c.e.	Grams coal equivalent
GHG	Greenhouse Gas
IPCC	Intergovernmental Panel on Climate Change
JI	Joint Implementation
kWh	Kilowatt hour
MWh	Megawatt hour
N_2O	Nitrous Oxide
ODA	Overseas Development Assistance
PV	Present Value
RAO UES	Unified Electricity System of Russia
t.c.e.	Tons coal equivalent

Preface

This report was prepared primarily by ECON Analysis. However, valuable contributions have been made by staff of the Arkhangelsk Oblast Energy Efficiency Centre, in particular Ms Naida Murtazalieva who has drafted Annex C and assisted with the case studies. In addition, Ms Anastasia Moskalenko of the National Carbon Union of Russia assisted with the development of Annex A and the implementation of the combined margin methodology.

An earlier draft of the report was reviewed by Kenneth Möllersten of the Swedish Energy Agency (Energimyndigheten) and we thank him for his detailed comments.

We would also like to acknowledge the contributions of the steering committee established for this assignment, including Mr Alexander Somorodov of the Environmental Investment Centre in Arkhangelsk.

The Climate Change Policy Working Group does not necessarily share the views and conclusions of the report, but looks at it as a contribution to our knowledge about Joint Implementation in the Baltic Sea Region.

Oslo, June 2006

Jon Dahl Engebretsen
Chairman of the Climate Change Working Group

Summary

Background

ECON has been appointed by the Nordic Council of Ministers to undertake the project "Development of sector-specific baselines for energy-related JI projects in the Baltic Sea Region". The project has developed baseline methodologies that can be used in the power and district heating sectors of the Baltic Sea Region, and has applied these methodologies to case studies in the Arkhangelsk region of Russia.

Joint Implementation (JI) is the mechanism established under the Kyoto Protocol that provides Annex I countries or their companies the ability to jointly implement greenhouse gas emissions reduction or sequestration projects that generate tradable Emissions Reduction Units (ERUs). There are two "tracks" for implementing this trade:

- *First track JI:* Essentially an emissions trading scheme based on projects that reduce or sequester emissions applicable where a country fulfils all of the eligibility requirements for emissions trading under the Kyoto Protocol. First Track JI does not involve international governance such as under the CDM, and host countries have greater discretion on all project aspects including determination of additionality of projects.
- *Second Track JI:* The alternative to First Track; it is required for countries who meet only a certain number of the eligibility requirements. Under this track, some oversight is provided by an international governance system somewhat similar to that under the CDM.

The rules determining the eligibility under JI are set out in Article 6 of the Protocol and the Marrakech Accords. To participate under First Track JI, countries must meet all of the following requirements:

- The country must be a Party to the Kyoto Protocol;
- It must have calculated and recorded its Assigned Amounts;
- There must be a national registry in place;
- There must be a national system for estimating GHG emissions;[1]
- The country must have submitted annually the most recent required GHG inventory[2] and supplementary information on its Assigned Amount.

[1] Article 5 paragraph 1 Protocol.

In order to transfer ERUs under Second Track JI, Parties must meet the first three requirements listed above. The requirements and procedures applying to countries/projects under Second Track JI are not clearly set out in the JI rules. They are yet to be designed by the JI Supervisory Committee. They are expected to be very similar to the procedures specified under the CDM. Current JI projects are generally being assessed against the CDM system. In cases where a host country does not meet any of the eligibility requirements, JI projects may still be undertaken, but ERUs cannot be traded.

Under Second Track JI, establishing a baseline against which emission reductions can be determined is an important part of the project cycle.

Baselines and Baseline methodologies

The baseline for a project can be defined as the scenario that reasonably represents the anthropogenic emissions of greenhouse gases that would occur in the absence of the proposed project. It is useful to identify two components to the Baseline:

- *The Baseline Scenario:* Being a narrative description of what would have occurred in the absence of the JI Project;
- *Baseline Emissions:* Being a quantification of the greenhouse gas emissions in the Baseline Scenario.

The Baseline Methodology is then the approach that is used to identify the Baseline Scenario and determine the Baseline Emissions.

There is interest in developing *sector-wide baselines.* All *baseline methodologies* should be fairly general in their approach, applicable to at least a class of projects and perhaps even a sector. However, when a methodology is applied in different contexts, it may well result in different baseline scenarios and baseline emissions. Perhaps the best example of a sector-wide baseline methodology is that for determining the emissions factor of an electricity network. This is due to the physical nature of a power network that makes it possible to determine a baseline for the entire network[3].

Baseline emissions can be expressed as *absolute* (i.e. tons CO_2e/year) or *relative* values (i.e. emissions factors – e.g. tons CO_2e/MWh). The latter are useful in circumstances when the output of the project (and hence the extent of emissions displacement) is unknown. Also, emissions factors can be used for dealing with suppressed demand – where a project expands output to meet demand that may be suppressed in the baseline scenario.

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[2] Article 7 of the Protocol.

[3] Where there are significant transmission constraints in an integrated network, it is advisable to devide the network into segments and so determine the emission factor for each segment.

Baselines can also be *static*, in the sense that they are determined *ex-ante* and remain fixed during the period for determining emission reductions, or *dynamic*, in that they may be updated periodically or on specific triggers. The most common case of this may be the annual update of an emissions factor based on more recent data. Alternatively, a certain event may trigger a complete evaluation of the baseline, possibly resulting in the identification of a new baseline scenario.

Identification of the Baseline Scenario and evidence of additionality

An important part of any baseline methodology is the identification of the baseline scenario – i.e. what would have happened in the absence of the project implemented as a JI (or CDM) project.

Identification of the baseline scenario also allows evidence to be shown that the project is additional, i.e. would not have occurred "anyway". If the project is additional, the process of identifying the baseline scenario should demonstrate that this scenario is different from the project itself.

The Executive Board of the CDM has published a consolidated additionality tool for CDM projects that allows for "a step-wise approach to demonstrate and assess additionality", including identifying alternatives to the potential CDM project. This tool is a fairly stringent one, and it is quite likely that less stringent requirements will be set for JI projects. However, it represents the most developed approach, and in the methodologies presented in this report we have adapted (and simplified) this approach for application to JI projects.

The approach taken is consistent across all methodologies presented here, and is summarised in the figure below. It starts with an identification of the set of plausible alternatives (including the project undertaken *not* as a JI project). It is not necessary to undertake both Steps 2 and 3. If Step 2 is not undertaken, then Step 3 must be, in order to rank the alternatives and identify the Baseline Scenario from among these. If Step 2 is undertaken, and it results in only one of the alternative scenarios not having prohibitive barriers, then this is the Baseline Scenario, and Step 3 need not be undertaken. If Step 2 "passes" two or more scenarios, then Step 3 must be undertaken to rank these remaining scenarios. Step 4 is a "check" on additionality, to ascertain whether the project is common practice under similar circumstances. If so, the project is not additional.

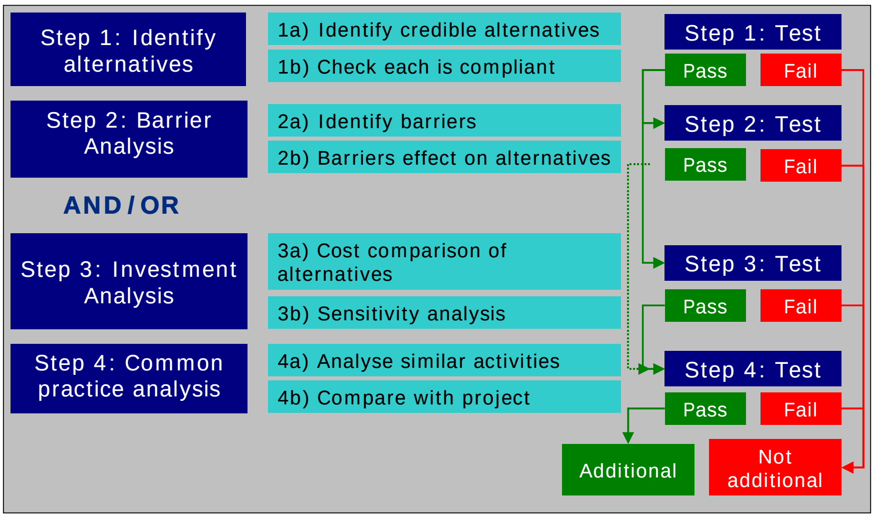

Figure A. Baseline scenario identification and additionality testing

Baseline Methodologies for power and district heating projects

We have developed a set of four Baseline Methodologies, largely based on precedents set under the CDM. In addition, we have adapted the consolidated methodology for grid-connected renewables (the "Combined Margin") for application in countries such as Russia.

These methodologies are designed to cover a wide range of potential JI projects in the power and district heating sectors. In the context of JI in Russia and neighbouring states, it is important to consider combined heat and power (CHP) technologies, as these are important to both power and heat production in these countries. For this reason, we have proposed a methodology specifically for CHP projects, and have also incorporated special features to deal with CHP in the Combined Margin. Figure B illustrates the application of these methodologies to different types of projects.

The Combined Margin has been adapted to deal with CHP plant – which are not adequately catered for in the consolidated methodology for grid-connected renewable electricity project published by the Executive Board. In addition, options under the Combined Margin consolidated methodology have been selected in this report in order to best fit the situation in Russia, and versions of the underlying formulae have been presented that best fit data availability. Lastly, an approach has been put forward for determining the weight to be placed on the emissions factor of new plants (the "Build Margin"), which is important in the context where demand growth is slow and there is considerable surplus generating capacity.

Each methodology follows the same structure:

- Firstly, there is the identification of the Baseline Scenario and additionality test, as illustrated in Figure A;
- Secondly, there is the identification of emission sources in the Baseline, and the quantification of these emissions where appropriate (not all emission sources are quantified);
- Thirdly, there is the identification of leakages (i.e. emissions due to the project but outside the project boundary), and quantification of these where appropriate;
- Fourthly, there is the estimation of project emissions and emission reductions.

Each baseline methodology also identifies data sources, but does not cover the monitoring methodology, which is required as part of a project design document (PDD).

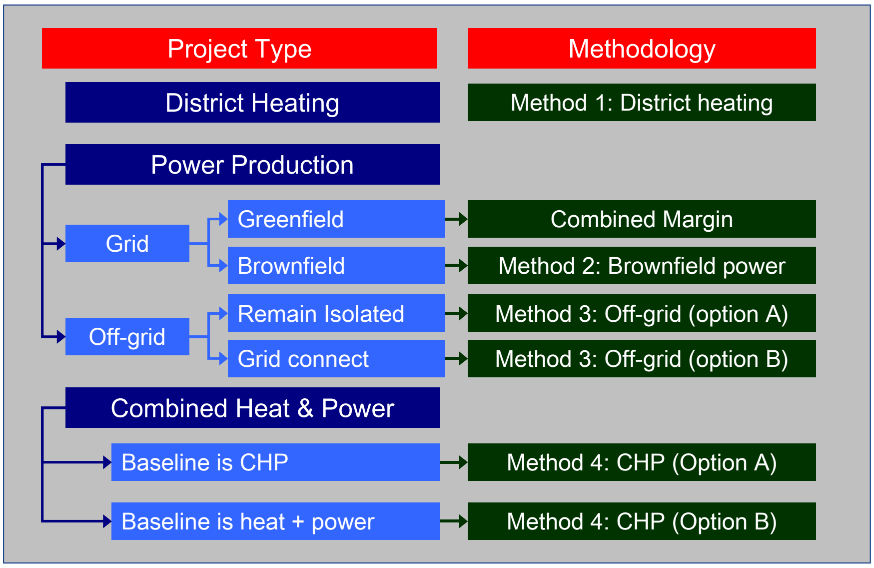

Figure B Baseline Methodologies and their application to projects

Section 2.2 provides an overview of each methodology, and the full methodologies are presented in chapters 7 to 10. The Combined Margin is not presented as a self-standing methodology, but is utilised in several of the other methodologies. For this reason, it is presented as an Annex to this report.

Case studies

A set of four case studies have been developed illustrating the application of these methodologies. The case studies have been drawn from the Arkhangelsk region of North West Russia.

The Arkangelsk Oblast is a useful case study area as it has a fairly self-contained electricity network (so allowing the Combined Margin to be determined for this region). In addition, the Oblast imports significant quantities of power from neighbouring regions (thereby illustrating the application of the method in a wide territory).

Combined Margin

Power supply to the Arkhangelsk network is primarily sourced from a set of three CHP plants operated by the Akhanergo. In addition, there are several industrial self-producers who also export to the network. The Oblast also imports power from the south, and sources this from the FOREM power market.

The Combined Margin is a weighted average of the Operating Margin and the Build Margin. The Operating Margin must take account of imports from FOREM, which is supplied by a mix of nuclear, hydro and thermal capacity. The emissions factor for FOREM was determined to be 0,74 t CO_2e/MWh.

In determining the Operating Margin, it was decided to exclude independent CHP plants as these are primarily driven by their own consumption needs, and so can be considered as “must-run” plants. They also only account for 4 per cent of network supply. This resulting Operating Margin, including imports, was 0,74 t CO_2e/MWh – the same as for FOREM.

There have been no new power plants built in Arkhangelsk in the last ten years, and so the Build Margin was based on new power plants built in Russia over the past five years. The rationale for this is based on the interconnection from Arkhangelsk to the rest of Russia, implying that new build on the Russian network will serve as a proxy for new build in the Arkhangelsk network. This is a mix of gas-fired combined cycle plant, hydropower and two small renewable stations (geothermal and wind). The result was a Build Margin of 0,43 t CO_2e/MWh.

Given the low demand growth in Arkhangelsk over the past five years, a low weighting of 15 per cent was allocated to the Build Margin, giving a Combined Margin of 0,68 t CO_2e/MWh.

District heating case study

Heat is currently supplied to the Severoonezsk town through a district heating system fuelled by a set of oil-fired boilers. It is proposed to construct a biofuel-fired boiler house that will operate year round, and be supplemented by the existing oil-fired boilers in winter. The project will also reduce power consumption at the existing boiler house.

The project is considered additional due to barriers the municipality faces in raising finances for investment projects in general, even though the financial viability of the project is good. While some debt finance is available, the municipality is unable to raise equity for the required investment of €762 000.
The project reduces GHG emissions in the following ways:

- Reduction in combustion of fuel oil at the existing boilers;
- Reduction in methane emissions from avoided disposal of wood wastes;
- Reduction in emissions from power supply to the network, arising from reduced electricity consumption in the heat production system.

The baseline emissions for (i) are determined as the emissions factor for oil combustion in the existing boilers (96 kg CO_2e per GJ of heat produced). The baseline emissions for (ii) are determined from a first order decay method for wood decomposition, resulting in an annual emission of 14 000 t CO_2e in year 1 and rising to 30 000 t CO_2e in year 10, before beginning to decline again. The emissions factor for (iii) is taken as the Combined Margin.

Combined heat and power case study

The Kamenka settlement is currently supplied by heat from a set of coal-fired boilers, and obtains power from a set of diesel generators. Both heat and power supply is currently inadequate for the needs of the settlement.

The project as proposed is to construct a new CHP plant at the nearby Mezen sawmill, fuelled with wood wastes. Although the new plant will also supply the sawmill, it does not have any impact on emissions at the sawmill as it will replace an existing biofuel plant that currently supplies the mill. The new CHP plant will completely replace the diesel generators, and will displace most of the coal used for the Kamenka district heating system (limited use of these boilers will continue – coal use will drop to approximately 20 per cent of former consumption). The project will significantly improve service levels of both heat and power to Kamenka through an increase in heat and power production.

The only plausible alternative to the project is continuation of the current supply solution. The project is considered additional as, for the municipality, the return on investment (IRR) required is low – less than 7 per cent.

Emission reductions from the project arise from

- Reduction in combustion of coal at the existing boilers;
- Reduction in methane emissions from avoided disposal of wood wastes;
- Reduction in emissions from diesel power supply.

The emissions factor for the existing coal boilers was determined as 139 kg CO_2e per GJ of heat produced, and the emissions factor for diesel power supply was identified as 1,02 kg CO_2e/kWh. In addition, the avoided methane emission from land-fill was identified as initially 49 000 t CO_2e per year, rising to 68 000 t CO_2e/yr after 10 years before declining.

Off-grid power supply

OblDES is the organisation in Arkhangelsk that currently supplies electricity to a number of isolated communities. The utility operates some 100 stations in 50 settlements, serving a population of close to 30 000.

OblDES has considered a range of possible investment options, including the interconnection of several localities to the main grid. One such option was the interconnection of seven settlements in the Primorsky district, and connection to the main grid. This project was rejected by OblDES because the investment returns were too low.

The baseline for the project is taken as continued use of the existing diesel generators, and the emissions factor for these is based on the standard emissions factors for diesel power generators. Given the mix of sizes in these settlements, the weighted average baseline emissions factor was determined as 1,23 kg CO2e/kWh.Written in the main language of the report

1. Introduction

1.1 Background

The Kyoto Protocol establishes an international trading system that is composed of an international emissions trading scheme comprised of Annex B countries who are Party to the Protocol and have taken on emissions caps, and two project based trading mechanisms: the Clean Development Mechanism (CDM) and Joint Implementation (JI).

The project-based mechanisms, the CDM and JI, generate credits through emissions reduced or sequestered by specific projects. Although there are many similarities between the two mechanisms, they have separate, independent operations. Credits for JI projects are part of a country's emissions cap, while credits from the CDM are generated from projects that are located outside of Annex B countries (i.e., developing countries) and can therefore be used against the emissions target of an Annex B Party.

The CDM is established under Article 12 of the Protocol and has as its purpose: to assist Parties not included in Annex I (i.e. developing countries) in achieving sustainable development; to contribute to the ultimate objective of the Convention (i.e. stabilize greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system); and to assist Parties included in Annex I (developed countries) in achieving compliance with their quantified emission limitation and reduction commitments under Article 3 of the Kyoto Protocol. The CDM began operation following the conclusion of the seventh session of the Conference of the Parties to the UNFCCC (COP-7). It was at COP-7 that the majority of rules and procedures for the CDM were adopted as well as the rules for JI.

1.1.1 Joint Implementation

Joint Implementation (JI) is the mechanism established under Article 6 of the Kyoto Protocol that provides Annex I countries or their companies the ability to jointly implement greenhouse gas emissions reduction or sequestration projects that generate tradable Emissions Reduction Units. JI has a two-track system in that there are provisions for Parties to trade emission reduction units (or ERUs, the "currency" of the JI) based on two scenarios:

- *First track JI:* Applicable where a country meets all of the eligibility requirements (establishing a national registry and national systems,

calculation of assigned amount, etc.), ERUs can be traded with relative ease, without involvement of international and independent bodies. First track JI is essentially a form of emissions trading based on projects that reduce or sequester emissions. Most countries are not expected to meet the eligibility requirements, however, until at least 2007.
- *Second Track JI:* If countries meet only a certain number of the eligibility requirements, ERUs can be transacted through second track I.. Under this track, some oversight is provided by a supervisory committee and third-party auditing. In addition the JI project cycle has some similarities with the CDM project cycle.
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The rules determining the eligibility under JI are set out in Article 6 of the Protocol and the Marrakech Accords. To participate under First Track JI, countries must meet all of the following requirements:

- The Country must be a Party to the Kyoto Protocol;
- It must have calculated and recorded its Assigned Amounts;
- There must be a national registry in place;
- There must be a national system for estimating GHG emissions;[4]
- The country must have submitted annually the most recent required GHG inventory[5] and supplementary information on its Assigned Amount.

In order to transfer ERUs under Second Track JI, Parties must meet the first three requirements listed above. The requirements and procedures applying to countries/projects under Second Track JI are not clearly set out in the JI rules. They are yet to be designed by the JI Supervisory Committee. They are expected to be very similar to the procedures specified under the CDM. Current JI projects are generally being assessed against the CDM system. In cases where a host country does not meet any of the eligibility requirements, JI projects may still be undertaken, but ERUs cannot be traded.

At the time of writing, there are no countries eligible for trading ERUs under the first track. Russia in particular, has several steps to fulfil before being eligible.

The second track JI project cycle consists of three steps. These are:

- *Step 1: Project Development:* identification and development of a project. A Project Design Document (PDD) must be developed, including development of an emissions baseline, monitoring plans, and compliance with any host country requirements. Other

[4] Article 5 paragraph 1 Protocol.
[5] Article 7 of the Protocol.

requirements include: seeking approval of all Parties involved and determining whether the project is additional.

- *Step 2: Verification Procedure:*
- *(First) Determination*: The PDD and any supporting information is submitted to an independent entity (IE) who must make it publicly available for comment for 30 days. The IE then makes a determination as to whether the project meets the necessary requirements. This “determination” is then made publicly available by the UNFCCC. Forty-five days after the determination is first made public, it is considered final unless either a review is triggered.
- *Project Monitoring*: emissions related to the project are monitored according to the monitoring plan drawn up as part of the PDD. The data collected is submitted to the IE for “determination.” This report is to be made publicly available.
- *(Second) Determination*: The IE “determines” whether the emissions reduced or sequestered were monitored and calculated correctly. The IE submits its results and an explanation to the Supervisory Committee who then makes it publicly available. If no review is requested, this determination is considered final after 15 days.
- *Step 3: Issuance and transfer of ERUs:* Following the second determination, and once the commitment period has begun; host Parties that meet the minimum requirements may issue and transfer ERUs.

The modalities and procedures for JI contained in the Marrakech Accords of November 2001, share some similarities with those of the CDM, but there are several important differences. The most important is that these procedures agreed to a ‘prompt start’ for the CDM, and the CDM rules have been developed extensively over the past three years. The JI text says that the Article 6 Supervisory Committee will only be established at the first COP/MOP, and should develop guidelines for baselines “giving consideration to the relevant work of the Executive Board of the CDM”. In other words, the experience gained under the CDM will guide the Supervisory Committee, but they are not required to adopt the same rules. Given that under JI the host country itself has emission limitations, it is possible that the Supervisory Committee would adopt less complex and stringent additionality and baseline provisions for JI. Nevertheless, we expect that the CDM baseline precedents will form the basis for Second Track JI projects. For this reason, we frequently refer to CDM baseline methodologies in this report.

1.1.2 Application of JI to district heating and power projects

District heating and power systems in the Baltic Sea Region often offer significant opportunity for emission reductions due to the carbonintensive nature of the baseline. Given that such reductions are real, measurable and long term, under the Kyoto Protocol these projects are potentially eligible for JI.

In the power sector, JI projects are likely to be based on fuel-switching or rehabilitation in power plants (often in combined heat and power – CHP – plants used for district heating or industrial applications), typically from coal or fuel oil/mazut to biofuel or natural gas. In addition, there are opportunities for greenfield power project development, utilising renewable sources of fuel such as biomass. There are many locations in Russia where power is supplied through diesel generator sets, and JI projects may involve replacement of these with CHP or other generation technologies.

Two major project types are foreseen for district heating systems (and also those producing heat for process / industrial use), based on a review of current projects:

- Fuel switching – conversion of boilers in boiler houses, usually from coal, mazut / heavy fuel oils to biomass (e.g. wood waste) or natural gas through boiler reconstruction and equipping boilers with a pre-furnace, or in some cases, through replacement of the boiler.
- System rehabilitation – network rehabilitation including renovation and insulation of pipeline systems, upgrading or replacing boiler houses, or upgrading boilers to cogeneration plant.

1.1.3 JI and the CDM experience

The CDM and its governing body, the Executive Board, have been operational since November 2001. In addition, third party auditors have been appointed and accredited and the first projects have been registered. As part of its functions, the CDM Executive Board has overseen the approval of methodologies for baseline and monitoring. The Executive Board has established a body of work that is likely to influence the JI process, once the supervisory committee has been established. The CDM Executive Board has approved a number of baseline methodologies, and has also published a set of “consolidated methodologies” that puts forward more generally applicable methodologies for particular project types. In particular, the Executive Board has published the consolidated baseline methodology for grid-connected electricity generation from renewable sources (ACM0002), which serves as the basis for Annex A: The Combined Margin contained in this report.

Given the greater maturity of the CDM, many actors participating in JI projects are looking to the CDM for precedence in certain areas, particularly for baseline methodologies.

1.1.4 Structure of report

This report is structured into three sections, containing 11 chapters and 2 annexes:

- PART I is an overview of the report.
- The rest of this chapter introduces the core concepts dealt with in the remainder of this report;
- Chapter 2 gives an overview of the methodologies proposed, and links them to project specific types;
- PART II is a presentation of case studies applying the different baseline methodologies.
- Chapter 3 gives an overview of energy supply in Arkhangelsk region and presents the case study of the Combined Margin;
- Chapter 4 presents the case study for the Severoonszk district heating project;
- Chapter 5 presents the case study for the Kamenka combined heat and power project;
- Chapter 6 presents the case study for the interconnection of an off-grid power project to the grid
- PART III presents each methodology, as well as the Combined Margin methodology:
- Chapter 7 presents the methodology for district heating projects;
- Chapter 8 presents the methodology for brownfield power projects;
- Chapter 9 presents the baseline methodology for off-grid power projects;
- Chapter 10 presents the baseline methodology for CHP projects;
- Annex A presents the methodology for determining the Combined Margin, as required in several of the preceding methodologies;
- Annex B presents some useful reference data.

1.2 What is a Baseline?

The rules governing the CDM[6] provide a definition of a Baseline as:

> The baseline for a CDM project activity is the scenario that reasonably represents the anthropogenic emissions by sources of greenhouse gases that would occur in the absence of the proposed project activity. A baseline shall cover emissions from all gases, sectors and source categories listed in Annex A within the project boundary. A baseline shall be deemed to reasonably represent the anthropogenic emissions by sources that would occur in the absence of the proposed project activity

[6] Paragraph 44 of the modalities and procedures for the CDM. Available from http://cdm.unfccc.int/Reference/Documents

Under JI the baseline is defined as "the scenario that reasonably represents the anthropogenic emissions by sources or anthropogenic removals by sinks of greenhouse gases that would occur in the absence of the proposed project. A baseline shall cover emissions from all gases, sectors and source categories listed in Annex A, and anthropogenic removals by sinks, within the project boundary."

In addition, the following criteria are provided: A baseline shall be established:

- On a project-specific basis and/or using a multi-project emissions factor;
- In a transparent manner with regard to the choice of approaches, assumptions, methodologies, parameters, data sources and key factors;
- Taking into account relevant national and/or sectoral policies and circumstances, such as sectoral reform initiatives, local fuel availability, power sector expansion plans, and the economic situation in the project sector;
- In such a way that ERUs cannot be earned for decreases in activity levels outside the project activity or due to *force majeure;* and
- Taking account of uncertainties and using conservative assumptions.

It is useful to identify two components to a Baseline:

- *The Baseline Scenario:* Being a narrative description of what would have occurred in the absence of the JI Project;
- *Baseline Emissions:* Being a quantification of the greenhouse gas emissions in the Baseline Scenario, often expressed as an emissions factor, i.e. emissions per unit of product (e.g. tonne CO_2 per MWh of electricity).

The Project is the activity being proposed as the JI activity, and can also be considered to comprise both a narrative description of the project activity and a quantification of the emissions in this scenario.

Emission reductions are then the difference between the Baseline emissions and the Project emissions. Naturally, if the Project is itself the Baseline, then there are no emission reductions that are considered additional.

1.2.1 Baseline methodologies and Project Baselines

A Baseline Methodology is the approach taken to identify the Baseline Scenario and quantify the emissions in this scenario. Preferably, the methodology should include the approach to determining the "additionality" of the project, i.e. showing that the Project is not the Baseline.

A Baseline Methodology should be applicable to a certain category of Project, that is, it should be generally applicable beyond the context of any one specific project.

When this methodology is applied to a specific case, it generates the Baseline for that case, including both an identification of the Baseline Scenario and a quantification of the Baseline emissions.

1.2.2 Sector-specific v Project specific Baselines

As mentioned above, a Baseline Methodology should be applicable beyond any one specific project, and should apply to a category of projects. It is possible that a Baseline Methodology can be developed to apply to all projects within a sector, or at least a wide range of projects in that sector. This is the approach taken in this report, where a set of Baseline Methodologies have been developed that are general in their application.

Nevertheless, these methodologies, when applied to a specific project, would create a Baseline that is specific to that project and would yield project-specific Baselines.

It is possible to consider sector-wide Baselines, i.e. a quantification of the emissions that can represent the Baseline emissions for any Project in that sector (expressed as an emissions factor). This approach is possible under two circumstances:

- Where the physical characteristics of the sector lead to a standard emissions factor applicable across the sector. This is best illustrated in the case of an integrated electricity network with no major transmission constraints where the physical characteristics of the system imply that the impact on emissions is the same (per unit of electricity) wherever electricity is generated (see section 0).
- Where the emissions intensity of the activity does not vary significantly across the sector. An example of this is the case of diesel power generation in off-grid electricity systems. Here, the emissions factor for electricity generation can be based on standard factors with a reasonable degree of accuracy.

The procedures for the CDM create the possibility for defining sector-wide baselines through the use of a benchmark emissions factor. Paragraph 48 of the Marrakesh Rules provides three general approaches to determining Baselines:

- Existing actual or historical greenhouse gas (GHG) emissions, as applicable;
- Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment;

- Average emissions of similar projects undertaken in the previous 5 years, in similar social, environmental and technological circumstances, and whose performance is in the top 20 per cent of their category.

The third of these approaches essentially allows for the establishment of a benchmark emissions factor that is potentially applicable across the sector. There are two major disadvantages of the benchmarking or control group approach to baselines. First, selecting a group of projects in “similar circumstances” that is truly representative is highly subjective, so the baseline methodology may not be replicable and transparent. Secondly, data collection and monitoring can be difficult and expensive. This is one of the main reasons why very few Baseline methodologies have so far used this method.

1.2.3 Absolute v relative Baselines

For many types of projects, the baselines are determined ex-ante to the project commencement, and remain fixed over a crediting period. The baseline may be expressed as

- An absolute baseline: an absolute amount of GHG emissions, or
- A relative baseline: as a carbon emissions factor.

For example, the relative baseline for a power generation project may be given as tons of carbon dioxide per MWh of generation. The actual project emissions reductions will therefore depend on the actual output of the project, not simply the projected output. Another example would be a land fill gas recovery project, where the precise amount of gas collected and therefore not released into the atmosphere is not known until after the project is implemented. For all projects under the CDM and JI., project documents will still estimate emissions reductions ex-ante, but credits are only issued based on project performance i.e. actual emissions reduced or sequestered as measured according to a monitoring plan.

1.2.4 Static v dynamic Baselines

Some baseline methodologies allow for periodic updating of either the absolute baseline emissions or the baseline emissions factor. Such methodologies can be termed “dynamic baselines”. This updating may be:

- Annually: As an example, a power sector baseline methodology might specify that the generation data of all the power plants on the grid should be collected each year, and this data used to update the emissions factor used for the baseline;

- At specified periods, or based on certain triggers that warrant a re-evaluation of the baseline, such as the 21 year (3 x 7 years) crediting period for CDM projects in which the baseline must be re-examined in seven year intervals.

Dynamic baselines have the advantage that they can be more accurate and specifically accommodate changes in the sector or in regulation in a realistic manner. However, they do require additional monitoring and updating routines to be undertaken, and are usually only acceptable where such routines are simple and where the data requirements are not onerous. Further, they offer less certainty over projected income levels for project owners.

1.3 Defining the Project

1.3.1 Project Boundary

The project boundary includes the notional boundaries set around the project within which the impacts and effects of the project on GHG emissions should be considered and quantified. The project boundary shall encompass all emissions by sources of GHGs which are

- under the control of the project participants, which implies either direct control or influence over;
- that are significant: These can be taken as being significant if they can be calculated with a reasonable level of accuracy to be more than one per cent of the total emissions/ emission reductions of the project ; and
- are reasonably attributable to the project activity, this is closely linked to "control over", and project developers may wish to consider the boundary of the infrastructure or investment made.

In other words, the project boundary encompasses all the emission sources that will be directly impacted by the investment project. Baselines should also be defined in such a way that credits cannot be earned for decreases in activity levels outside the project activity or due to *force majeure*.

1.3.2 Leakage

Emission reductions should be adjusted for leakage. Leakage is defined as the net change of GHG emissions which occurs outside the project boundary and that is *measurable* and *attributable* to the project activity. This can include instances where emissions decrease (positive leakage) or increase (negative leakage) outside the boundary, but to date all of the CDM methodologies have only considered negative leakage. The total emissions impact of a JI or CDM project are the emissions reductions within the project boundary less any negative leakage outside the project boundary.

For a district heating project, the project boundary may include the entire plant system including boilers and / or cogeneration units, the transmission system and distribution up to and including substations. An example of leakage for a district heating project involving switching from coal to gas would be upstream fugitive emissions from gas supply and pipelines. If more gas is produced and transported as a result of the project, then fugitive emissions from gas production and transport would be included in the overall project emissions calculations as leakage. The emissions impact should be considered because this change is directly related to the project.[7]

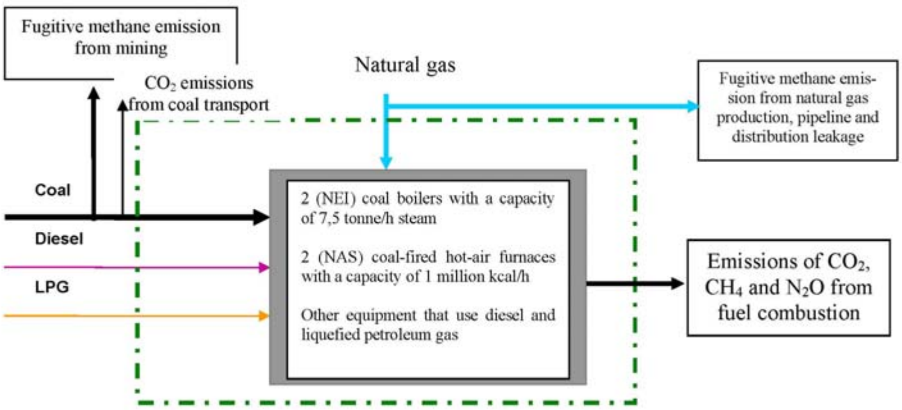

Figure 1. Example of project boundary and leakage from fuel switching project [dotted line is project boundary]

For a power generation project, the project boundary would normally be set as the power plant, including the generation equipment itself and physical connection to the grid. The network itself, including all other power plants connected to it, would be outside the project boundary and emissions from other power plants that are affected by the project would be calculated separately. Because the power sector is a special case, however, avoided emissions from the grid are not treated as leakage but as part of the project emissions, based on an emissions factor calculated for the grid. For other types of electricity projects, e.g. energy efficiency projects, the project boundary again would normally be confined to the equipment installed, and reduction in emissions associated with less gen-

[7] See AM0008 for industrial fuel switching for an example of how upstream emissions are addressed in CDM baseline methodologies.

eration would be calculated separately. In both cases, the impact of network losses should be incorporated in the analysis.

1.3.3 Suppressed demand

It is important to note that the level of service delivered under the Project and Baseline may differ significantly. Quite often, the Project may offer a greater level of service, because in the Baseline Scenario there were constraints on service delivery. The Project thus meets the demand in the Baseline, plus meeting suppressed demand.

A typical example may be the case of an isolated electricity network operated on diesel generation, where the diesel generators are operated for 12 hours per day. If the Project is to interconnect the isolated system, then power will be available for 24 hours per day and more electricity will be consumed. Another example would be increasing the level of comfort in residential buildings with district heating.

Alternatively, one may take the reasonable view that demand for the service will increase over time with population growth and economic growth. Again, expected demand in the Project will be greater than historically experienced.

It is acceptable to determine emission reductions as the difference in actual project emissions and the emissions in the Baseline, *had the Baseline offered the same level of service as the Project* (service equivalence). One approach to implement this is to ensure that the Baseline Scenario is defined as offering the same service as the Project. Alternatively, it is possible to define the Baseline Scenario irrespective of service levels, but to express the Baseline Emissions as an emissions factor. This factor can then be applied to the actual service levels in the Project to determine the Baseline emissions.

This approach with regard to suppressed demand has been accepted by the CDM Methodology Panel in the methodology "NM0046 Andijan district heating". In fact in this case the Panel explicitly rejected the originally proposed approach to use the status quo activity level, and recommended that future activity levels be used to determine both baseline and project emissions (i.e. account for suppressed demand).

1.4 Additionality

A difficult aspect to apply is the concept of additionality and its relation to projects, baseline methodologies and baselines scenarios. A project activity is considered additional if anthropogenic emissions of GHGs by sources are below those which would have occurred in the absence of the registered CDM project activity. It is assumed that the JI rules particularly for "second track" projects will be similar. For projects under the first track, the host country must determine whether emissions are additional.

The "additionality test" is a fundamental part in developing a project's baseline emissions scenario, and the baseline methodology must specify how this will be done. Using an approved baseline methodology does not automatically confer additionality on the projects' emission reductions, however, but rather provides a means for testing additionality. In developing a methodology, the developer must describe how the additionality of the emissions reduced by the candidate project can be determined through the application of the methodology.

1.4.1 How can additionality be tested?

A great deal of emphasis and confusion exists over testing additionality. A project is considered additional if the emissions from the project are lower than those of the baseline. Practically, this means that the project developer must show why the project is not included in the baseline scenario – in other words, why the project is not part of a reasonable description of the likely course of development. In the Project Design Document for a CDM project, this is established with a three stage procedure:[8]

- Description of the baseline scenario determined by applying the baseline methodology (i.e. a description of the technologies and activities that describe the most likely course of development, as opposed to the actual emissions from those technologies and activities).
- Description of the project activity (unless the most plausible scenario is determined to be the project itself.)
- An analysis showing why GHG emissions in the baseline scenario would likely exceed GHG emissions in the project scenario (i.e. quantifying actual carbon impacts of the project vis-à-vis the baseline).

Several tools have been suggested that project developers can use to justify why the project is not part of the baseline. The Executive Board has published a "Tool for the demonstration and assessment of additionality", available from http://cdm.unfccc.int/methodologies/PAmethodologies/approved.html. A more detailed description of this tool is provided below.

Similar tools are used in the Dutch ERUPT to demonstrate additionality:

[8] From CDM Executive Board 2004. Guidelines for completing the Project Design Document (CDM-PDD), the proposed new methodology: baseline (CDM-NMB) and the proposed new methodology: monitoring (CDM-NMM).

- Test 1: The project is not business-as-usual and thus additional because an alternative exists for the project that is more economically attractive.
- Test 2: The project is not business-as-usual and thus additional because without the sale of carbon credits the project is not economically viable.
- Test 3: The project is not business-as-usual and thus additional because several significant barriers exist.

1.4.2 The CDM Consolidated Additionality tool

Given the importance of the CDM as a possible precedent for JI projects, it is useful to examine the consolidated tool for testing additionality as put forward by the CDM Executive Board. Although the Executive Board has made the use of the tool optional except in cases where a methodology requires its use, it is likely to be the main tool that project developers use, at least in the near future.

This tool entails a five step process, as illustrated below in . The process involves establishing a set of plausible scenarios that may apply, narrowing this set down, and showing that the Project is not the most likely scenario or Baseline Scenario from among these scenarios. This selection of the Baseline Scenario is essentially based on one or both of the following tests:

- Is the project less financially attractive than other Scenarios? (Step 2: Investment Analysis)
- Does the Project Scenario face implementation barriers that do not apply to other scenarios? (Step 3: Barrier Analysis).

In addition, the approach has two additional steps which serve to confirm that the Project Scenario is not the Baseline Scenario:

- Firstly, there is an exercise to show that the Project is not common practice under similar circumstances (Step 4: Common practice analysis).

- Secondly, there is an exercise to show that registration of the project as a CDM project activity will alleviate the barriers or investment hurdles identified above (Step 5: Impact of CDM);

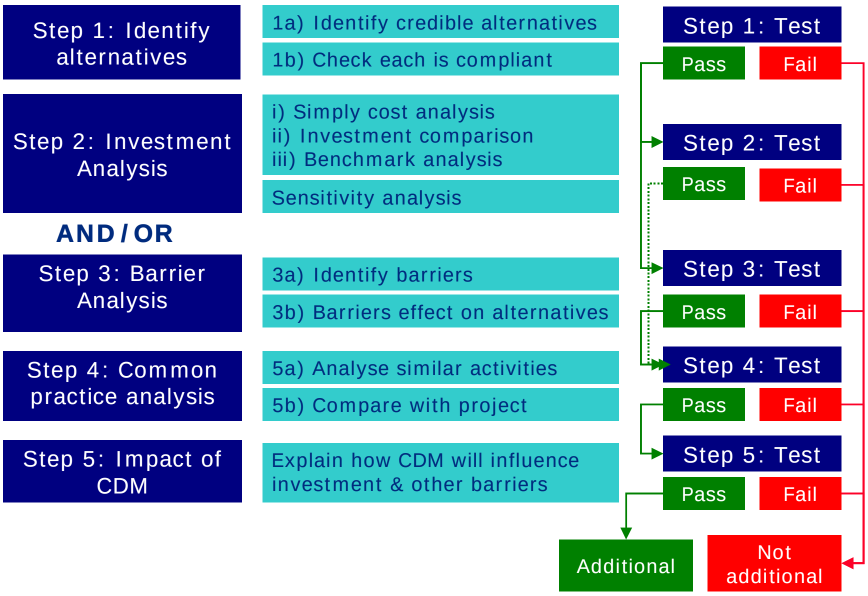

Figure 2 The CDM Consolidated Additionality tool

This tool is a fairly rigorous approach to determination of additionality. In a JI context, it is quite possible that the guideline for additionality will be established more on a national level, rather than establishing an international standard, as for the CDM. It is possible that less strict approaches will be acceptable for JI.

At present, most project developers have adopted the CDM approaches to additionality, and hence the CDM tool represents a good starting point for additionality under second track JI. The approach proposed in the methodologies here is based on the CDM tool as described above, although somewhat simplified, with step 5 (Impact of CDM/JI) being omitted.

1.5 Sector wide Baselines in the power and district heating sectors

1.5.1 Power sector

JI projects that reduce GHG emissions in the power sector are qualitatively different from other types of emission reduction projects. This is because the nature of an electricity network means that the JI activity may influence the operations and emissions of a range of current and future power generation plants.

Since electricity cannot be stored, power supply must equal demand on the network on an instantaneous basis. This implies that if a new generator supplies additional power to the network, it displaces power that would have been generated at other sources. This displacement effect changes the emissions attributable to the power sector, and is the source of emission reductions for many JI power projects.

In certain circumstances, for example a fuel-switching investment at an existing plant, it may be possible to ignore the effects on the remainder of the network. However, in general this will only be the case if the investment does not change the output of the project in any significant way, i.e. the quantity of power generated and the time at which it is generated remain the same. In these circumstances, Baselines need only deal with on-site emissions and need not consider network effects beyond the project's boundaries.

The CDM Executive Board has approved a consolidated methodology applicable to grid connected renewable projects, which can be applied to many grid connected power projects[9]. The methodology, known as the Combined Margin, determines a Baseline Emissions Factor for the entire network based on:

- *The Operating Margin:* A quantification of the Project's impact on emissions given the prevailing set of generating technology;
- *The Build Margin:* A quantification of the Project's impact on emissions from investments in the sector (based on historical investments and not forecast investment).

The Combined Margin is then calculated as a weighted average of these two factors.

This methodology is oriented to renewable electricity projects in developing countries, and does have some limitations when applied to countries such as Russia. In particular:

- The methodology does not deal with CHP plants, where emissions from a CHP plant must be allocated between heat and power outputs;
- The methodology does not give any guidance for situations where there is surplus capacity and demand growth is low. In these circumstances, the weighting given to the Build Margin should be small. The methodology does give some flexibility (but no guidance) in determining this weighting;
- The methodology relies on availability of fuel use at each power station on the network. In many situations (including Russia),

[9] Available as ACM0002 from http://cdm.unfccc.int/methodologies/PAmethodologies/approved.html

specific fuel consumption (i.e. energy utilised per kWh generated) is available rather than absolute quantities of fuel.

Annex A of the report presents a version of the Combined Margin methodology with modifications made to address the limitations and improve its applicability to JI Projects.

The Combined Margin is then utilised in several cases:

- In Methodology 2 (Chapter 8) for projects that involve a change at an existing power station (Brownfield power project);
- In Methodology 3 (Chapter 9) for projects that involve activities in isolated grid systems;
- In Methodology 4 (Chapter 10), the project involves heat and power production in a CHP technology.

1.5.2 District heating sector

Emissions from district heating systems are site specific. There are differences in fuel usage (coal, fuel oil, gas, biofuel) and technologies (boilers, CHP plant). These differences make it difficult to determine a single Baseline emissions factor that is applicable across a range of potential JI projects.

However, it is possible to develop Baseline Methodologies that are generally applicable to district heating projects. This report puts forward two such methodologies:

- Where the project involves only heat production without any associated power production (Methodology 1 in Chapter 3);
- Where the project involves heat and power production in a CHP technology (Methodology 4 in Chapter 10).

2. Baselines and Project types

2.1 Types of Project

The table below summarises the types of Projects that the methodologies outlined in this document are designed to address.

Table 1 Types of Projects

Sector	Type of Project	
District Heating Projects	Heat production: e.g. Fuel switching to gas or biofuels Heat distribution: e.g. Efficiency measures in heat distribution	
Projects in the power sector	Grid projects	Greenfield power projects on a network Fuel switching at existing power stations Energy efficiency in the network or end-use
	Off-grid projects	Remain isolated: Projects that replace diesel generation with a new power source Grid connect: Projects that replace diesel generation with a network connection
Projects that produce both heat and power	Where the alternative is a CHP plant: e.g. Fuel switching at existing CHP stations, expansion of capacity Where the alternative is separate heat and power: e.g. Replacement of separately generated heat and power with CHP	

2.2 Overview of methodologies

A set of four Baseline methodologies are presented here:

- *Methodology 1: District Heating Projects*
- Applicable for Projects that entail the establishment of a new district heating system which does not sell electricity; change of fuel use at an existing district heating system; expansion of the operation at an existing district heating system; or improvement in the efficiency of heat distribution in a district heating system.
- *Methodology 2: Brownfield Power Projects*
- Applicable to Projects that entail retrofits and upgrades to existing, grid connected power stations that do not sell surplus heat.
- *Methodology 3: Off-grid Power Projects*
- Applicable to Projects that entail power generation not connected to the grid, power generation that replaces isolated generation and exports to the main transmission grid, and investments in transmission that connect an isolated electricity supply system to the main transmission grid.

- *Methodology 4: Combined Heat and Power Projects*
- Applicable to Projects that establish a new CHP plant; including change of fuel use at an existing CHP plant; or expanding the operation at an existing CHP plant.

In addition, we have documented an approach to determining the emissions factor on an integrated electricity network (the Combined Margin) based on the Consolidated Methodology for Grid-Connected Renewable Generation. The Consolidated Methodology has been adapted to deal with CHP technologies, and choices have been made to best reflect the conditions applicable in Russia and the Baltic Sea Region. The Combined Margin is used in several of the four methodologies described.

We have not proposed a separate methodology for greenfield power Projects (i.e. new power plants), but such a methodology would simply use the Combined Margin as the Baseline emissions factor.

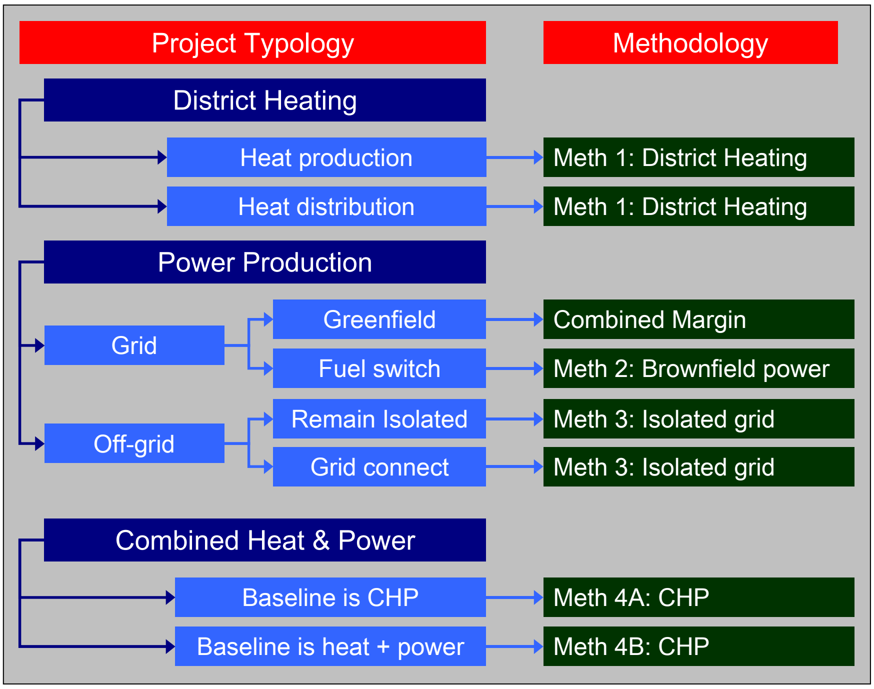

Figure 3 Match between Project types and methodologies

2.2.1 Structure of methodologies

All methodologies have the same structure. There are four parts to this structure, as illustrated below.

- *Part 1: The selection of the Baseline Scenario and test for additionality*. This is the same for all methodologies and is adapted from the consolidated additionality test for the CDM referred to in Section 0 above.

- *Part 2: Determination of Baseline emissions:* Identification of emission sources in the Baseline, and methodology for the quantification of these.
- *Part 3: Identification of leakages:* Identification of any emissions outside the Project Boundary that is measurable and attributable to the Project, and methodology for the quantification of these.
- *Part 4: Estimation of Project emissions and emission reductions:* Identification of GHG emissions in the Project and methodology for quantification of emission reductions in relation to Baseline Emissions.

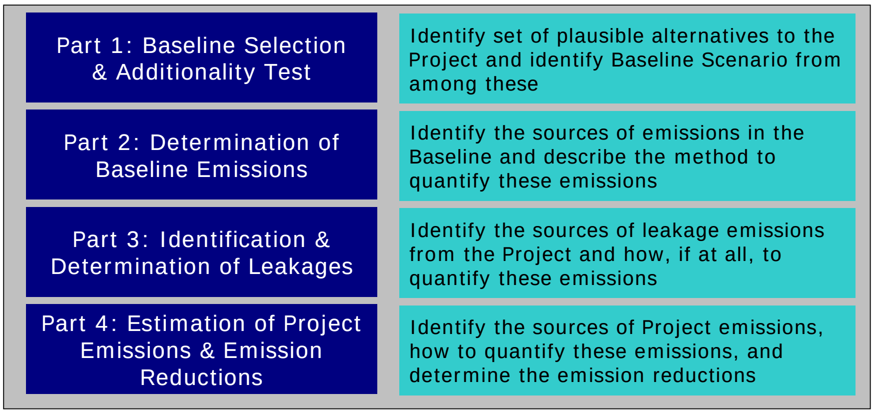

Figure 4 Structure of methodologies

2.2.2 Baseline Scenario identification and additionality test

All methodologies share the same approach to identification of the Baseline Scenario and test for additionality. This is based on the consolidated tool for additionality testing published by the CDM Executive Board. The methodology is illustrated below and consists of the following four steps:

- *Step 1:* A set of plausible scenarios are defined, including the Project itself as a scenario, as well as the business-as-usual case (if appropriate). This set is narrowed down to ensure that all scenarios either comply with regulations or are common practice in the Project area. Following Step 1, proceed to either Step 2 or Step 3.
- *Step 2:* An analysis of barriers to implementation is undertaken and the set of alternative scenarios is narrowed down to eliminate those that face prohibitive barriers. If only one scenario remains, then this is the Baseline Scenario and proceed to step 4, otherwise proceed to step 3.
- *Step 3:* The costs of each remaining scenario are estimated, and a present value of future costs is calculated. The scenario with the lowest cost is the Baseline Scenario.

- *Step 4:* If the Baseline Scenario determined under Steps 3 and/or 4 is the Project itself, then the Project is not additional. Otherwise, assess whether the Project is common practice under conditions similar to those in the Project area. If the Project is common practice, then it is not additional, otherwise the Project is additional.

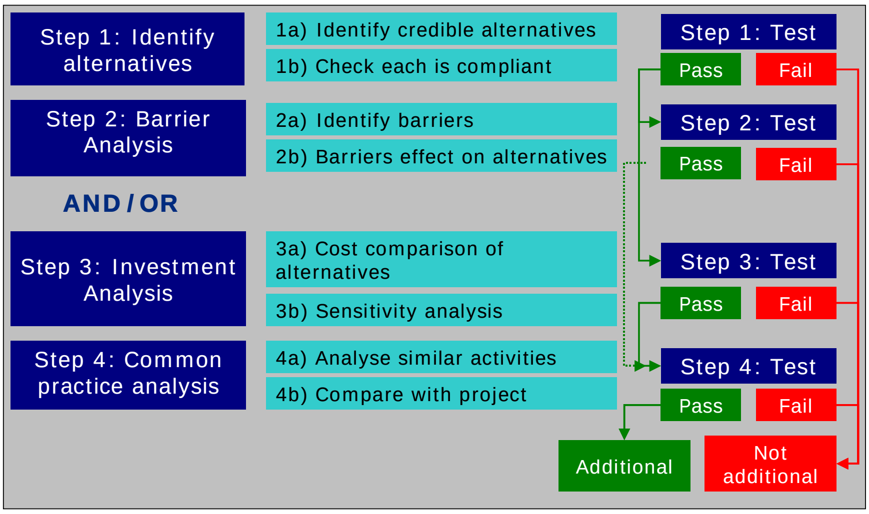

Figure 5 Illustration of Baseline Scenario selection and additionality test

The outcome of these four steps is an identification of the Baseline Scenario from a set of plausible alternatives. If the Baseline Scenario is not the Project, and the Project is not common practice, then the Project is additional.

The Baseline Scenario is then used in the subsequent steps in each methodology for determination of Baseline emissions.

2.2.3 Overview of Methodology 1: District Heating Projects

The figure below illustrates the steps in the methodology for district heating Projects. In addition to the Baseline Scenario identification and additionality test, it involves the following steps:

- *Step 5: Identify emission sources in the Baseline Scenario:* There are two possible sources for emissions in the Baseline – those associated with fossil fuel combustion; and those associated with methane release from the decomposition of wood used in the Project (where the Project uses biomass that would otherwise be stockpiled or land filled).
- *Step 6: Determine Baseline emissions factors:* for fuel combustion emissions, an emissions factor is calculated as the ratio of CO_2, CH_4 and N_2O combustion emissions to heat output. In addition, if methane

emissions from decomposition of wood is part of the Baseline, then these are quantified in absolute terms.

- *Step 7: Identification and determination of leakage:* These are identified but the only source that is quantified is fugitive emissions from natural gas production and transport, in Projects that use natural gas as a fuel, and this is because fugitive gas emissions can be significant contributors to GHG emissions in Russia.
- *Step 8: Identification of sources of Project emissions:* These are identified as emissions from the combustion of fossil fuels, if any, in the Project.
- *Step 9: Estimation of Project emissions factors:* For Projects that entail changes to the method of heat production, the emissions factor for fuel combustion in the Project is determined. For Projects that entail improvements in distribution efficiency, the reduction in losses is determined.
- *Step 10: Estimation of emission reductions:* The emission reductions are then estimated from the emissions factors determine above, and the estimated output of the Project as well as any heat savings.

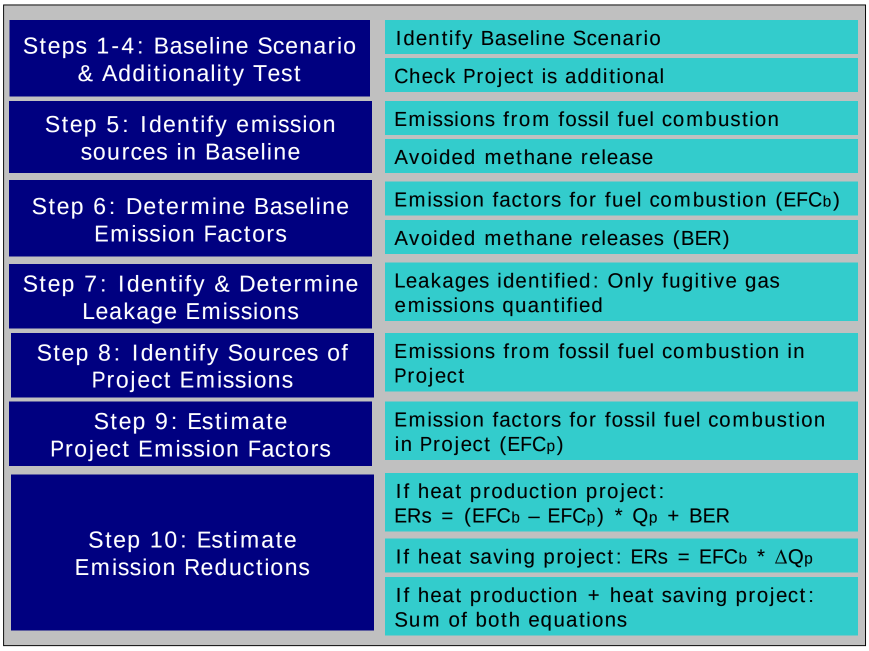

Figure 6 Overview of Methodology 1: District Heating Projects

2.2.4 Overview of Methodology 2: Brownfield Power Projects

This methodology is based on the existing Baseline methodologies for fuel-switching, with the added element of the Combined Margin where power output changes significantly as a result of the Project.

The figure below illustrates the steps in the methodology for brown-field power Projects. In addition to the Baseline Scenario identification and additionality test, it involves the following steps:

- *Step 5: Identify emission sources in the Baseline:* There are three possible sources for emissions in the Baseline:
- those associated with fossil fuel combustion in the Project;
- those associated with fossil fuel combustion from electricity generation on the transmission network (applicable if the output of the Project is higher than in the Baseline, with implications for power supply to the network); and
- those associated with methane release from the decomposition of wood that is stockpiled or landfilled, and is used in the Project.
- *Step 6: Determine Baseline emissions factors:* For emissions from fuel combustion on site, an emissions factor is determined from fuel combustion emissions factors. For electricity generation on the network, the emissions factor is calculated as the Combined Margin as determined in Annex A. In addition, if methane emissions from decomposition of wood are part of the Baseline, then these are quantified in absolute terms.
- *Step 7: Identification and determination of leakage:* These are identified but the only type that is quantified is fugitive emissions from natural gas production and transport, in Projects that use natural gas as a fuel.
- *Step 8: Identification of sources of Project emissions:* These are identified as emissions from the combustion of fossil fuels, if any, in the Project. Where the Project produces less electricity than in the Baseline, then Project emissions will include emissions associated with power supply from the network.
- *Step 9: Estimation of Project emissions factors:* The emissions factor for the Project is calculated based on fossil fuel combustion emissions factors. Where the Project produces less electricity than in the Baseline, then the Combined Margin must be determined as detailed in Annex A.
- *Step 10: Estimation of emission reductions:* There are three cases for determination of emission reductions:
- *Where output from the Project is at a similar level to the Baseline,* emission reductions are calculated as the product of the Project electricity generation and the difference between the Project and Baseline emissions factors, plus emission reductions from any avoided methane release.
- *Where output from the Project is significantly higher than in the Baseline,* emission reductions are calculated in two parts: Firstly, for Project output up to the Baseline level, emission reductions are the product of the Baseline output and the difference in the Baseline and

Project fuel combustion emissions factors. Secondly, for any additional output, the emission reductions are the product of the additional power output and the difference between the Combined Margin and Project fuel combustion emissions factor.

- *Where output from the Project is significantly lower than in the Baseline*, emission reductions are calculated in two parts: Firstly, for the Project output, emission reductions are the product of the Project output and the difference in the Baseline and Project fuel combustion emissions factors. Secondly, for the reduction in output, the emission reductions are the product of a) the difference between the Combined Margin and the Baseline emissions factor; and b) the difference in Baseline and Project output. In other words, if output on site decreases, emissions from the grid will increase, and this emissions increase will offset other emission reductions from the Project.

Steps 1-4: Baseline Scenario & Additionality Test	Identify Baseline Scenario Check project is additional
Step 5: Identify emission sources in Baseline	Emissions from fossil fuel combustion at site If output changes, emissions from network generation If use of stockpiled biomass, avoided methane releases
Step 6: Determine Baseline Emission Factors	Emission factors for fuel combustion (EFC_b) If output changes, Combined Margin (CM) If use of stockpiled biomass, avoided methane (BER)
Step 7: Identify & Determine Leakage Emissions	Leakages identified. Only fugitive gas emissions quantified
Step 8: Identify Sources of Project Emissions	Emissions from fossil fuel combustion in Project
Step 9: Estimate Project Emission Factors	Emission factors for fossil fuel combustion in Project (EFC_p)
Step 10: Estimate Emission Reductions	If Project output same as Baseline: $ERs = (EFC_b – EFC_p) * GEN_p + BER$
	If Project output higher than Baseline: $ERs = (EFC_b – EFC_p) * GEN_b$ $+ (CM – EFC_p) * (GEN_p – GEN_b) + BER$
	If Project output lower than Baseline: $ERs = (EFC_b – EFC_p) * GEN_p$ $+ (EFC_b - CM) * (GEN_b – GEN_p) + BER$

Figure 7 Overview of Methodology 2: Brownfield Power Projects

2.2.5 Overview of Methodology 3: Off-grid Power Projects

There are three different options in this methodology: power generation not connected to the grid, power generation that replaces isolated generation and exports to the grid, and investments in transmission that connect an isolated area to the grid. In addition to the Baseline Scenario identification and additionality test, it involves the following steps:

- *Step 5: Identify emission sources in Baseline:* There are three possible sources for emissions in the Baseline:

- those associated with fossil fuel combustion at the Project site;
- those associated with fossil fuel combustion from electricity generation on the transmission network (applicable if the Project exports to the grid, or brings grid electricity to a previously isolated area); and
- those associated with methane release from the decomposition of wood used in the Project (where the Project uses biomass that would otherwise be stockpiled or land filled).
- *Step 6: Determine Baseline emissions factors:* For emissions from fuel combustion on site, there are three options.
- Where the Baseline Scenario is isolated diesel power generation, the Baseline emissions factor is based on diesel power generation.
- Where the Baseline Scenario is previously isolated diesel power generation, but the Project will export to the grid, then two emissions factors are used. For the amount of electricity consumed locally, the Baseline emissions factor is based on the historical diesel power supply. For electricity output that is exported to the grid, the Baseline emissions factor is the Combined Margin of the grid to which power is exported.
- Where the Baseline Scenario is isolated generation, and the Project is an investment in transmission to bring grid electricity to the area, the Baseline emissions factor is based on diesel power generation.
- In addition, if methane emissions from decomposition of wood are part of the Baseline, then these are quantified in absolute terms.
- *Step 7: Identification and determination of leakage emissions:* These are identified but the only type that is quantified is fugitive emissions from natural gas production and transport, in Projects that use natural gas as a fuel, and this is because fugitive gas emissions can be significant contributors to GHG emissions in Russia.
- *Step 8: Identification of sources of Project emissions:* These are identified as emissions from the combustion of fossil fuels, if any, in the Project. In addition, where grid power is imported, emissions from the grid are Project emissions.
- *Step 9: Estimation of Project emissions factors:* For determination of Project emissions factors, there are two options:
- Where the Project includes measures at a power generation plant, the emissions factor for the Project is calculated based on fossil fuel combustion emissions factors.
- Where the Project includes new transmission lines to connect the area to the grid, the Project emissions factor is based on the Combined Margin of the grid from which the power is purchased.
- *Step 10: Estimation of emission reductions:* There are three cases for estimating emission reductions. In all cases, the avoided methane emissions from avoided biomass stockpiles are also included, where appropriate.

- Where the Baseline Scenario and the Project is isolated power generation, the total emissions reductions are the product of the generation by the Project and the difference in the Baseline and Project emissions factors. Where the Project entails use of biofuel, then avoided methane emissions should be included.
- Where the Baseline Scenario is previously isolated power generation, but the Project will export to the grid, emission reductions arise from the avoidance of diesel power generation for power consumed locally, plus avoided grid emissions. Where the Project entails use of biofuel, then avoided methane emissions should be included.
- Where the Baseline Scenario is previously isolated power generation, but the Project will imported from the grid, emission reductions are the product of power imports and the difference between the Baseline emissions factor and the Combined Margin.

Steps 1-4: Baseline Scenario & Additionality Test	Identify Baseline Scenario Check project is additional
Step 5: Identify emission sources in Baseline	If local generation, then emissions from fossil fuels If grid exports, then grid emissions If use of stockpiled biomass, avoided methane releases
Step 6: Determine Baseline Emission Factors	If local generation, fuel combustion emission factors (EFC_b) If grid exports, Combined Margin (CM) If use of stockpiled biomass, avoided methane (BER)
Step 7: Identify & Determine Leakage Emissions	Leakages identified. Only fugitive gas emissions quantified
Step 8: Identify Sources of Project Emissions	If local generation, emissions from fossil fuel combustion If grid imports, then grid emissions
Step 9: Estimate Project Emission Factors	If local generation, Emission factors for fossil fuel combustion in Project (EFC_p). If grid imports, then Combined Margin (CM)
Step 10: Estimate Emission Reductions	If no grid connection: $ERs = (EFC_b - EFC_p) * GEN_p + BER$
	If Project exports to grid: $ERs = (EFC_b - EFC_p) * (GEN_p - GEN_{ex})$ $+ (CM - EFC_p) * GEN_{ex} + BER$
	If Project imports from grid: $ERs = (EFC_b - CM) * GEN_p + BER$

Figure 8 Overview of Methodology 3: Off-grid power Projects

2.2.6 Overview of Methodology 4: Combined Heat and Power Projects

There are two options in this methodology:

- Option A: Where the Baseline Scenario is identified as an existing or alternative CHP plant;
- Option B: Where the Baseline Scenario is identified as a combination of power production and heat production independently of one another.

The approach in each option is described below.

Option A: Where the Baseline Scenario is identified as an alternative CHP plant

The figure below illustrates the steps in this option. In addition to the Baseline Scenario identification and additionality test, it involves the following steps:

- *Step A-5: Identify emission sources in Baseline:* There are three possible sources for emissions in the Baseline –
- those associated with fossil fuel combustion at the Project site;
- those associated with fossil fuel combustion from electricity generation on the network (applicable if the power output of the Project is different from the Baseline, with implications for power supply to the network); and
- those associated with methane release from the decomposition of wood used in the Project (where the Project uses biomass that would otherwise be stockpiled or land filled).
- *Step A-6: Determine Baseline emissions factors:* For emissions from fuel combustion on site, an emissions factor is determined from fuel combustion emissions factors, using only heat output to calculate the emissions factor. For electricity generation on the network, the emissions factor is calculated as the Combined Margin as determined in Annex A. In addition, if methane emissions from decomposition of wood are part of the Baseline, then these are quantified in absolute terms.
- *Step A-7: Identification and determination of leakage:* These are identified but the only type that is quantified is fugitive emissions from natural gas production and transport, in Projects that use natural gas as a fuel, and this is because fugitive gas emissions can be significant contributors to GHG emissions in Russia.
- *Step A-8: Identification of sources of Project emissions:* These are identified as emissions from the combustion of fossil fuels, if any, in the Project.
- *Step A-9: Estimation of Project emissions factors:* The emissions factor for the Project is calculated based on fossil fuel combustion emissions factors, based on Project heat output.
- *Step A-10: Estimation of emission reductions:* Firstly it is necessary to determine the adjusted power output in the Baseline. This is necessary because if heat output in the Project is different from the Baseline, we need to compare power output in the Project with power output in the Baseline, had the Baseline Scenario generated as much heat as in the Project. Hence, the adjusted power output in the Baseline is the Baseline power output multiplied by the ratio of Project heat output to Baseline heat output. There are two cases for determination of emission reductions:

- *Where power output from the Project is at a similar level to the adjusted Baseline power output,* emission reductions are calculated as the product of the Project heat production and the difference between the Project and Baseline emissions factors, plus emission reductions from any avoided methane release.
- *Where power output from the Project is significantly different from the adjusted Baseline power output,* emission reductions are calculated in three parts: Firstly, emission reductions are the product of the Project heat output and the difference in the Baseline and Project fuel combustion emissions factors. Secondly, for any additional power output, the emission reductions are the product of the Combined Margin and the difference between the Project and adjusted Baseline power outputs. Thirdly, there are the emission reductions from any avoided methane release.

Steps 1-4: Baseline Scenario & Additionality Test	Identify Baseline Scenario Check project is additional
Step A-5: Identify emission sources in Baseline	Emissions from fossil fuel combustion at Baseline CHP If output changes, emissions from network generation If use of stockpiled biomass, avoided methane releases
Step A-6: Determine Baseline Emission Factors	Emission factors for Baseline CHP combustion (EFC_b) If power output changes, Combined Margin (CM) If use of stockpiled biomass, avoided methane (BER)
Step A-7: Identify & Determine Leakage	Leakages identified but not quantified
Step A-8: Identify Sources of Project Emissions	Emissions from fossil fuel combustion in Project
Step A-9: Determine Project Emission Factors	Emission factors for fossil fuel combustion in Project (EFC_p)
Step A-10: Determine Emission Reductions	If Project power output same as Baseline: $ERs = (EFC_b - EFC_p) * Q_p + BER$
	If Project power output different from Baseline: $ERs = (EFC_b - EFC_p) * Q_p$ $+ CM * (GEN_p - (GEN_b * Q_p/Q_b)) + BER$

Figure 9 Overview of Methodology 4: CHP Projects Option A

Option B: Where the Baseline Scenario is identified as heat and power produced separately

The figure below illustrates the steps in this option. In addition to the Baseline Scenario identification and additionality test, it involves the following steps:

- *Step B-5: Identify emission sources in Baseline:* There are three possible sources of emissions in the Baseline –
- those associated with fossil fuel combustion for the Baseline heat production;
- if the Baseline power supply is sourced from the network, those associated with fossil fuel combustion from electricity generation on

the transmission network; if the Baseline power supply is sourced from a diesel generator, the emission reductions from diesel in an internal combustion engine;
- those associated with methane release from the decomposition of wood used in the Project (where the Project uses biomass that would otherwise be stockpiled or land filled).
- *Step B-6: Determine Baseline emissions factors:* For emissions from fuel combustion for heat production, an emissions factor is determined from fuel combustion emissions factors. For electricity generation on the network, the emissions factor is calculated as the Combined Margin as determined in Annex A. For diesel power generation, the emissions factor is determined as the emissions factor for diesel in an internal combustion engine of the appropriate size. In addition, if methane emissions from decomposition of wood are part of the Baseline, then these are quantified in absolute terms.
- *Step B-7: Identification and determination of leakage emissions:* These are identified but the only type that is quantified is fugitive emissions from natural gas production and transport, in Projects that use natural gas as a fuel.
- *Step B-8: Identification of sources of Project emissions:* These are identified as emissions from the combustion of fossil fuels, if any, in the Project.
- *Step B-9: Estimation of Project emissions factors:* The emissions factor for the Project is calculated based on fossil fuel combustion emissions factors divided by Project heat output.
- *Step B-10: Estimation of emission reductions:* Emission reductions are calculated in three parts:
- the product of the Project heat production and the difference between the Project and Baseline emissions factor,
- the product of the Baseline power emissions factor (either the Combined Margin or the diesel generation emissions factor), and the Project power output,
- plus emission reductions from any avoided methane release.

Steps 1-5: Baseline Scenario & Additionality Test	Identify Baseline Scenario Check project is additional
Step B-5: Identify emission sources in Baseline	Emissions from fuel combustion at Baseline heat plant Emissions from Baseline power production or network generation If use of stockpiled biomass, avoided methane releases
Step B-6: Determine Baseline Emission Factors	Emission factor for Baseline heat production (EFC_b) Emission factor for diesel generation or combined margin (EFP_b) If use of stockpiled biomass, avoided methane (BER)
Step B-7: Identify & Determine Leakage	Leakages identified but not quantified
Step B-8: Identify Sources of Project Emissions	Emissions from fossil fuel combustion in Project
Step B-9: Estimate Project Emission Factors	Emission factors for fossil fuel combustion in Project (EFC_p)
Step B-10: Estimate Emission Reductions	Emission reductions calculated as: $ERs = (EFC_b - EFC_p) * Q_p + EFP_b * GEN_p + BER$

Figure 10 Overview of Methodology 4: CHP Projects Option B

2.2.7 Overview of the Combined Margin

The Combined Margin is determined as the weighted average of the Operating Margin and the Build Margin. The Operating Margin reflects the emissions factor of the network based on existing generation technologies. The Build Margin reflects the emissions factor of new plants.

Step 1: Determine Operating Margin

The Operating Margin is determined based on the generation weighted average emissions factor of all plant on the network, excluding those plants that are must-run or low cost. The latter include hydro, geothermal, wind, low-cost biomass, nuclear and solar generation facilities. In addition, a portion of the output of CHP plants may be considered as must-run if a portion of the output of such plants is driven by heat demand rather than power demand.

In addition, the emissions factor of CHP plants must be determined based on an allocation of fuel use between the heat and power produced. Fuel requirements for heat production are based on an estimate of the thermal efficiency of the boiler and heat exchanger and the Quantity of heat produced. The remaining fuel is attributed to power production.

Further, the emissions factor for imports should be determined as the Operating Margin of the importing area.

The Operating Margin is determined ex-ante, and may be updated annually.

Step 2: Determine Build Margin

The Build Margin is based on the generated weighted average of the emissions factors of recently built plants on the network. Where few plants have been built in recent years, only those plants identified should be included in the determination of the Build Margin. The Build Margin is determined ex-ante.

Step 3: Determine Combined Margin as weighted average

The Combined Margin is then determined as a weighted average of the Operating Margin and the Build Margin.

The weighting between the Operating Margin and Build Margin should as a default be set to 50/50. Where demand growth has been less than zero in the past five years, the weight for the Build Margin should be set to zero, and the Build Margin need not be determined. Where demand growth has been between zero and 5 per cent per annum, then the weight for the Build Margin should be between zero and 50 per cent (guideline is weight = 10 * growth (%)).

3. Combined Margin for the Arkhanglesk network

This chapter presents a case study applying the Combined Margin methodology as described in Annex A to the Arkhangelsk region of Russia.

3.1 The Arkhangelsk power system

The Arkhangelsk electricity network represents an integrated power system that is connected to the rest of the Russian north west power system. There are a number of power stations supplying the Arkhangelsk network. These include:

- Three CHP plants owned and operated by the Arkhanergo. These plant provide power to the network and heat to local district heating systems;
- A number of independent CHP plants owned and operated by private enterprises – primarily pulp and paper mills. These plants primarily produce to meet the heat and power requirements of the enterprises, but some also sell heat to local district heating systems and several supply power to the network.

Table 2 Characteristics of power plant in Arkhangelsk, 2003

Category	Name	Location	Power capacity	Thermal capacity
		(Town)	MW	Gcal/hr
OAO Arkenergy	Arkhangelsk OAO	Arkhangelsk	450	1167
	Severodivinsk OAO1	Severodvinsk	189	1320
	Severodivinsk OAO2	Severodvinsk	410	1105
	Sub-total		1049	3592
Independent producers	Arkhangelsk PPM 1	Novodinsk	194	929
	Arkhangelsk PPM 2	Novodinsk	12	159
	Arkhangelsk PPM 3	Novodinsk	29	185
	Solombala PPM 1	Arkhangelsk	36	247
	Ark Hydr. Plant *		10	
	Onega Hyr plant *		10	112
	Kotlas PPM HPP1	Koryazhma	305	1800
	Kotlas PPM ETHPS	Koryazhma	48	402
	Sub-total		644	3834
Total			1693	7426

* Not operational

In addition, power is imported into the network from the grid to the south of the Arkhangelsk Oblast. This power is supplied from FOREM – a market for power that operates in north west Russia.

Table 2 and 3 summarise the characteristics of plants in the system. Although the independent producers account for a large share of installed capacity, the bulk of this capacity is used for own-consumption, and is not exported to the grid. In fact, less than 10 per cent of the electricity generation of independent producers is exported to the grid, and this makes up less than 5 per cent of total power supplied to the network.

Table 3 Summary of power generated and supplied to the grid, 2003

Source	Electricity generated		Supplied to grid	
	GWh	%	GWh	%
Arkhangelsk OAO	1 623	23 %	1 623	35 %
Severodivinsk OAO1	792	11 %	792	17 %
Severodivinsk OAO2	781	11 %	781	17 %
Independents	2 534	37 %	193	4 %
Imports	1 199	17 %	1 199	26 %
Total	6 929	100 %	4 589	100 %

3.2 Operating Margin for Arkhangelsk

The Operating Margin is calculated as the weighted average of the emissions factors for the individual plant that are not must-run or low-cost. In the Arkhangelsk context, the power output of the independent generators is taken as must-run as these plants produce primarily for their own needs independently of conditions on the network, and only surplus is provided to the network. That is, this plant can be expected to operate in the same manner regardless of changes to supply on the main grid.

In addition, it is possible that a portion of the power output of the three main CHP plants owned and operated by Arkhenergo can be viewed as must run. This possibility arises due to the fact that a portion of the power output must be produced in order to meet heat demands on local district heating systems. This portion is driven by heat demand rather than power demand, and so the power production is must-run. However, it is difficult to determine this factor, and it is by default set at zero, and treated as sensitivity.

Special consideration must be given to imports as these make up a considerable degree of power supply to the network. Imports are sourced from FOREM. We have determined the Operating Margin for FOREM separately, and included this in the calculation of the Operating Margin for Arkhangelsk.

We have determined the Operating Margin as the annual average emission factor, this is, we have not taken into consideration seasonal or load factor differences. The reason for this is two fold – firstly data availability limits our ability to produce a time-differentiated result, and secondly the results from this calculation will be applied to projects that mainly operate as base load. However, should an application arise where the project, for example, only operate in winter, and then it may be advisable to differentiate the results by summer and winter.

3.2.1 Operating Margin for FOREM

The Operating Margin for FOREM is calculated according to the methodology described in Annex A: The Combined Margin to this report. Supply to FOREM is a mixture of nuclear, hydro and thermal plant, as shown in Table 4.

Table 4 Energy supply to FOREM (GWh)

FOREM	2000	2001	2002	2003	Average	%
Nuclear*	120 909	126 621	131 148	138 754	129 358	43 %
Thermal	88 118	90 747	90 703	96 353	91 480	31 %
Hydro	64 209	67 784	58 289	61 600	62 971	21 %
Other**	20 060	13 633	18 000	11 977	15 918	5 %
Total	293 296	298 785	298 140	308 684	299 726	100%

* From Rosenergoatom,
** Supplied from various Energos .
Source: Ref 1 (FOREM, 2004: www.cdrforem.ru/)

Nuclear and hydro are low-cost or must-run plants, and are excluded for the purpose of determining the Operating Margin. The category listed as “Other” consists of a plants of the utilities (Energos) in different regions. It is difficult to identify which plants or technologies are used for this supply, and given that it comprises only a small portion of the total supply to FOREM, it is excluded from the analysis.

Details are not provided in FOREM of the exact mix of its thermal plants. However, we have assumed that it is the same as the mix of thermal plants in the Russian utility RAO UES (Unified Energy System of Russia) itself – which is a mix of natural gas, coal and fuel oil, in the ratio 68 per cent, 27 per cent, 5 per cent (Ref 2). [10]

RAO UES provides details on specific fuel consumption for different plants. We have grouped these into different fuel types, and determined the average specific fuel consumption (and hence thermal efficiency) for these different categories, as presented below.

[10] In practice, different thermal technologies have different load factors, e.g. coal is typically baseload and oil is typically peaking. However, the methodology applied here does not distinguish between marginal and non-marginal plant at this lvel of detail (only ”must-run” and low cost plant are excluded). Other methodologies are available to obtain a more accurate marginal emissions factor, but these require detailed dispatch data.

Table 5 Specific fuel consumption of plant supplying FOREM

Fuel type	Power plant	Capacity MW	Specific consumption gce/kWh*	Efficiency %	Comment
coal	Berezovskaya TPP-1	1058	341	36 %	
coal	Gusinoozerskaya TPP	1100	360	34 %	
coal	Krasnoyarskaya TPP-2	1100	407	30 %	
coal	Cherepetskaya TPP	1400	412	30 %	
coal	Experimentalnaya TPP		534	23 %	Nesvetay TPP
coal	Bashkirenergo	5071	350	35 %	
coal	Novocherkasskaya TPP	2112	377	33 %	
coal	Jakutsenergo	1133	402	31 %	
Average for coal		**12974**	**371**	**33 %**	
gas	Nevinnomysskaya TPP	1 270	354	35 %	
gas	Permskaya TPP	2 204	305	40 %	
gas	Pechorskaya TPP	1 060	328	37 %	
gas	Pskovskaya TPP	450	334	37 %	
gas	Konakovskaya TPP	2 400	327	38 %	
gas	Severo-Zapadnaya	450	256	48 %	"North-Western CHPP"
gas	Stavropolskaya TPP	2 400	332	37 %	
Average for gas		**10 234**	**324**	**38 %**	
Mixed	Kostromskaya TPP	1 200	309	40 %	Gas/oil (30%/70%)
Mixed	Ryazanskaya TPP	1 060	352	35 %	Coal/gas/oil (40%/30%/30%)
Mixed	Troitskaya TPP	2 500	378	32 %	Gas/oil (20%/80%)
Mixed	Kharanorskaya TPP	700	384	32 %	Coal/oil (70%/30%)
Mixed	Orenburgenergo	3 440	372	33 %	Gas/oil
Mixed	Tumenenergo	2 500			Gas/oil
Average for mixed		**11 400**	**364**	**34 %**	

* gce = grammes of coal equivalent
Source: Ref 2 RAO UES 2003 Annual report, Chapter 8.

Table 6 Parameters used to determine the Operating Margin for FOREM

Plant Name	Unit	Nuclear	Hydro	Natural gas	Coal	Fuel oil	Source
Output	GWh	129 358	62 971	62 206	24 700	4 574	See text above
“Must-run” fraction	%	100 %	100 %	0 %	0 %	0 %	Own estimates
Fuel emissions factor	kg CO2e / GJ	-	-	55,87	93,16	76,84	Section 0
Efficiency	%			38 %	33 %	34 %	Table 5
Emissions factor*	tCO2e / MWh	-	-	0,53	1,01	0,82	Calc-ulated

* Emissions factor = Fuel emissions factor / (Efficiency * 278)

The weighted average emissions factor for FOREM, excluding must-run plants, is hence calculated as 0.67 tCO_2e/MWh using equation A.1b in the Combined Margin Methodology (see Annex A).

There is some uncertainty in the data for the thermal mix of plant supplying FOREM, and so we have conducted a sensitivity analysis on this parameter. Gas is assumed in the above results to have a share of 68 per cent of the mix, and as gas-fired power is the lower emissions factor a more conservative assumption would be to increase the share of gas in the mix. The result for a higher share (75 per cent) of gas-fired plant in FOREM is 0.64 tCO_2e/MWh.

3.2.2 Operating Margin for Arkhangelsk

The Operating Margin for Arkhangelsk is calculated according to the methodology described in the report “Baseline Methodologies for Power and District Heating Sectors”. Table 8 summarises the input data and results.

The total emissions factor (Operating Margin) is then the weighted average of the plant emissions factors, weighted by generation output (excluding any must-run portion of output):

$$\text{Operating Margin} = 0.72\ tCO_2e/MWh$$

Sensitivities with respect to the inflexible portion of output for CHP plants, i.e. parameter M_j, have been undertaken. Varying this factor will alter the weighting between the emissions factor for production in Arkhanglesk with the emissions factor for imports from FOREM. Sensitivity to this factor is minimal as indicated below.

Table 7 Sensitivity of Operating Margin to must-run portion of CHP plant

M_j	0%	25%	50%
Operating Margin	0,72	0,71	0,71

Table 8 Parameters used to determine the Operating Margin for Arkhangelsk

Plant Name		Units	CHP Ark	CHP Sev 1	CHP Sev 2	Imports	Source
Power Output	GEN_j	$\frac{MWh}{yr}$	1 381 772	731 819	781 220	1 199 000	Ref 4
Heat Output	Q_j	$\frac{TJ}{yr}$	12 067	5 876	6 603	N/A	Ref 4
Heat efficiency	EFF_j	%	80 %	80 %	80 %	N/A	Own estimates
Fraction of fuel used for power	P_{ij}	%	50 %	35 %	49 %	N/A	Calcu-lated
"Must-run" fraction	M_j	%	0 %	0 %	0 %	0 %	Own estimates
Fuel Type		Tonnes	Fuel oil	Coal	Fuel oil	N/A	Ref 4
Fuel Consumption	F_{ij}	$\frac{Tonnes}{yr}$	750 000	612 000	400 000	N/A	Ref 4
Calorific Value	CV_i	$\frac{GJ}{unit}$	40,19	18,58	40,19	N/A	Section 0
Fuel emissions factor	$COEF_i$	$\frac{kg\ CO_2e}{GJ}$	76,8	93,2	76,8	N/A	Section 0
Emissions factor		$\frac{tCO_2e}{MWh}$	0,84	0,51	0,77	0,67	Calcu-lated

i = Fuel i
j = Plant j.

3.3 Build Margin

No new plant has been built in Arkhangelsk for at least ten years. Hence, it is not possible to apply the methodology for determining the Build Margin within the project boundary of the Arkhangelsk Oblast. We have thus chosen to use the Build Marign for all of Russia as a proxy for the Build Margin for Arkhangelsk. This choice is justified by the fact that new build in Russia will influence Arkhangelsk through the interconnections that the region has with the rest of Russia.

Despite the fact that electricity consumption in Russia has grown by 8 per cent over the period 1999 to 2003, the country maintains a large surplus capacity. For this reason, there has been little new capacity commissioned in Russia over the past five years. The table below summarises the few instances of new capacity, which accounts for only 0.5 per cent of the 216 GW currently installed capacity in the Russian Federation.

Table 9 New capacity in Russia: 1999–2003

Name	Technology	Year	Capacity (MW)	Energy (GWh)	Fuel type
Severo-Zapadnaya	CCGT	2001	450	3 400	Gas
Burejskaya	Hydro	2003	370	541	Hydro
Nijnevartovskaya	CCGT	2003	800	4 800	Gas
Verhnemutnovskaya	Geothermal	2002	7	28	Renewable
Jantarenergo	Wind	2003	50	200	Renewable
Total			1 727	8 969	

CCGT = Combined Cycle Gas Turbine
Source: Ref 5 (RAO UES, 2004: www.rao-ees.ru/ru/subcomp/)

Emissions are only associated with the plants using gas-fired technologies; the nuclear and renewable plants are assumed to have a zero emissions factor. The efficiency of the gas-fired plants is 48 per cent, based on the specific fuel consumption at the Severo-Zapadnaya station (256 gce/kWh – Ref 7). Given an emissions factor for gas combustion of 55,87 kg CO_2e/GJ, the gas-fired power stations have an emissions factor of 0,428 kg CO_2e/kWh, as shown in Table 10.

Table 10 Emissions factors for each of the Build Margin stations

	Technology/ fuel	Energy generated GWh	Thermal Efficiency %	Emissions factor kgCO_2e/kWh
Severo-Zapadnaya	Natural gas	3 400	48 %	0,419
Burejskaya	Hydro	541	N/A	0,000
Nijnevartovskaya	Natural gas	4 800	48 %	0,419
Verhnemutnovskaya	Geothermal	28	N/A	0,000
Jantarenergo	Wind	200	N/A	0,000

The Build Margin, as the generation weighted average of new plant, is then calculated as 0.38 t CO_2e/MWh.

Natural gas plant make up 91 per cent of the Build Margin. As a sensitivity, doubling the portion of renewable energy in the Build Margin provides a Build Margin estimate of 0.34 t CO_2e/MWh.

3.4 Calculating the Combined Margin

The Combined Margin is calculated as the weighted average of the Operating Margin and Build Margin. The weight for the Build Margin is determined as a multiple of the average annual growth in power demand over the past five years.

Build Margin Weight = 10 * Growth

Growth in electricity consumption on the Arkhangelsk network has averaged 1.7 per cent over the past five years, as shown below; therefore the weight for the Build Margin is 17 per cent, and the weight for the Operating Margin is 83 per cent.

Table 11 Growth in electricity consumption in Arkhangelsk

Year	1998	1999	2000	2001	2002	2003
GWh	2943	3051	3 051	3 055	3 127	3 209
Growth*		3,7 %	1,8 %	1,3 %	1,5 %	1,7 %

* Average annual growth rate since 1998
Source: Ref 6: Arkhaenergo, 2003 Annual Report. http://www.energo.arh.ru/index.php

Using these weights, the Combined Margin is calculated as:

Combined Margin = 83% * 0.72 + 17% * 0,38 = 0.66 t CO_2e/MWh

In the preceding work we have shown some of the sensitivities to uncertain assumptions on the Operating Margin and Build Margin. The influence of using more conservative assumptions for these uncertainties are shown in Table 12. The sensitivity to changes in individual assumptions is small (less than two per cent), and even if all assumptions are changed to conservative ones, the change in Combined Margin is less than five per cent. Hence, the result is considered reasonably robust in relation to key assumptions.

Table 12 Sensitivity of Combined Margin to more conservative assumptions on uncertain data

	Thermal mix in FOREM	Must run portion of CHP	Greater renewable mix in BM	Combined Margin
Basecase				**0,66**
Change from base-case to conservative assumption	✓			0,65
		✓		0,65
			✓	0,65
	✓	✓	✓	0,63

3.5 Data sources for Combined Margin

3.5.1 Data sources referenced

The table below gives sources for data referenced in the preceding text.

Table 13 Data sources for Combined Margin

Ref	Data	Source
1	Energy supplied to FOREM	FOREM, 2004: www.cdrforem.ru/
2	Mix of thermal plant in RAO UES system	RAO UES 2003 Annual report, Chapter 8. Available from http://www.rao-ees.ru/en/business/report2003/8_2.htm
3	Specific fuel consumption for thermal plant in RAO UES	RAO UES 2003 Annual report, Chapter 8. Available from http://www.rao-ees.ru/en/business/report2003/8_2.htm
4	Operating statistics for Arkhaenergo plant & imports.	Arkhaenergo, 2003 Annual Report. http://www.energo.arh.ru/index.php
5	Information on recently built power plant.	RAO UES, 2004 Available from www.rao-ees.ru/ru/subcomp
6	Electricity consumption in Ark-hangelsk Oblast	Arkhaenergo, 2003 Annual Report. http://www.energo.arh.ru/index.php
7	Thermal efficeincy of Severo-Zapadnaya gas-fired power station	www.sztec.ru/about/technology/activities.php

3.5.2 Data for fuel emissions factors

The table below presents assumptions on calorific values, and emissions factors for different fuels.

Table 14 Data for fuel emissions factors

Fuel	Units	Coal tonnes	Data source	Natural gas TJ	Data source	Fuel oil tonnes	Data source
Calorific Value	GJ/fuel unit	18,58	Table 1–2	1000	N/A	40,19	Table 1–3
Carbon content	tC/TJ	25,8	Table 1–1	15,3	Table 1–1	21,1	Table 1–1
Fraction oxi-dised	%	98,0 %	Table 1–6	99,5 %	Table 1–6	99,0 %	Table 1–6
CO_2 emissions	tCO_2/TJ	92,7	Calculated	55,8	Calculated	76,6	Calculated
CH_4 emissions	kg/TJ	1	Table 1–7	1	Table 1–7	3	Table 1–7
N_2O emissions	kg/TJ	1,4	Table 1–8	0,1	Table 1–8	0,6	Table 1–8
CO_2e emis-sions	t CO_2e/TJ	93,2	Calculated	55,9	Calculated	76,8	Calculated

Note: All Data sources refer to IPCC Guidelines Vol 3, 1996 revised.

4. Severoonezsk District Heating

4.1 Introduction

Severoonezsk is a town with a population of 6000 located, in central Archangelsk Oblast, in the Plesetsk District. The main economic activity is derived from the Severoonezsk bauxite mine.

4.1.1 Current heat supply to Severoonezsk

Heat is supplied to the town through a district heating system where heat is produced at oil-fired boilers situated at the mine, 9 km from the settlement. There are two hot-water boilers (PTVM-30M) with an installed capacity of 40MW (34 Gcal/h) and two steam-boilers (DKVR-10/13) with an installed capacity of 10 t/h steam, built in 1970. The main heat network is above ground, consisting of a 9 km pipeline with a pipeline diameter 600mm. Due to excess installed thermal capacity at the boiler house, the average load of the boilers does not exceed 30 per cent, which gives a fairly low thermal efficiency of heat production.

The annual consumption of fuel oil at the settlement is current 6696 t per annum.

4.1.2 Proposed heat supply to Severoonezsk

The Plesetsk District Municipal Administration proposes to build a new hot-water boiler house with a total capacity of 6.0 MW (5.1 Gcal/h) containing two boilers operating on waste wood. This new boiler house will be connected to the existing heat network. A vacant reinforced concrete warehouse will be used for the boiler house.

At present, timber and wood processing enterprises (including private enterprises) located in the vicinity of Severoonezsk produce sufficient quantities of waste wood (chips, shavings, off-cuts, sawdust) to fuel the new boilers. Wood waste will be stored near the boiler house and later will be relocated to a warehouse. A wood chipping machine will also be installed near the boiler house to process off-cuts. Waste wood will be trucked to the boiler house. At present, these wastes are removed to dumps in a forest located some 8 km from the settlement, where they decompose and can sometimes ignite.

The new boiler house will be used primarily for the heating needs of the settlement, and to supplement output of the existing (oil-fired) boiler house. During the summer season only the new boiler house will operate, supplying the settlement with hot water. During the winter season, both the new and existing boiler houses will be in operation, producing thermal energy for both heat and hot water supply. This will allow the existing oil fired boiler house to be shut down for six months of the year (May to September inclusive).

It should be noted that the size of the new boilers (6 MW) will not cover the total heat requirement for the settlement, and is limited by the availability of local waste wood resources. The project owner has identified at least 25 000 t/yr of readily accessible local waste wood production and has entered into contracts with producers of this waste wood. The 6MW capacity therefore represents phase 1 of the project, and a second phase involving biomass boilers could be implemented in the future dependent on availability of fuel resources. The first 6MW boiler house development is therefore based on a conservative estimate of readily available fuel resources. Consequently, under the Project, fuel oil will continue to be consumed in the boilers, and a continuing consumption of 3005 t per annum is expected.

4.1.3 Baseline methodology

The impact on greenhouse gas emissions arising from the project are:

i. Reduction in combustion of fuel oil at the existing boilers;
ii. Reduction in methane emissions from avoided disposal of wood wastes;
iii. Reduction in emissions from power supply to the network, arising from reduced electricity consumption at the heat production system.

For emissions (i) and (ii), the Baseline Methodology used is *7. Methodology 1: District Heating* Projects as presented in Chapter 7. In addition, for emissions under (iii), the *Combined Margin* for the Arkhangelsk network is used.

4.1.4 Project Boundary

The Project Boundary is the existing boiler house and fuel-oil fired boilers that will remain in use during the lifetime of the Project, as well as the proposed new boiler house and wood-waste fired boilers.

4.2 Baseline scenario identification and additionality test

4.2.1 Step 1: Identify set of Alternative Scenarios

There are only two plausible scenarios for the supply of heat to Severoonezsk:

- The current heat supply system: the business-as-usual (BAU) Scenario; and

- The Project Scenario.

An alternative option could be the use of a gas-fired heat production system. However, gas is not available in Severoonezsk and so this option is not plausible.

4.2.2 Step 2: Eliminate Scenarios that face prohibitive barriers

The Project is to be implemented by the Plesetsk District Municipal Administration. The financial performance of the Project is good. The base case analysis shows an IRR of 35 per cent and a payback period of 2.7 years (see Table 15).

Table 15 Financial analysis of Project

Capex	**€ 762 860**				
Fuel	**Change in use**		**Price**	**Financial impact**	
Fuel oil	3005-6696 = (3691)	Tonnes/yr	€104/tonne	€383 864	Saving
Biofuel	26 240	Tonnes/yr	€4,28/tonne	€112 307	Cost
Electricity	(224,7)	MWh/yr	€44,5/tonne	€10 000	Saving
NPV	€879 259	IRR	35%	Payback	2,7 yrs

Source: Ref 1: AOEEC, 2004

With this financial performance, the Project potentially qualifies for a NEFCO loan of up to €350 000 under the Cleaner Production Programme, where one of the criteria is a payback period of less than three years. This implies that over €400 000 must be financed through other sources.

The Municipal Administration, however, is not a credit-worthy entity and is unable to raise finances from other sources. Key items of the Municipal Administration's utility (Uyut-2) financial accounts are presented below. It should be noted that:

- The utility consistently makes an operating loss of between 11 and 21 billion roubles per annum. This implies that Uyut is under-recovering its cost of service by 30 per cent.
- Even after direct subsidies, Uyut continues to have a negative net income of between 1 and 6 billion roubles, before depreciation of assets.
- Accounts receivable in 2003 were in the order of 16 billion roubles, or 126 days receivables. The magnitude of arrears becomes apparent when comparing accounts receivable with the value of fixed assets – arrears are as much as 60 per cent of fixed assets.

Under these circumstances, the Project developer is not a credit worthy institution, and is unable to raise the required finances for implementing this Project.

Table 16 Financial performance of Uyut 2

Balance sheet	2000	2001	2002	2003
Total assets	41 136	41 313	46 078	47 684
Non-current assets	26 992	26 194	24 538	27 394
Fixed assets	26 618	26 003	24 040	26 477
Investments	371	191	498	914
Other	3	-	-	3
Current assets	14 144	15 119	21 540	20 290
Stores & goods	1 141	1 252	8 897	4 278
Accounts receivable	11 639	13 698	10 965	15 616
Other	1 364	169	1 678	396
Capital employed	**41 136**	**41 313**	**46 078**	**47 684**
Equity	16 319	16 356	28 555	29 216
Accounts payable	8 041	5 911	8 275	4 628
Debt to state	16 550	18 454	8 283	12 441
Reserves	226	592	965	1 399

Cash flow	2000	2001	2002	2003
Revenue from sales	17 433	24 773	35 269	45 257
Cost of sales	(29 239)	(41 499)	(48 657)	(66 711)
Operating profit	(11 806)	(16 726)	(13 388)	(21 454)
Subsidies	6 395	16 606	12 637	20 777
Other costs	(330)	(54)	(53)	(218)
Gross income	(5 741)	(174)	(804)	(895)
Taxation	(195)	(633)	(31)	(1 238)
Net income	(5 936)	(807)	(835)	(2 133)

Source: Ref 2: AOEEC, 2004

4.2.3 Step 3: Compare costs of each remaining scenario

Not relevant.

4.2.3 Step 4: Common Practice Analysis

District heating systems in Arkhangelsk are not generally powered by biofuel. In the majority of cases, heat is supplied from CHP technologies that operate on a mix of gas, fuel oil and coal. Examples include:

- *Heat supply to Arkhangelsk town:* This is supplied from the CHP plant owned and operated by Arkhaenergo. This is a 450 MW / 1167 Gcal/hr installation operating on fuel oil.
- *Heat supply to Koryazhama town:* This is supplied from the CHP plant owned and operated by the Kotlas pulp and paper mill. This plant operates on a combination of coal and fuel oil.

Hence, the Project to switch from fuel oil to biofuel is not common practice in the region.

4.3 Baseline emissions

4.3.1 Step 5: Identify sources of emissions in the Baseline Scenario

Emissions in the Baseline Scenario arise from the following sources, as indicated in Table 17. Mobile sources of emissions (i.e. transportation of fuel oil) are not quantified as these are likely to be small contributors to total emission levels.

Table 17 Sources of emissions in the Baseline Scenario

	Emissions	Source	Quantified
1	CO_2, CH_4 & N_2O	Combustion of fuel oil to supply the required heat (stationary combustion)	Yes
2	CO_2	Transportation of fuel oil to the boiler house (mobile combustion)	No
3	CH_4	Decomposition of wood wastes that are currently dumped	Yes
4	CO_2, CH_4 & N_2O	Generation of electricity that will not longer be consumed once the Project is commissioned	Yes

4.3.2 Step 6: Determine Baseline emissions factor

Step 6a: Calculate emissions factor from fuel combustion in the Baseline Scenario

The Baseline emissions factor is determined in accordance with the appropriate equation in the baseline methodology for district heating projects described in Chapter 7. The input data and results are presented in Table 18.

Table 18 Baseline emissions factor

Fuel	Symbol	Units	Fuel oil	Source/comment
Calorific value	CV	GJ/tonne	40,19	IPCC Guidelines Vol 3, Table 1–3, p1.23
Quantity	F	tonnes	6 696	See Table 15
Heat produced	Q	GJ	215 290	Assuming 80% efficiency
Carbon content		tC/TJ	21,1	IPCC Guidelines Vol 3, Table 1–1, p1.13
Fraction oxidised		%	99,0 %	IPCC Guidelines Vol 3, Table 1–6, p1.29
CO_2 emissions	CO2_EFC	TCO_2/TJ	76,6	Calculated
CH_4 emissions	CH4_EFC	kg/TJ	3	IPCC Guidelines Vol 3, Table 1–7, p1.35
N_2O emissions	N20_EFC	kg/TJ	0,6	IPCC Guidelines Vol 3, Table 1–8, p1.36
CO_2e emissions		kg CO_2e/GJ	76,8	Calculated (emissions per GJ of fuel consumed)
Emissions factor	EFC	kg CO_2e/GJ	96,1	Calculated (emissions per GJ of heat produced)

This result is sensitivity to the efficiency of the heat production system. An efficiency of 80 per cent is chosen here as a common benchmark for systems of this nature. Reducing this assumption to 70 per cent increases the emissions factor to 110 kg CO_2e/GJ.

Step 6b: Calculate emissions from stockpiled biomass in the Baseline Scenario

The Project will consume a total of 26 240 tonnes wood waste in the new boilers. This wood waste would otherwise be dumped in landfill and decompose to produce methane. The emissions associated with this methane release can be determined in accordance with the methodology. Table 19 sets out the input data and results.

Step 6c: Calculate Combined Margin

An additional step is added to the Methodology to deal with the reduction in emissions from reduced electricity consumption in the district heating system. The Combined Margin is calculated in accordance with the Combined Margin methodology set out in Annex A of this report.

The Combined Margin is determined to be 0,66 t CO_2e/MWh, as set out in Chapter 3.

Table 19 Emissions associated with decomposition of wood wastes

Wood volumes	26 240	tonnes

Emission series		BER	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Year	Ai	tCO2e/yr	26 240	26 240	26 240	26 240	26 240	26 240	26 240	26 240	26 240	26 240	26 240	26 240	26 240	26 240
0	89	**2 335**	2 335													
1	85	**4 566**	2 230	2 335												
2	81	**6 691**	2 125	2 230	2 335											
3	78	**8 738**	2 047	2 125	2 230	2 335										
4	74	**10 680**	1 942	2 047	2 125	2 230	2 335									
5	71	**12 543**	1 863	1 942	2 047	2 125	2 230	2 335								
6	68	**14 327**	1 784	1 863	1 942	2 047	2 125	2 230	2 335							
7	65	**16 033**	1 706	1 784	1 863	1 942	2 047	2 125	2 230	2 335						
8	62	**17 660**	1 627	1 706	1 784	1 863	1 942	2 047	2 125	2 230	2 335					
9	59	**19 208**	1 548	1 627	1 706	1 784	1 863	1 942	2 047	2 125	2 230	2 335				
10	56	**18 342**	1 469	1 548	1 627	1 706	1 784	1 863	1 942	2 047	2 125	2 230	2 335			
11	54	**17 528**	1 417	1 469	1 548	1 627	1 706	1 784	1 863	1 942	2 047	2 125	2 230	2 335		
12	51	**16 741**	1 338	1 417	1 469	1 548	1 627	1 706	1 784	1 863	1 942	2 047	2 125	2 230	2 335	
13	49	**15 980**	1 286	1 338	1 417	1 469	1 548	1 627	1 706	1 784	1 863	1 942	2 047	2 125	2 230	2 335
14	47	**15 272**	1 233	1 286	1 338	1 417	1 469	1 548	1 627	1 706	1 784	1 863	1 942	2 047	2 125	2 230
	Average:	13 110														

4.4 Emission reductions

4.4.1 Step 7: Estimate Leakage

The only source of leakage identified for the Project is mobile combustion emissions associated with the transportation (by truck) of the wood wastes to the new boiler house. However, these emissions are off-set by the fact that the wood wastes are no longer transported to the landfill dump in the forest.

We are of the view that these emissions are small (less than five per cent) in comparison with other emissions in the Baseline, and so have not quantified them.

4.4.2 Step 8: Identify sources of Project emissions

GHG emissions from the combustion of wood wastesthe Project will continue to use the existing fuel-oil fired boilers on a reduced scale. Hence, combustion emissions will continue under the Project, albeit on a reduced scale in comparison with the Baseline.

4.4.3 Step 9: Estimate Project emissions factors

The emissions factor for the Project is calculated in accordance with the methodology. The data and results are presented in the Table below.

Table 20 Project emissions factor

Fuel	Symbol	Units	Fuel oil	Source/comment
Calorific value	CV	GJ/tonne	40,19	IPCC Guidelines Vol 3, Table 1–3, p1.23
Quantity	F	tonnes	3 005	See Table 15
Heat produced	Q	GJ	215 290	As for Baseline Scenario
Carbon content		tC/TJ	21,1	IPCC Guidelines Vol 3, Table 1–1, p1.13
Fraction oxidised		%	99,0 %	IPCC Guidelines Vol 3, Table 1–6, p1.29
CO_2 emissions	CO_2_EFC	TCO_2/TJ	76,6	Calculated
CH_4 emissions	CH_4_EFC	kg/TJ	3	IPCC Guidelines Vol 3, Table 1–7, p1.35
N_2O emissions	N_20_EFC	kg/TJ	0,6	IPCC Guidelines Vol 3, Table 1–8, p1.36
CO_2e emissions		kg CO_2e/GJ	76,8	Calculated (emissions per GJ of fuel consumed)
Emissions factor	EFC	kg CO_2e/GJ	43,1	Calculated (emissions per GJ of heat produced)

4.4.4 Step 10: Estimate emission reductions

There are three sources of emissions reductions quantified here:

- Emissions reductions from reduced combustion of fuel-oil;
- Emissions reductions from avoiding land-fill of wood wastes;
- Emissions reductions from avoided generation of electricity.

The first set of reductions are calculated as the product of heat production and the difference in Baseline and Project combustion emissions factors. The second is determined directly from Step 6b: Calculate emissions from stockpiled biomass in the Baseline Scenario. The third is determined as the product of electricity savings and the Combined Margin.

The estimated emissions reductions are presented in Table 21. The average annual emissions over the period is 24 657 t CO_2e.

Table 21 Emissions reductions

Year	Heat production	Avoided wood landfill	Avoided power generation	Total
	t CO_2e/yr	t CO_2e/yr	t CO_2e/yr	t CO_2e/yr
1	11 399	2 335	149	13 883
2	11 399	4 566	149	16 113
3	11 399	6 691	149	18 239
4	11 399	8 738	149	20 285
5	11 399	10 680	149	22 227
6	11 399	12 543	149	24 090
7	11 399	14 327	149	25 875
8	11 399	16 033	149	27 580
9	11 399	17 660	149	29 207
10	11 399	19 208	149	30 755
11	11 399	18 342	149	29 889
12	11 399	17 528	149	29 076
13	11 399	16 741	149	28 289
14	11 399	15 980	149	27 528
15	11 399	15 272	149	26 819
Average	11 399	13 110	149	24 657

Heat Production 215 290 GJ/yr AOEEC, 2004
Reduced electricity consumption 224,72 MWh/yr AOEEC, 2004

4.5 Data sources

4.5.1 Data sources referenced

Table 22 gives sources for data referenced in this chapter

Table 22 Data sources for Severoonezsk district heating Project

Ref	Data	Source
1	Financial information on Project given in Table 15	AOEEC 2004. Business Plan. Renovation of the Heat Supply System in Severoonezsk, Plesetsk District, Arkhangelsk Oblast, Section 5
2	Financial information on Uyut-2, given in Table 16	AOEEC 2004. Business Plan. Renovation of the Heat Supply System in Severoonezsk, Plesetsk District, Arkhangelsk Oblast, Annex 3

4.5.2 Data for fuel emissions factors

The table below presents assumptions on calorific values, and emissions factors for fuel oil.

Table 23 Data for fuel emissions factors

Fuel	Symbol	Units	Fuel oil	Data source
Calorific value	CV	GJ/tonne	40,19	Table 1–3, p1.23
Carbon content		tC/TJ	21,1	Table 1–1, p1.13
Fraction oxidised		%	99,0 %	Table 1–6, p1.29
CH4 emissions	CH4_EFC	kg/TJ	3	Table 1–7, p1.35
N2O emissions	N20_EFC	kg/TJ	0,6	Table 1–8, p1.36

Note: All Data sources refer to IPCC Guidelines Vol 3, 1996 revised.

5. Kamenka Combined Heat & Power Plant

5.1 Introduction

The Kamenka settlement in Arkhangelsk Oblast, has a population of approximately 5000 people. The local sawmill at Mezen is the community's main employer.

5.1.1 Current energy supply system

The Kamenka settlement is not connected to the electricity grid; power and heat are produced independently of one another, and independently of the Mezen sawmill, which has its own energy supply system. The key elements of the power and heat supply system in Kamenka and Mezen are summarised below.

- Kamenka settlement
  - There is a set of 14 coal-fired boilers that provide heat to the district heating system in Kamenka.
  - There are three diesel generators (3 x 630 kW) that provide electricity to the isolated grid supplying Kamenka settlement.
- Mezen sawmill
  - There is a CHP plant at the Mezen sawmill that operates on wood wastes. The boiler dates from 1913 and generates both heat and power for use at the sawmill.
  - There is a set of six smaller coal/wood boilers in various locations at the sawmill that generate heat for buildings at the sawmill.

The energy supply system to Kamenka is in poor condition and fails to meet the energy requirements of the community. In general, only one of the three diesel generators is operational at any time, with frequent black-outs. These power cuts affect the operation of the district heating system, which is unable to cope with the heat demand of the settlement. Poor performance is exacerbated by residents switching to electricity for heating purposes when the district heating system is unable to cope with demand, and thereby over-loading the power system.

The CHP installation at the sawmill is old. The boilers date from 1913 and the generator dates from 1927. In the 1980s, a new boiler house was built and the installation of three new boilers as well as a 6 MW turbo generator was started. The installation of the new boilers and generators was not finished, however, and the equipment has since been cannibalized or damaged. The site now consists of a partially completed boiler house and partly installed and damaged boilers and generator.

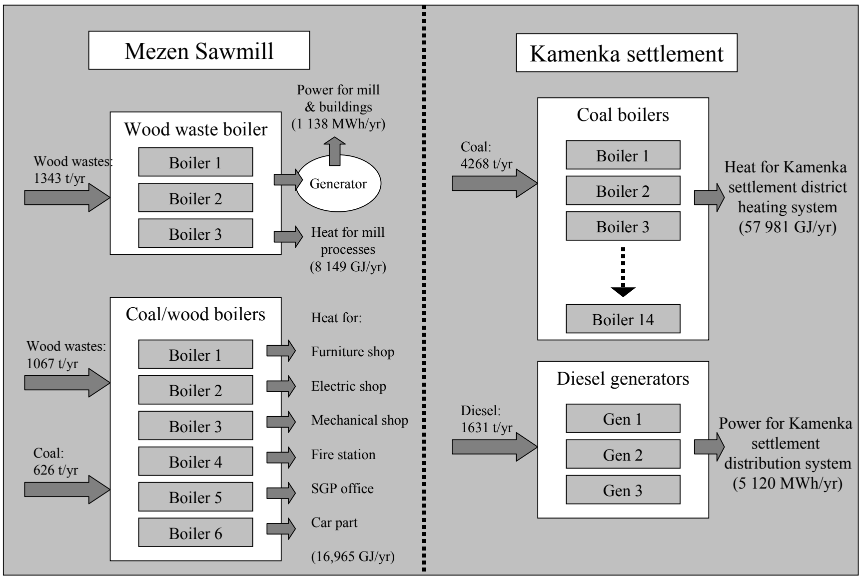

Figure 11 Illustration of existing energy supply to Kamenka settlement and Mezen sawmill

5.1.2 Proposed energy supply system

The proposed Project will install a new CHP system at the Mezen sawmill that will provide heat and power to both the sawmill and Kamenka settlement.

The new installation will have a 6 MW capacity, and will replace a) the existing wood waste boiler at the sawmill, b) most of the existing coal boilers in Kamenka, and c) the diesel generators in Kamenka.

The existing small coal/wood boilers at the sawmill will continue in operation as before, and the coal boilers in Kamenka will continue on a much reduced scale (4 out of 14 boilers remain operational).

It should be noted that the Project will increase the level of energy service to Kamenka, both for electricity and heat. Hence, actual quantities of heat and power production will increase significantly under the Project.

The configuration of energy supply after the Project is implemented is illustrated in

Figure 11.

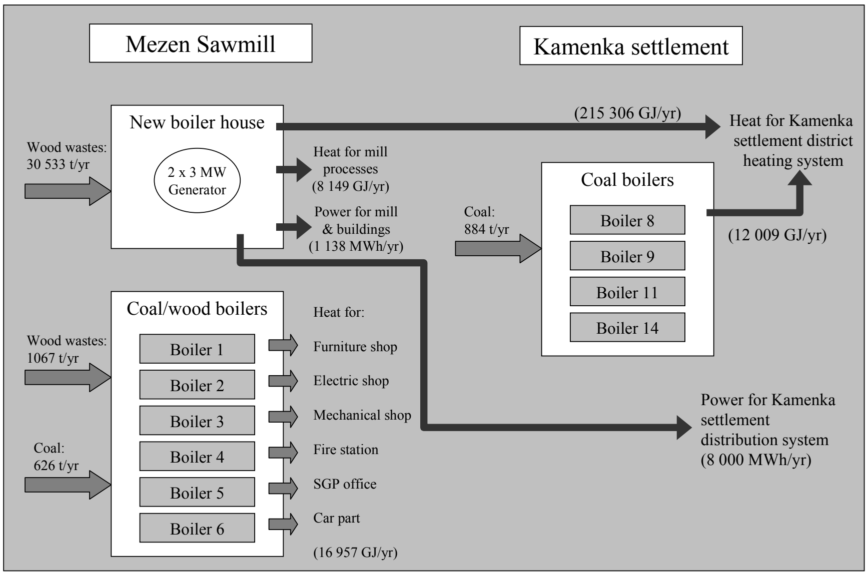

Figure 11 Illustration of proposed energy supply to Kamenka settlement and Mezen sawmill

5.1.3 Baseline methodology

Under the Project scenario, emissions for supply of heat and power to the sawmill will not change from the Baseline scenario. This is because the coal/wood boilers at the sawmill will continue in use as before; the sawmills existing CHP plant operates on wood wastes, and so is already a zero emission system.

Hence, from an emissions reduction viewpoint, the Project replaces coal-fired boilers and the diesel generators (both in Kamenka) with output from the new CHP plant at the Mezen sawmill. This means that only quantities of fuel and energy supply for Kamenka need be considered in the Baseline and Project to determine emissions reductions.

Table 24 summarises the key fuel and energy quantities for the Baseline and Project.

Table 24 Fuel quantities and energy supplied

Location	Fuel	Units	Baseline	Project
Mezen CHP	Biofuel	Tonnes/yr	1343	30 533
Mezen boilers	Wood	Tonnes/yr	1067	1067
	Coal	Tonnes/yr	626	626
Kamenka boilers	Coal	Tonnes/yr	4268	884
Kamenka generators	Diesel	Tonnes/yr	1631	0
Location	**Product**	**Units**	**Baseline**	**Project**
Mezen	Process heat	GJ/yr	8 149	8 149
	Heat for buildings	GJ/yr	16 965	16 965
	Electricity	MWh/yr	1 138	1 138
Kamenka	Heat	GJ/yr	57 981	227 315
	Electricity	MWh/yr	5 120	16 452

Source: Ref 1. IRIS environmental systems inc. Biomass Renewable Energy JI Project – Kamenka, Arkjangelsk Region, Russia

The Baseline Methodology utilised is *Methodolygy 4: Combined Heat and Power Projects (Option B)* as presented in Chapter 10.

5.1.4 Project Boundary

The Project Boundary includes the following:

- The proposed CHP plant at the Mezen Sawmill;
- The four coal-fired boilers in Kamenka used to supply heat that will remain operational after the new CHP plant is commissioned

5.2 Baseline scenario identification and additionality test

5.2.1 Step 1: Identify set of Alternative Scenarios

There are two plausible scenarios for supply of heat and energy to Kamenka settlement:

- The BAU Scenario: Continuation of the current energy supply system based on separate production of heat (from coal) and power (from diesel);
- The Project Scenario: Implementation of a biofuel powered CHP plant at Mezen sawmill, supplying heat and power to Kamenka settlement.

5.2.2 Step 2: Eliminate Scenarios that face prohibitive barriers

The Kamenka municipality and Mezen sawmill face constraints in raising capital for this type of project. However, the additionality argument is primarily based on the financial returns of the project, as described below.

5.2.3 Step 3: Compare costs of each remaining scenario

Given that there are only two scenarios, we have compared the changes in costs and revenues between the two scenarios. Financial impacts arise from the following:

- Capital costs of investment;
- Increased operating and maintenance costs of a larger system;
- Reduced diesel purchases for power generation in Kamenka settlement;
- Reduced coal purchases for heat production in Kamenka settlement;
- Increased cost of water purchases;

- Increased revenue from sales of additional electricity;
- Increased revenue from sales of additional heat.

The key assumptions for these calculations are presented in Table 25. We have also assumed an 80 per cent collection rate for sales of heat and power. A capital investment of €4.8 million will result in a net annual positive cash flow of €640 000. Over a 10 year period, this gives an IRR of 5,6 per cent, which is below the usual rate of return requirements for this type of investment.

Table 25 Assumptions for financial analysis

Capital costs	€4 819 000		Increased opex		€97 000 / yr
			Increased maintenance		€86 200 / yr
Fuel	**Price**		**Quantities**		**Financial impact**
Diesel price	€ 104	/tonne	1 631	tonnes/yr	€ 169 624 / yr
Coal price	€ 10,00	/tonne	3 384	tonnes/yr	€ 33 840 / yr
Biofuel price	€ 2,40	/tonne	29 190	tonnes/yr	-€ 70 056 / yr
Water price	€ 0,02	/m3	5 000 000	m3/yr	-€ 100 000 / yr
Increased kWh sales	€ 32,00	/MWh	11 332	MWh/yr	€ 362 631 / yr
Increased heat sales	€ 3,70	/GJ	169 334	GJ/yr	€ 627 059 / yr

Source: Table 24 and Ref 2: Business Plan, Combined heat and power based on biofuel, Kamenka, Mezen Municipality, Arkhangelsk Oblast

The result is robust to changes in price information. Table 26 presents the changes in the IRR for a 20 per cent change in price assumption. The largest response is to heat prices, but even so the IRR remains below 10 per cent in all cases. Consequently, we conclude that the BAU Scenario is the Baseline Scenario.

Table 26 Sensitivity of results to price assumptions

Price	Assumption		Change	IRR	Change in IRR
Diesel	€ 104	/tonne	20%	6,7%	1,1%
Coal	€ 10,00	/tonne	20%	5,8%	0,2%
Biofuel	€ 2,40	/tonne	(20%)	6,1%	0,5%
Water	€ 0,02	/m3	(20%)	6,3%	0,7%
Power	€ 32,00	/MWh	20%	7,4%	1,8%
Heat	€ 3,70	/GJ	20%	8,7%	3,1%

5.2.4 Step 4: Common Practice Analysis

District heating and power systems in Arkhangelsk are not powered by biofuel. In the majority of cases, heat is supplied from combined heat and power technologies (CHP) that operate on a mix of gas, fuel oil and coal. Examples include:

- *Heat supply to Arkhangelsk town:* This is supplied from the CHP plant owned and operated by Arkhaenergo. This is a 450 MW / 1167 Gcal/hr installation operating on fuel oil.
- *Heat supply to Koryazhama town:* This is supplied from the CHP plant owned and operated by the Kotlas pulp and paper mill. This plant operates on a combination of coal and fuel oil.

The majority of off-grid power supply systems are diesel generators, operated by OblDES, which has 100 stations operating in 50 settlements in Archangelsk.

Hence, the Project to switch from diesel generators and coal heat production to biofuel is not common practice in the region.

5.3 Baseline emissions

Option B of the Baseline methodology for CHP projects given in Chapter 10 is used.

5.3.1 Step B-5: Identify sources of emissions in the Baseline Scenario

Emissions in the Baseline Scenario arise from the following sources, as indicated in Table 6.4. Not all sources of emissions are quantified – those associated with the transportation of diesel fuel and coal to the site are not quantified as these contribute only a small proportion of total emissions (less than 5 per cent).

Table 27 Sources of emissions in the Baseline Scenario

	Emissions	Source	Quantified
1	CO_2, CH_4 & N_2O	Combustion of coal to supply the required heat to Kamenka (stationary combustion)	Yes
2	CO_2	Transportation of coal to the boiler house (mobile combustion)	No
3	CO_2 CH_4 & N_2O	Combustion of diesel to supply the required electricity to Kamenka (stationary combustion)	Yes
4	CO_2	Transportation of diesel to the diesel generators (mobile combustion)	No
5	CH_4	Decomposition of wood wastes that are currently landfilled	Yes

5.3.2 Step B-6: Determine Baseline emissions factor

Step B-6a: Calculate emissions factor from fuel combustion for heat production in the Baseline Scenario

The Baseline Emissions factor for heat production is determined in accordance with the equation in the methodology. The input data and results are presented below.

Table 28 Baseline emissions factor for heat production

Fuel	Symbol	Units	Coal	Source/comment
Calorific value	CV	GJ/tonne	20,2	Local values, Ref 1.
Quantity	F	tonnes	4 268	See Table 24
Heat produced	Q	GJ	60 500	See Table 24
Carbon content		tC/TJ	25,8	IPCC Guidelines Vol 3, Table 1–1, p1.13
Fraction oxidised		%	98,0 %	IPCC Guidelines Vol 3, Table 1–6, p1.29
CO_2 emissions	CO_2 EFC	tCO_2/TJ	92,7	Calculated
CH_4 emissions	CH_4_EFC	kg/TJ	1	IPCC Guidelines Vol 3, Table 1–7, p1.35
N_2O emissions	N_20_EFC	kg/TJ	1,4	IPCC Guidelines Vol 3, Table 1–8, p1.36
CO_2e emissions		kg CO_2e/GJ	93,2	Calculated (emissions per GJ of fuel consumed)
Emissions factor	EFC	kg CO_2e/GJ	132,76	Calculated (emissions per GJ of heat produced)

Sensitivity analyse of this result has not been undertaken since the data inputs to the calculations are known with a high degree of certainty.

Step B-6b: Calculate emissions factor for electricity generation in the Baseline Scenario

Electricity is generated from three diesel generators, 630 kW each. The Baseline emissions factor for power production is determined in accordance with the equation given in the Baseline methodology for CHP projects given in Chapter 10. The input data and results are presented in Table 29.

Table 29 Baseline emissions factor for power generation

Fuel	Symbol	Units	Coal	Source/comment
Calorific value	CV	GJ/tonne	43,33	IPCC Guidelines Vol 3, Table 1–3, p1.23
Quantity	F	tonnes	1 631	See Table 24
Power produced	GEN	MWh	5 120	See Table 24
Carbon content		tC/TJ	20,2	IPCC Guidelines Vol 3, Table 1–1, p1.13
Fraction oxidised		%	99,0 %	IPCC Guidelines Vol 3, Table 1–6, p1.29
CO_2 emissions	CO_2_EFC	t CO_2/TJ	73,3	Calculated
CH_4 emissions	CH_4_EFC	kg/TJ	3	IPCC Guidelines Vol 3, Table 1–7, p1.35
N_2O emissions	N_20_EFC	kg/TJ	0,6	IPCC Guidelines Vol 3, Table 1–8, p1.36
CO2e emissions		$\frac{\text{kg } CO_2e}{\text{GJ}}$	73,6	Calculated (emissions per GJ of fuel consumed)
Emissions factor	EFC	$\frac{\text{kg } CO_2e}{\text{MWh}}$	1,02	Calculated (emissions per MWh of electricity produced)

Sensitivity analyse of this result has not been undertaken since the data inputs to the calculations are known with a high degree of certainty.

Step B-6c: Calculate emissions from stockpiled biomass in the Baseline Scenario

The Project will increase the use of wood in energy supply from the current level of 2 410 to 31 600 tonnes/year – and increase of 29 190 tonnes per year. This additional wood material would otherwise have been dumped in landfill sites and left to decompose to produce methane. The emissions associated with this methane release can be determined in accordance with the methodology. The table below sets out the input data and results.

Table 30 ***Emissions associated with decomposition of wood wastes***

Wood volumes		29 190	tonnes

Emission series		**BER**	1	2	3	4	5	6	7	8	9	10	11	12	13
Year	Ai	**tCO2e/yr**	29 190	29 190	29 190	29 190	29 190	29 190	29 190	29 190	29 190	29 190	29 190	29 190	29 190
0	89	**2 598**	2 598												
1	85	**5 079**	2 481	2 598											
2	81	**7 443**	2 364	2 481	2 598										
3	78	**9 720**	2 277	2 364	2 481	2 598									
4	74	**11 880**	2 160	2 277	2 364	2 481	2 598								
5	71	**13 953**	2 072	2 160	2 277	2 364	2 481	2 598							
6	68	**15 938**	1 985	2 072	2 160	2 277	2 364	2 481	2 598						
7	65	**17 835**	1 897	1 985	2 072	2 160	2 277	2 364	2 481	2 598					
8	62	**19 645**	1 810	1 897	1 985	2 072	2 160	2 277	2 364	2 481	2 598				
9	59	**21 367**	1 722	1 810	1 897	1 985	2 072	2 160	2 277	2 364	2 481	2 598			
10	56	**20 404**	1 635	1 722	1 810	1 897	1 985	2 072	2 160	2 277	2 364	2 481	2 598		
11	54	**19 499**	1 576	1 635	1 722	1 810	1 897	1 985	2 072	2 160	2 277	2 364	2 481	2 598	
12	51	**18 623**	1 489	1 576	1 635	1 722	1 810	1 897	1 985	2 072	2 160	2 277	2 364	2 481	2 598
13	49	**17 777**	1 430	1 489	1 576	1 635	1 722	1 810	1 897	1 985	2 072	2 160	2 277	2 364	2 481
14	47	**16 989**	1 372	1 430	1 489	1 576	1 635	1 722	1 810	1 897	1 985	2 072	2 160	2 277	2 364
	Average:	14 583													

5.4 Emission reductions

5.4.1 Step B-7: Estimate Leakage

A source of leakage identified for the Project is mobile combustion emissions associated with the transportation (by truck) of the wood wastes to the new boiler house. However, these emissions are off-set by the fact that the wood wastes are no longer transported to the landfill dump in the forest.

We are of the view that these emissions are small in comparison with other emissions in the Baseline, and so have not quantified them.

Another source of leakage for the Project is mobile combustion emissions associated with transportation of coal to the boilers that will continue to provide heat to the district heating system in Kamenka. However, it should be noted that there will be similar and greater emissions in the Baseline, which have not been quantified due to their small contribution to total emissions. Omitting these emissions from both the Baseline and the Project will underestimate the quantity of emissions reductions (since these emissions are greater in the Baseline than in the Project due to greater coal quantities in the Baseline) and so is conservative.

5.4.2 Step B-8: Identify sources of Project emissions

While GHG emissions from combustion of wood wastes do not contribute to climate change, the Project will continue to use the existing coal-fired boilers on a reduced scale. Hence, combustion emissions will continue under the Project, albeit on a reduced scale in comparison with the Baseline.

5.4.3 Step B-9: Estimate Project emissions factors

The emissions factor for the Project is calculated in accordance with the methodology. The data and results are presented in Table 31 below.

Table 31 Project emissions factor

Fuel	Symbol	Units	Coal	Source/comment
Calorific value	CV	GJ/tonne	20,2	Local values, Ref 1.
Quantity	F	tonnes	884	See Table 24
Heat produced	Q	GJ	227 315	See Table 24
Carbon content		tC/TJ	25,8	IPCC Guidelines Vol 3, Table 1–1, p1.13
Fraction oxidised		%	98,0 %	IPCC Guidelines Vol 3, Table 1–6, p1.29
CO_2 emissions	CO_2_EFC	tCO_2/TJ	92,7	Calculated
CH_4 emissions	CH_4_EFC	kg/TJ	1	IPCC Guidelines Vol 3, Table 1–7, p1.35
N_2O emissions	N_2O_EFC	kg/TJ	1,4	IPCC Guidelines Vol 3, Table 1–8, p1.36
CO2e emissions		kg CO_2e/GJ	93,2	Calculated (emissions per GJ of fuel consumed)
Emissions factor	EFC	kg CO_2e/GJ	6,73	Calculated (emissions per GJ of heat produced)

The project emissions factor is sensitive to the quantity of coal that is retained in the fuel mix. The coal consumption at the Kamenka settlement has been assumed to reduce from 4268 t/year to 884 t/year once the project is operational – a reduction of 80 per cent. If the reduction is less than this due to, for example, constraints in biofuel supply, then the project emissions fact or will be higher. A reduction of 60 per cent coal use will give a project emissions factor of 19,5 kg CO_2e/GJ.

5.4.4 Step B-10: Estimate emission reductions

There are three sources of emissions reductions quantified here:

- Emissions reductions from reduced combustion of coal;
- Emissions reductions from avoided generation of electricity from diesel generators;
- Emissions reductions from avoiding land-fill of wood wastes.

Table 32 Emissions reductions

Heat production	**227 315**	**GJ/yr**	**See Table 24**
Electricity production	**16 452**	**MWh/yr**	**See Table 24**

Year	Heat production t CO_2e/yr	Power production t CO_2e/yr	Avoided wood landfill t CO_2e/yr	Total t CO_2e/yr
1	28 648	8 124	2 598	39 370
2	28 648	8 124	5 079	41 851
3	28 648	8 124	7 443	44 216
4	28 648	8 124	9 720	46 493
5	28 648	8 124	11 880	48 653
6	28 648	8 124	13 953	50 725
7	28 648	8 124	15 938	52 710
8	28 648	8 124	17 835	54 607
9	28 648	8 124	19 645	56 417
10	28 648	8 124	21 367	58 139
11	28 648	8 124	20 404	57 176
12	28 648	8 124	19 499	56 271
13	28 648	8 124	18 623	55 396
14	28 648	8 124	17 777	54 549
15	28 648	8 124	16 989	53 761
Average	28 648	8 124	14 583	51 356

The first set of reductions are calculated as the product of heat production and the difference in Baseline and Project combustion emissions factors. The second is determined as the product of electricity consumption and the Baseline emissions factor for electricity generation. The third is determined directly from Step B-6c: Calculate emissions from stockpiled biomass in the Baseline Scenario.

Table 32 presents the estimate of emission reductions for the Project. The average annual emission reductions over a 15 year period is 51 000 t CO_2e. If the more conservative estimate is used for project emissions, this estimate will reduce to 48 000 t CO_2e. It is important that the monitoring protocol correctly measure the heat outputs and fuel quantities to address this uncertainty.

5.5 Data sources

5.5.1 Data sources referenced

The table below gives sources for data referenced in the preceding text.

Table 33 Data sources for Severoonezsk district heating Project

Ref	Data	Source
1	Technical information on Project given in Table 24	IRIS environmental systems inc. Biomass Renewable Energy JI Project – Kamenka, Arkjangelsk Region, Russia, derived from p37
2	Project capital costs and fuel cost assumptions given in Table 25	Business Plan. Combined heat and power based on biofuel. Kamenka, Mezen Municipality, Arkhangelsk Oblast

5.5.2 Data for fuel emissions factors

The table below presents assumptions on calorific values, and emissions factors for fuel oil.

Table 34 Data for fuel emissions factors

	Symbol	Units	Coal	Data source
Calorific value	CV	GJ/tonne	20,2	Ref 1
Carbon content		tC/TJ	25,8	Table 1–1, p1.13
Fraction oxidised		%	98,0 %	Table 1–6, p1.29
CH4 emissions	CH4_EFC	kg/TJ	1	Table 1–7, p1.35
N2O emissions	N20_EFC	kg/TJ	1,4	Table 1–8, p1.36

	Symbol	Units	Diesel	Data source
Calorific value	CV	GJ/tonne	43,33	Table 1–3, p1.23
Carbon content		tC/TJ	20,2	Table 1–1, p1.13
Fraction oxidised		%	99,0 %	Table 1–6, p1.29
CH4 emissions	CH4_EFC	kg/TJ	3	Table 1–7, p1.35
N2O emissions	N20_EFC	kg/TJ	0,6	Table 1–8, p1.36

Note: All Data sources refer to IPCC Guidelines Vol 3, 1996 revised.

6. OblDES grid connection

6.1 Introduction

The OblDES (State Unitary Enterprise “Arkhangelsk Oblast Energy Company”), which is owned by the Oblast, was established in 2003 and is responsible for the supply and distribution of electricity to approximately 30 000 people living in seven of the more remote areas (Raions) in the northeast of the Oblast, as shown in Table 35.

Table 35 Summary of OblDES generation areas

Raion	Population Served	Installed Capacity (MWe)	Electricity Generated (GWh)	Plant Factor (%)	System Losses (%)
Leshukonsky	10 889	11,7	18,1	18%	32%
Mezensky	6 845	9,3	11,3	14%	11%
Pinezhsky	3 534	2,7	5,4	23%	20%
Primorsky	1 689	3,7	2,6	8%	12%
Solovetsky	970	2,9	3,5	14%	11%
Verkhnetoemsky	3 628	4,0	3,1	9%	21%
Vinogradovsky	973	0,3	1,3	49%	19%
TOTAL	28 528	35	45	15 %	21 %

Source: Jacobs Gibb, 2004: Small-scale diesel power stations modernisation in Arkhangelsk Oblast, p30

Much of the equipment the OblDES inherited is old, inefficient and in some instances, not appropriate to the power demands of the supply area, leading to low levels of energy efficiency and high costs of supply. OblDES is developing a programme to modernise its generating installations.

One option for several settlements is to establish a localised grid and interconnect this to the main network in Arkhangelsk. This would displace diesel generation with purchases from the network.

6.1.1 Current power supply in Primorsky Raion

The Primorsky Raion is supplied by OblDES (see Table 36), and it is possible to interconnect several of the settlements and connect to the grid.

6.1.2 Proposed power supply in Primorsky Raion

The proposed system would create a single network interconnecting the following settlements: Krasnaya Gora, Pertominsk, Lopshenga, L Zolotitsa, Pushlakhta, Luda and Una. The interconnection would serve around 1,400 (6% of the population served by OblDES).

Table 36 OblDES operations in Primorsky Raion

Generation Station	Population	Installed Capacity (kWe)	Generated (GWh)	Sold (GWh)
N Zolotitsa	310	1120	0,82	0,68
Pertominsk	404	980	1,02	0,90
Lopshenga	500	740	0,37	0,37
Luda [1]	85	210	0,18	0,16
Una [1]	82	150		
L Zolotitsa [2]	185	200	0,22	0,18
Pushlakhta [2]	85	80		
Krasnaya Gora [3]	21	68	0,02	0,02
Krasnoye [3]	14	40		
TOTAL	1 689	3 588	2,63	2,31

1 Generation and consumption data is not separately available for Una and Luda.
2 Generation and consumption data is not separately available for L Zolotitsa and Pushlakhta.
3 Generation and consumption data is not separately available for Krasnaya Gora and Krasnoye.

Source: Jacobs Gibb, 2004, p35

It is proposed that the system could be connected to the OAO Arkhenergo system linking into the existing 35 kV from Severodvinsk to Onega. In the absence of the project, the existing generation capacity of around 2.5 MW would continue to be utilised to meet the projected load.

Although the current load in these seven settlements is 1,6 GWh per annum, it is anticipated that with a better quality supply demand could increase to 3,7 GWh per annum. The required works comprise:

- 200 km of 10 kV line;
- 2 breakers;
- 1 x 35 / 10 kV step down transformer;
- 7 x 10 kV / 400 V step down transformers for supplies to settlements to be connected.

The estimated capital cost is around € 2.5 million (RUR 90 million).

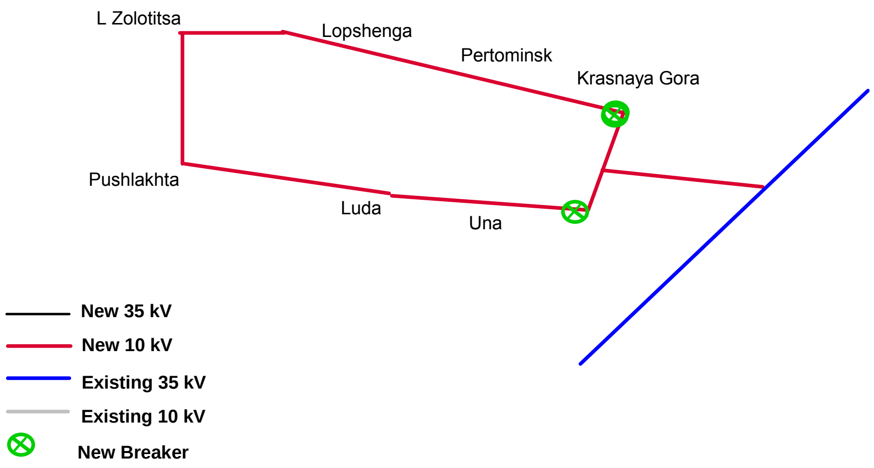

Figure 12 Proposed interconnection of settlements and to main grid (not to scale)

6.1.3 Baseline methodology

The project will replace an isolated grid system with a connection to the main transmission network. Emissions from diesel generators will be replaced with emissions from power supply to the general network in Arkhanglesk.
The Baseline Methodology utilised is *9. Methodology 3: Off-grid power* Projects as presented in Chapter 9.

6.1.4 Project Boundary

The Project Boundary is taken as the network supplying the seven settlements of Krasnaya Gora, Pertominsk, Lopshenga, L Zolotitsa, Pushlakhta, Luda and Una.

6.2 Baseline scenario identification and additionality test

6.2.1 Step 1: Identify set of Alternative Scenarios

There are two plausible scenarios for supply of power to these settlements:

- The BAU Scenario: Continuation of the current power supply system based on diesel generation;
- The Project Scenario: Implementation of a local network to all seven settlements, and interconnected to the main grid.

6.2.2 Step 2: Eliminate Scenarios that face prohibitive barriers

OblDES faces constraints in raising capital for this type of project. However, the additionality argument is primarily based on the financial returns of the project, as described below.

6.2.3 Step 3: Compare costs of each remaining scenario

Costs for each scenario are organised in three categories:

Capital costs	In the BAU Scenario, there are costs of refurbishment of diesel generators	In the Project Scenario, there are costs of grid interconnection
Operating costs	In the BAU Scenario, there are operating costs associated with diesel generators as well as customer service and network maintenance	In the Project Scenario, reduced operating costs associated with customer service and network maintenance
Energy supply costs	In the BAU Scenario, there are costs of diesel fuel	In the Project Scenario, power purchases from grid

The assumptions for each of these cost categories are summarised in Table 37:

Table 37 Cost assumptions

	BAU Scenario	Project Scenario
Capital costs	€ 240 000	€ 2 460 000
Operating costs	€ 142 393 per year[1]	€ 14 500 per year[2]
Electricity supply costs	Diesel costs of €340/tonne at a diesel consumption of 0,33 kg/kWh[3]	Grid purchase price of €30/MWh [4]

1 Based on operating costs of OblDES in the Primorsky Raion, as reported in Jacobs Gibb, 2004, p 158.
2 Own estimates based on avoided costs of operating diesel generators.
3 Based on a thermal efficiency of 25 per cent, typical for small-scale diesel generators.
4 Estimates utilised in Jacobs Gibb for evaluating grid interconnections.

Using a discount rate of 15 per cent, the results of the analysis show that the BAU Scenario has lower costs than the Project, as summarised in Table 38. This implies that the BAU Scenario is the Baseline Scenario.

Table 38 Results of cost comparison

	BAU Scenario	Project Scenario
Capital costs	€ 240 000	€ 2 460 000
Annual operating costs	€ 561 000	€125 000
PV of costs	€2.6 mill	€2.7 mill
Unit costs	€71/MWh	$72/MWh

The results are sensitive to key assumptions, particularly on the cost of diesel fuel and the price of electricity from the network. However, these sensitivities confirm that it is a high risk project for OblDES and hence has not been prioritised by them for implementation.

6.2.4 Step 4: Common Practice Analysis

OblDES has not implemented any grid connections since its establishment. The study into investment opportunities for OblDES (Jacobs Gibb, 2004) identified several such interconnection possibilities, but none were prioritised for investment.

6.3 Baseline emissions

6.3.1 Step 5: Identify sources of emissions in the Baseline Scenario

The sources of emissions in the Baseline are emissions from the generation of electricity in diesel generators.

6.3.2 Step 6: Determine Baseline emissions factor

The baseline emissions factor is based on the standard emissions factors provided in the Baseline Methodology for off-grid power projects described in chapter 9.

Each settlement in the Raion uses different sized generators (all load factors are below 25 per cent), and hence a different standard emissions factor may apply to each generator. For each settlement, we have determined an average emissions factor based on the mix of generators. The weighted average of these emissions factors (weighted by historical generation in each settlement) has then been taken as the Baseline emissions factor. The results are shown in Table 39, giving a baseline emissions factor of 1,23 t CO_2e/MWh.

Table 39 Emissions factors for diesel generators

Generation	Generated	Load	Emissions factor based on generator size						Ave
station	GWh	factor	No	Size	EF	No	Size	EF	EF
Pertominsk	1,02	12 %	1	50	1,3				1,30
Lopshenga	0,37	6 %	1	100	1,3	2	320	0,8	0,87
uda	0,09	5 %	2	50	1,3	1	100	1,3	1,30
Una	0,09	7 %	1	50	1,3	1	100	1,3	1,30
L Zolotitsa	0,15	9 %	2	50	1,3	1	100	1,3	1,30
Pushlakhta	0,07	10 %	1	30	1,9	1	50	1,3	1,53
Krasnaya Gora	0,02	3 %	1	30	1,9	1	37,5	1,9	1,90
Total	1,81	9 %	Weighted emissions factor:						1,23

EF = Emissions factor in units kg CO_2 e / kWh

The load factors of the generators is low, although probably relates to periods when the generators do not run rather than operating at low capacity factors. Even so, if capacity factors are considerably below 25 per cent, the standard emissions factors at the 25 per cent load factor may be under-estimates. However, in this context taking the 25 per cent factor is conservative, and so the result is conservative with respect to load factors.

6.4 Emission reductions

6.4.1 Step 7: Estimate Leakage

No leakages are identified or quantified for the Project.

6.4.2 Step 8: Identify sources of Project emissions

Emissions in the Project will arise from emissions associated with the generation of electricity for the integrated network.

6.4.3 Step 9: Estimate Project emissions factors

The emissions factor for the Project is the Combined Margin for the network in Arkhangelsk. As shown in Chapter 3 this is 0,66 t CO_2e / MWh.

6.4.4 Step 10: Estimate emission reductions

Emissions reductions are a function of actual consumption in the settlements. A demand forecast of 3.7 GWh has been prepared by Jacobs Gibb (2004), and this is applied to the difference in Baseline and Project emissions factors to arrive at an annual reduction in emissions of 2 092 t CO_2e per annum.

Emissions reductions =

= (Baseline EF – Project EF) * Consumption

= (1,23 – 0,66) t CO_2e/MWh * 3700 MWh = 2 092 t CO_2e per annum

It should be noted that since the consumption forecast rather than historical consumption is used to estimate the emission reductions, this is an example where suppressed demand is included.

6.5 Data sources

Jacobs Gibb, 2004: Small-scale diesel power stations modernisation in Arkhangelsk Oblast.

7. Methodology 1: District Heating Projects

7.1 Applicability

This methodology is applicable to Projects that:

- Establish a new district heating system that does not sell power; or
- Change fuel use at an existing district heating system; or
- Expand the operation at an existing district heating system; or
- Improve the efficiency of heat distribution in a district heating system; or
- Any combination of the above.

This methodology applies to Projects in Russia and the Baltic States, as well as other similar operating environments.

7.2 Project Boundary

The Project Boundary is taken to be the equipment and facilities used to produce heat for distribution through a district heating network. This includes the fuel handling facilities at the heating installation, the boiler houses, boilers and heat exchange system. In cases where the Project also includes investments in the efficiency of the heat distribution system, then the Project boundary also includes this distribution system.

For assessing Project emissions, the Project boundary will include GHG emissions from the combustion of fossil fuels for heat production at the Project site.

For the Baseline determination, only account GHG emissions from the combustion of fossil fuels for heat production that is displaced due to the Project.

7.3 Additionality and Baseline Scenario Selection

Step 1: Identify the set of Alternative Scenarios

Identify realistic and credible alternative(s) that provide outputs or services comparable with the proposed JI Project. These alternative scenarios should include: