



**Project design document form
(Version 10.1)**

Complete this form in accordance with the instructions attached at the end of this form.

BASIC INFORMATION

Title of the project activity	Conversion of Pars 1 power plant from single cycle to combined cycle
Scale of the project activity	<input checked="" type="checkbox"/> Large-scale <input type="checkbox"/> Small-scale
Version number of the PDD	02
Completion date of the PDD	01/03/2018
Project participants	1. National Iranian Oil Company (NIOC) 2. Pars Oil and Gas Company (POGC) 3. Farab Company 3. Mehr Renewable Energies Company
Host Party	Iran
Applied methodologies and standardized baselines	ACM0007, version 06.1.0
Sectoral scopes linked to the applied methodologies	01 (Energy Industries)
Estimated amount of annual average GHG emission reductions	904,733 tCO ₂ e/y

SECTION A. Description of project activity

A.1. Purpose and general description of project activity

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The purpose of this project is to improve the power generation efficiency which will aim to increase the generating capacity of the Pars 1 power plant, thereby helping to bridge the gap between supply and growing electrical energy demand of the country and the nearby gas production and processing facilities.

Pars 1 power plant which is located in Pars Special Economic Energy Zone (PSEEZ) is under operation in single cycle mode with 6 gas turbines each with a nominal electricity generation capacity of 160MW at ISO condition.

In single cycle operation, exhaust gases from gas turbines are vented to the atmosphere without any heat recovery while they contain high amount of thermal energy. By implementation of the project activity the heat from exhaust gases of these gas turbines will be recovered by installation of Heat Recovery Steam Generators (HRSGs). The produced steam will be consumed to produce electricity using steam turbines generators.

The project activity consists of design, procurement, construction and commissioning of a steam cycle including HRSGs, steam turbines, electrical generators, Air Cooled Condenser (ACC) system and also all related ancillaries. Total nominal capacity of project (steam cycle) is 480 MW.

The existing scenario prior to the start of the implementation of the project activity entails generation of power by the existing gas turbines in single cycle mode of operation.

The baseline scenario, as identified in section B.4 below, is the continuation of the current practice (to not implementing the project activity).

The projected annual electricity generation of the project is 6,912,481MWh/year. It is estimated that the project will reduce 904,733 tCO₂e annually, generating an expected total of 9,047,330 tCO₂e emission reduction during the 10-year crediting period.

The approved consolidated baseline and monitoring methodology ACM0007 version 06.1.0: "Conversion from single cycle to combined cycle power" is applicable for this project. The project falls in sectoral scope 1: energy industries (renewable/non-renewable sources).

The Environmental Impact Assessment (EIA) for the Project was performed in accordance with the Iranian Environmental Regulation and it was approved by the Department of Environment of Iran. The main conclusion of the EIA report was that the long-term positive socio-economic impacts of the project would outweigh relatively minor adverse impacts, which are mainly expected to take place during the construction phase of the project. The Project will result in significant reduction of air pollutants emission and will increase alternative energy supply resources durability. Successful implementation of this Project will encourage the intention to invest in energy efficiency improvement projects and thus the sustainable development of Iran.

The project satisfies the sustainable development guidelines provided by the Department of Environment of Iran (DOE) to help improve the quality of life, improve health level and reduce diseases.

The project will contribute to sustainable development in the following manner:

- GHGs mitigation through waste energy recovery and sustainable electricity generation; thus displacing the fossil fuel based electricity generation.
- Conservation of fossil energy resources of the country.
- Creation of new direct and indirect jobs during construction of the project as well as jobs for operation and maintenance of the project activity facilities. Meanwhile the Project will improve local education and technical training opportunities.

- Reduction of emissions of air pollutants generated by the fossil fuel fired power plants which can improve the working environment for workers and living environment for people in surrounding areas.
- Addition of 480MW to the national electricity generation capacity and consequently, more sustainable electricity supply to the nation and national industries.
- Technology transfer and promotion of environmentally safe and sound technologies in power sector of Iran

It is confirmed that the proposed CDM project activity is not a CPA that has been excluded from a registered CDM PoA as a result of erroneous inclusion of CPAs.

A.2. Location of project activity

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The project facilities will be installed in Pars 1 power plant. This power plant is located in north east of Asalouyeh, a city in Bushehr Province, Islamic Republic of Iran.

The geographical coordinates of the project site are:

27° 29' 11" N 52° 39' 33" E

Figures A-1 and A-2 show the location of the project:



Figure A-1: The geographical location of Bushehr Province in Iran



Figure A-2: Location of the Project

A.3. Technologies/measures

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Pars 1 power plant is under operation in single cycle mode with 6 gas turbines each with a nominal electricity generation capacity of 160MW at ISO condition.

In single cycle operation, exhaust gases from gas turbines are vented to the atmosphere without any heat recovery. By implementation of the project activity the heat from exhaust gases of existing gas turbines will be recovered by installation of Heat Recovery Steam Generators (HRSGs). The produced steam will be consumed to produce electricity using steam turbine generators.

The project activity consists of the design, procurement, construction and commissioning of required equipment to convert the power plant from single cycle to combined cycle.

The main equipment of steam cycle of the power plant are 6 HRSGs, 3 steam turbine generators with capacity of 160 MW each and an Air Cooled Condenser (ACC) system.

Total nominal capacity of project (steam cycle) is 480 MW.

Under the project activity the existing GTGs will be combined with 6 Heat Recovery Steam Generators (HRSG) and 3 Steam Turbine Generator (STG) to recover the heat from exhaust of gas turbines to generate additional electricity. Figure A-3 shows the schematic diagram of the project. The rated output power of the STG is 160MW which gives a total nominal capacity of 480MW (under ISO condition) for the project activity (steam cycle).

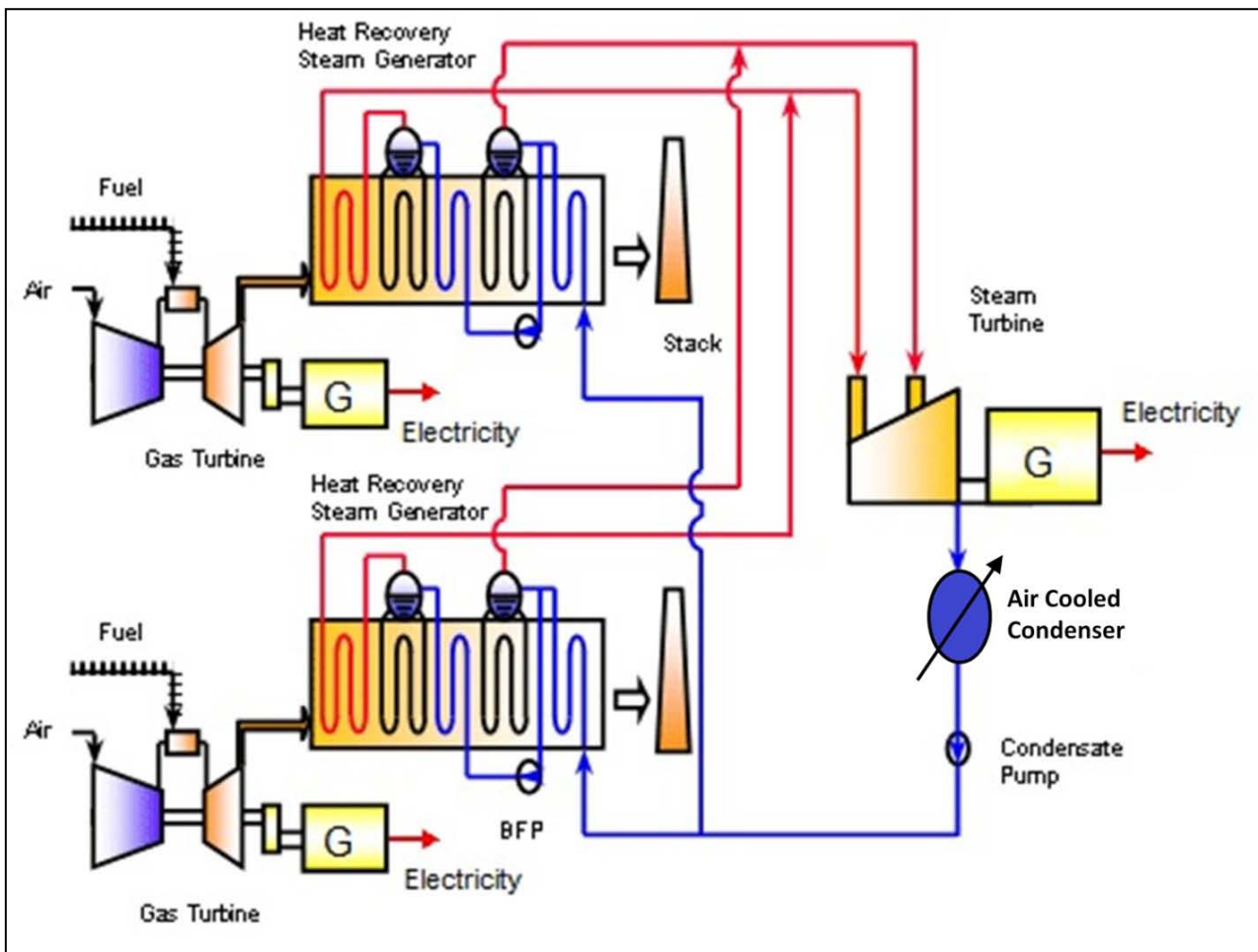


Figure A-3: Schematic Diagram of the Project

Natural gas flow meters will be used to measure the fuel consumption (natural gas), while electricity meters will be installed to measure the amount of generated electricity.

The general specification of the project and technical details of the main equipment are tabulated below:

Table 1: General specification of the Project (steam cycle)

Nominal capacity (ISO condition)	480MW
Annual electricity supply to grid	2,301GWh
Project Lifetime	20 yrs

Table 2: Specification of Existing Gas Turbine Generators

Manufacturer	MAPNA group under licence of ANSALDO
Model	V 94.2
Fuel	Natural gas
Frequency	50 Hz
Gross Nominal Power Output	157MW
Heat Rate	10459kJ/kWh
Exhaust Gas Temperature	541.3°C
Exhaust Mass Flow	513.52 kg/s

Table 3: Specification of Heat Recovery Steam Generators

Manufacturer	S&T Corporation for HRSG
Type	Horizontal
Main (HP) Steam Flow	248,220 kg/hr
Main (HP) Steam Pressure	93.8 kg/cm ²
Main (HP) Steam Temperature	525°C
LP steam flow	33,300 kg/hr
LP steam pressure	9.69 kg/cm ²
LP steam temperature	231.6°C

Table 4: Specification of Steam Turbine Generator

Manufacturer	Franco Tosi Meccanica and Ansaldo Energia
HP steam flow at Turbine inlet	137.9 kg/s
HP steam pressure at Turbine inlet	90 bar(a)
HP steam temperature at Turbine inlet	520°C
LP steam flow at Turbine inlet	18.5 kg/s
LP steam pressure at Turbine inlet	8.66 bar(a)
Turbine outlet pressure	0.34 bar
LP steam temperature at Turbine inlet	230°C
Power at generator terminals	147,758 kW
Heat rate	2,797.81 kcal/kWh
Rated speed	3,000 rpm

A.4. Parties and project participants

Parties involved	Project participants	Indicate if the Party involved wishes to be considered as project participant (Yes/No)
Iran (host)	National Iranian Oil Company	No
	Pars Oil and Gas Company	
	Farab Company	
	Mehr Renewable Energies Company	

A.5. Public funding of project activity

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The project has not received any type of public funding or public financial help.

A.6. History of project activity

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It is Confirmed that:

- The proposed CDM project activity is neither registered as a CDM project activity nor included as a component project activity (CPA) in a registered CDM programme of activities (PoA);

- b) The proposed CDM project activity is not a project activity that has been deregistered.

Also, it is declared that:

- a) The proposed CDM project activity was not a CPA that has been excluded from a registered CDM PoA;
- b) A registered CDM project activity or a CPA under a registered CDM PoA whose crediting period has or has not expired does not exist in the same geographical location as the proposed CDM project activity.

A.7. Debundling

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Not Applicable

SECTION B. Application of selected methodologies and standardized baselines

B.1. Reference to methodologies and standardized baselines

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The project uses the approved consolidated baseline and monitoring methodology ACM0007: "Conversion from single cycle to combined cycle power" (Version 06.1.0).

Refer to:

<https://cdm.unfccc.int/methodologies/DB/UVVSD3V6CADRJXKIKGUCFWRH3SRTKA>

This methodology also refers to the following tools:

Combined tool to identify the baseline scenario and demonstrate additionality, version 6.0

Refer to:

https://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-02-v6.0.pdf/history_view

Methodological tool: Common practice, version 03.1

Refer to:

http://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-24-v1.pdf/history_view

Tool to calculate project or leakage CO2 emissions from fossil fuel combustion, version 2

Refer to:

https://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-03-v2.pdf/history_view

Tool to calculate the emission factor for an electricity system, version 6.0

Refer to:

http://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-07-v5.0.pdf/history_view

Tool to determine the remaining lifetime of equipment, version 1

Refer to:

https://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-10-v1.pdf/history_view

B.2. Applicability of methodologies and standardized baselines

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Applicability conditions of the ACM0007 (Version 06.1.0) and compliance of Project activity with these conditions is explained in the table below:

Table B-1: Applicability conditions of ACM0007 (Version 06.1.0)

ACM0007 (Version 06.1.0) applicability conditions	Condition's compliance of the Project
<p>This methodology applies to project activities that convert one or several grid connected power units at one site from single-cycle to combined-cycle mode.</p>	<p>The project activity will convert the existing grid connected power units of Pars 1 power plant from single-cycle to combined-cycle mode.</p>
<p>This methodology applies if the project power unit(s) fulfil the following conditions:</p>	
<p>The unit(s) have an operational history of at least one year with no major retrofit, and at least one unit has an operational history of more than three years with no major retrofit. There is no major retrofit in these time periods;</p>	<p>All power units of Pars 1 power plant have an operational history of more than three years with no major retrofit.</p>
<p>In the case that a unit has less than three years operational history: all project power unit(s) were designed and commissioned for operation in single cycle mode only. This shall be demonstrated by the project participants by providing relevant documents, such as original process diagrams and schemes from the construction of the plant, licenses and/or by an on-site check by the DOE prior to the implementation of the project activity;</p>	<p>All power units of Pars 1 power plant have an operational history of more than three years.</p>
<p>During the most recent three years prior to the implementation of the project activity and during the crediting period the project power unit(s) use(d) only the following fuel types:</p> <ul style="list-style-type: none"> (a) Fossil fuels; and/or (b) Blends of fossil fuels and biofuels, where the biofuel is blended to the fossil fuel in a situation that is outside the control of the project participants (such as regulatory requirements to blend biodiesel with diesel or biogas with natural gas). <p>Note that this methodology does not allow crediting for an increase in the share of biofuels.</p>	<p>During the most recent three years prior to the implementation of the project activity the project power units used only fossil fuels. Also, the project units will only use fossil fuels during the crediting period.</p>
<p>The type(s) of fossil fuels used by the project power unit(s) during the crediting period were also used during the most recent three years prior to the implementation of the project activity, except, where applicable, any auxiliary fuel consumption (e.g. for start-ups) which shall not exceed 3% of the total fuel consumption in the unit(s) (measured on an energy basis).</p>	<p>Only natural gas has been used by the project power units during the most recent three years prior to the implementation of the project. This fossil fuel will be the main fuel of the power units during the crediting period, too.</p> <p>In case of utilization of any auxiliary fuel (e.g. for start-ups), the amount of consumption will not exceed 3% of the total fuel consumption in the units of energy basis.</p>

<p>this methodology is applicable under the condition that the project activity does not increase the lifetime of the existing gas turbine or engine during the crediting period, as determined using the “Tool to determine the remaining lifetime of equipment” (i.e. this methodology is applicable up to the end of the lifetime of existing gas turbine or engine, if shorter than crediting period).</p>	<p>The project activity will not increase the lifetime of the existing gas turbines during the crediting period as determined by “Tool to determine the remaining lifetime of equipment”.</p>
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B.3. Project boundary, sources and greenhouse gases (GHGs)

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	Source	GHG	Included?	Justification/Explanation
Baseline	Grid electricity generation	CO ₂	Yes	Main emission source
		CH ₄	No	Excluded for simplification. This is conservative
		N ₂ O	No	Excluded for simplification. This is conservative
	On-site fossil fuel consumption to operate the project power unit(s) in single cycle mode	CO ₂	Yes	An important emission source
		CH ₄	No	Excluded for simplification. This emission source is assumed to be very small
		N ₂ O	No	Excluded for simplification. This emission source is assumed to be very small
Project activity	On-site fossil fuel consumption to operate the project power unit(s) in combined cycle mode	CO ₂	Yes	An important emission source
		CH ₄	No	Excluded for simplification. This emission source is assumed to be very small
		N ₂ O	No	Excluded for simplification. This emission source is assumed to be very small
	On-site fossil fuel consumption to supplement the exhaust heat in operating the steam turbine	CO ₂	Yes	May be an important emission source
		CH ₄	No	Excluded for simplification. This emission source is assumed to be very small
		N ₂ O	No	Excluded for simplification. This emission source is assumed to be very small

B.4. Establishment and description of baseline scenario

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In line with the requirements of methodology ACM0007 version 06.1.0, the “Combined tool to identify the baseline scenario and demonstrate additionality” version 6.0 is used to determine the baseline.

Step 0: Demonstration whether the proposed project activity is the first-of-its-kind

The proposed project activity is not the first-of-its-kind; hence this step is not applied.

Outcome of Step 0:

The proposed project activity is not the first-of-its-kind.

Step 1: Identification of alternative scenarios

This Step serves to identify all alternative scenarios to the proposed CDM project activity(s) which can be the baseline scenario:

Step 1a: Define alternative scenarios to the proposed CDM project activity

According to the methodology ACM0007 version 06.1.0, in applying Step 1 of the “Combined tool to identify the baseline scenario and demonstrate additionality”, the following three alternatives should be considered:

- (a) Proposed project activity undertaken without being registered as a CDM project activity;
- (b) Continuation of the current practice (to not implementing the project activity);
- (c) If applicable the “proposed project activity undertaken without being registered as a CDM project activity” undertaken at a later point in time (e.g. due to existing regulations, end-of-life of existing equipment, financing aspects).

Alternative (c) is not applicable because there are no relevant expected regulatory changes or technical and operational changes such as achieving the end-of-life of existing equipment that could incentivise and/or facilitate the implementation of the proposed Project activity at a later point in time.

Outcome of Step 1a:

The following two alternatives are considered as plausible alternative scenarios to the project activity:

- (a) Proposed project activity undertaken without being registered as a CDM project activity;
- (b) Continuation of the current practice (to not implementing the project activity);

Step 1b: Consistency with mandatory applicable laws and regulations

The alternative scenario(s) shall be in compliance with all mandatory applicable legal and regulatory requirements.

There is not any mandatory applicable law and regulation in Iran which could exclude any of the defined alternative scenarios in step 1a. Therefore, both alternatives are consistent with applicable national laws and regulations of the host country.

Outcome of Step 1b:

List of alternative scenarios to the project activity that are in compliance with mandatory legislation and regulations is as follows:

- (a) Proposed project activity undertaken without being registered as a CDM project activity;
- (b) Continuation of the current practice (to not implementing the project activity);

Step 2: Barrier Analysis

This step serves to identify barriers and to assess which alternative scenarios are prevented by these barriers.

Step 2a: Identify barriers that would prevent the implementation of alternative scenarios

There is not any barrier that may prevent identified alternative scenarios to occur. Only insufficient financial return is a barrier for alternative (a) which will be analyzed in Step 3.

Outcome of Step 1b:

There is not any barrier that may prevent identified alternative scenarios to occur.

Step 2b: Eliminate alternative scenarios which are prevented by the identified barriers

As no barrier was identified in step 2a, no alternative is eliminated in this step.

Outcome of Step 2b:

List of alternative scenarios to the project activity that are not prevented by any barrier:

- (a) Proposed project activity undertaken without being registered as a CDM project activity;
- (b) Continuation of the current practice (to not implementing the project activity);

Outcome of Step 2:

As there is more than one alternative scenario that is not prevented by any barrier, and the alternative scenarios include the proposed project activity undertaken without being registered as a CDM project activity and also the proposed project activity is not the first-of-its-kind, it is directly proceed to Step 3 (investment analysis) according to the “Combined tool to identify the baseline scenario and demonstrate additionality” version 6.0.

Step 3: Investment analysis

The objective of Step 3 is to compare the economic or financial attractiveness of the alternative scenarios remaining after Step 2 by conducting an investment analysis.

This step has been described in section B.5 below.

Based on the result of investment analysis, alternative (b), continuation of the current practice (to not implementing the project activity), is the most financially attractive alternative scenario and considered as the baseline scenario.

Outcome of Step 3:

Alternative (b), continuation of the current practice (to not implementing the project activity), is the baseline scenario.

Step 4: Common practice analysis

The previous Steps shall be complemented with an analysis of the extent to which the proposed project type (e.g. technology or practice) has already diffused in the relevant sector and applicable geographical area. This test is a credibility check to demonstrate additionality and complements the barrier analysis (Step 2) and, where applicable, the investment analysis (Step 3).

In line with the requirements of the “Combined tool to identify the baseline scenario and demonstrate additionality” version 6.0, “Methodological tool: Common practice” version 03.1, is used for common practice analysis:

Step 1: calculate applicable capacity or output range as +/-50% of the total design capacity or output of the proposed project activity.

The nominal power generation capacity of the project activity is 480MW. Accordingly, the applicable capacity range for this project is 240MW~720MW.

Step 2: identify similar projects (both CDM and non-CDM) which fulfill all of the following conditions:

- (a) *The projects are located in the applicable geographical area;*

- (b) The projects apply the same measure as the proposed project activity;
- (c) The projects use the same energy source/fuel and feedstock as the proposed project activity, if a technology switch measure is implemented by the proposed project activity;
- (d) The plants in which the projects are implemented produce goods or services with comparable quality, properties and applications areas (e.g. clinker) as the proposed project plant;
- (e) The capacity or output of the projects is within the applicable capacity or output range calculated in Step 1;
- (f) The projects started commercial operation before the project design document (CDM-PDD) is published for global stakeholder consultation or before the start date of proposed project activity, whichever is earlier for the proposed project activity.

According to the latest published statistics by Ministry of Energy of Iran¹, among the power plants in operation in Iran before 31 May 2014 (start date of the project activity) those with steam cycle capacities between 240MW and 720MW which apply same measure (conversion of open cycle to combined cycle) are listed in bellow table.

Table B-3: list of similar projects for common practice analysis

Row	Power Plant	Nominal Capacity of steam cycle (MW)	Owner	Start of operation of steam cycle	Date of investment decision (if commissioned after 2005)
1	Gilan	446.4	Private	1997	N/A
2	Montazer Ghaem	300	Private	1999-2000	N/A
3	Shahid Rajaei	300	MOE	2001	N/A
4	Neishabour	300	Private	2002-2003	N/A
5	Fars	294.9	Private	2002	N/A
6	Neka	275	MOE	2006	11/11/2002
7	Yazd	318	MOE	2008-2009	11/11/2002
8	Kazeroun	480	Private	2006-2007	11/11/2002
9	Kerman	640	MOE	2007-2008	11/11/2002
10	Sanandaj	320	Private	2011-2012	25/07/2007
11	Parehsar	320	Private	2013	07/12/2008

Step 3: within the projects identified in Step 2, identify those that are neither registered CDM project activities, project activities submitted for registration, nor project activities undergoing validation. Note their number N_{all} .

Within the power plants listed in table B-3, Sanandaj and Parehsar are registered CDM projects; hence:

11 projects of total, 2 projects are CDM projects, thus $N_{all} = 9$.

¹ <http://www2.tavanir.org.ir/info/stat92/sanat/html/xls/13-1.xls> ,
<http://www2.tavanir.org.ir/info/stat92/sanat/html/xls/13-2.xls>

Step 4: within similar projects identified in Step 3, identify those that apply technologies that are different to the technology applied in the proposed project activity. Note their number N_{diff} .

Technology difference for identified power plants is:

- Investment climate at the date of investment decision, eg. Legal regulations: project start prior to the creation of the power pool in Iran in 2005²

Before the creation of the power pool in Iran there was not an electricity price paid to the power plants for electricity generation and investment in power generation were centrally decided based on non-market mechanisms. As the investment decision of all listed projects (except 2 registered CDM projects) have been made before 2005 (in a different investment climate than proposed project); hence, all 9 power plants identified in step 3 above, are different than the proposed project activity. Thus $N_{diff} = 9$.

Step 5: calculate factor $F=1-N_{diff}/N_{all}$ representing the share of similar projects (penetration rate of the measure/technology) using a measure/technology similar to the measure/technology used in the proposed project activity that deliver the same output or capacity as the proposed project activity.

$$F = 1 - 9 / 9 = 1 - 1 = 0$$

The proposed project activity is a “common practice” within a sector in the applicable geographical area if the factor F is greater than 0.2 and $N_{all}-N_{diff}$ is greater than 3.

While $F = 0$ and $N_{all} - N_{diff} = 9 - 9 = 0$, thus the proposed project activity is **not** a common practice in the power sector of Iran.

B.5. Demonstration of additionality

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As mentioned in section B.4 above, the “Combined tool to identify the baseline scenario and demonstrate additionality” version 6.0 is used to identify the baseline and demonstrate additionality. Step 3 of this tool is “investment analysis” for comparing the alternative scenarios.

The benchmark analysis is used for this investment analysis since CDM is not the only revenue for the Project; it generates revenue from electricity generation. This choice is consistent with “Methodological tool: Investment analysis (Version 06)”.

The pre-tax project internal rate of return (IRR) is considered as an appropriate financial indicator for the investment analysis of the Project. The likelihood of the development of this Project, rather than continuation of the current practice (the baseline) will be determined by comparing the IRR of the Project without CDM financing to a suitable benchmark. As per the “Methodological tool: Investment analysis (Version 06)”, benchmark supplied by relevant national authorities are appropriate.

According to the expected rate of return on facilities published by Sepah Bank³, the rate of return of the projects shall be at least 18%. While the expected rate of return in the FSR of the project is considered to be 25%, for the sake of conservativeness, the rate of 18% is considered the benchmark in the following investment analysis.

The following parameters have been used to calculate the IRR of the project activity:

Table B-3: Financial Parameters for investment analysis

Parameter	Unit	Value
Annual electricity generation	MWh/y	2,300,559

² Power Sector Note of Iran, World Bank, 2007, page 40

³ <http://www.banksepah.ir/default-1360.aspx?init>

Electricity tariff	Rial/kWh	260	
Total annual revenue	M Rials	598,145	
Total investment	M Rials	11,146,060	
Annual O&M cost	Fixed O&M cost	M Rials	19,795
	Variable O&M cost	M Rials	4,137
	Total annual O&M cost	M Rials	23,932
Construction period	year	4	
Project lifetime	year	20	

The IRR of the Project with and without revenue from CDM are shown in the table B-4 below.

Table B-4: IRR of the Project with and without CDM

	IRR
Without revenue from CDM	0.25%
With revenue from CDM	5.85%

As shown above, the IRR of the Project without inclusion of revenue from CDM is 0.25%, which is lower than the benchmark IRR of 18%, which indicates that the Project is not financially attractive without CDM revenues. Therefore, the Project was not financially attractive in the absence of CER revenue.

In order to assess whether the conclusion regarding the financial attractiveness is robust to reasonable variations in the critical assumptions, sensitivity analysis is undertaken for the proposed project activity.

According to the “*Methodological tool: Investment analysis (Version 06)*”, only variables, including the construction investment, that constitute more than 20% of either total project costs or total project revenues should be subjected to reasonable variation. For the project activity, revenue stream (electricity tariff), annual running cost, the total investment and annual electricity production are selected for variables subject to the sensitivity analysis based on their quantitative materiality following the tool.

The table and figure below show variation of IRR when the selected four critical variables are changed in the range of –10% and +10% (the range is equivalent to the least cover range stipulated in “*Methodological tool: Investment analysis (Version 06)*”).

Table B-5: Results of the sensitivity analysis

	-10.0%	0.0	10.0%
Benchmark	18.0%	18.0%	18.0%
Electricity tariff	-0.66	0.25	1.10
Annual running cost	0.29	0.25	0.22
Total investment	1.15	0.25	-0.54
Annual Electricity production	-1.96	0.25	1.09

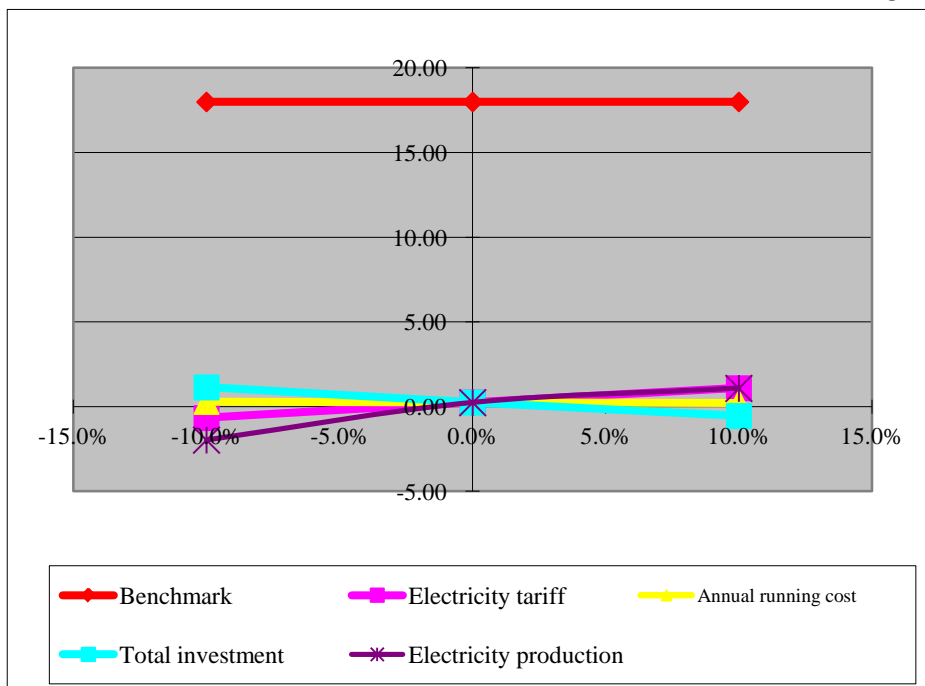


Figure B-2: Results of the sensitivity analysis of the Project

As shown above, in none of the above cases, the IRR meets the benchmark IRR of 18%, thus the Project is not financially attractive even if the major parameters (Electricity tariff, capital cost, annual running cost or annual electricity production) varies in the reasonable range of ±10%. Therefore, based on the above analysis, it is proved that the Project is not financially attractive without CDM revenues and the conclusion regarding the financial/economic attractiveness is robust. In addition, the magnitude of change required to make the project scenario financially attractive is shown in the following table B-6.

Table B-6: Results of the critical analysis

Parameters	Rate of change	IRR
Electricity tariff	358.0%	18.00%
Annual running cost	-100.0%	0.6%
Capital cost	-78.9%	18.04%
Annual electricity production	361.0%	18.00%

As shown in the above table, the magnitude of change required to make the project scenario economically attractive is 358% for electricity tariff, -78.9% for capital cost, and 361% for annual electricity production, respectively. These magnitudes of the change are very unlikely to occur because;

- ❖ Electricity tariff: The annual average increasing rate of electricity tariff has been less than 24% in last seven years. This means 358% increase of electricity tariff, which is necessary to make the Project more economically attractive than the alternative, is unrealistic.
- ❖ Based on the EPC contract, the real cost of the project is higher than the estimated value in the FSR. Hence, reduction of capital cost by 78.9% from the FSR is very unlikely to occur.
- ❖ Annual running cost: Annual running cost is composed of the consumables, spare parts cost and labour cost and during the operation period of the Project, the running cost has to be covered; thus, it is impossible that the running cost decreases 100%; and even if the running cost is zero, the IRR of the Project is still below the benchmark.

- ❖ Annual electricity production: the amount of electricity production considered in the FSR is based on the project capacity and the project power generation capacity will not be changed in the future. Thus, the 361% increase in annual electricity production is unrealistic.

Other steps of “Combined tool to identify the baseline scenario and demonstrate additionality” version 6.0 has been provided in section B.4 above.

As a conclusion of sections B.4 and B.5, Alternative (b), continuation of the current practice (to not implementing the project activity) is the baseline scenario and the proposed project activity is additional.

B.6. Estimation of emission reductions

B.6.1. Explanation of methodological choices

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Emission reductions are determined as follows:

$$ER_y = BE_y - PE_y - LE_y \quad (1)$$

Where:

ER_y = Emissions reductions in year y (tCO₂/y)

BE_y = Baseline emissions in year y (tCO₂/y)

PE_y = Project emissions in year y (tCO₂/y)

LE_y = Leakage emissions in year y (tCO₂/y)

Project emissions

As per methodology ACM0007 version 06.1.0, project emissions (PE_y) should be determined using the “Tool to calculate project or leakage CO₂ emissions from fossil fuel combustion”. Latest version of this tool (version 02) will be used to calculate the project emissions of this project activity as follows:

$$PE_y = PE_{FC,j,y} = \sum_i FC_{i,j,y} \times COEF_{i,y} \quad (2)$$

Where:

PE_{FC,j,y} = CO₂ emissions from fossil fuel combustion in process j during the year y (tCO₂/y)

FC_{i,j,y} = Quantity of fuel type i combusted in process j during the year y (mass or volume unit/y)

COEF_{i,y} = CO₂ emission coefficient of fuel type i in year y (tCO₂/mass or volume unit)

i = Fuel types combusted in process j during the year y

According to the methodology ACM0007 version 06.1.0, “j” corresponds to the combustion of fossil fuels to operate the project power unit(s) and to supplement the exhaust heat in operating the steam turbine.

Option A of “Tool to calculate project or leakage CO₂ emissions from fossil fuel combustion” version 02 will preferably be used to calculate the CO₂ emission coefficient (COEF_{i,y}) in case of availability of the required data:

Option A: The CO₂ emission coefficient COEF_{i,y} is calculated based on the chemical composition of the fossil fuel type i, using the following approach:

If $FC_{i,j,y}$ is measured in a mass unit:

$$COEF_{i,y} = w_{C,i,y} \times 44/12 \quad (3)$$

If $FC_{i,j,y}$ is measured in a volume unit:

$$COEF_{i,y} = w_{C,i,y} \times \rho_{i,y} \times 44/12 \quad (4)$$

Where:

$w_{C,i,y}$ = weighted average mass fraction of carbon in fuel type i in year y (tC/mass unit of the fuel)

$\rho_{i,y}$ = weighted average density of fuel type i in year y (mass unit/volume unit of the fuel)

In case of unavailability of the data required for option A, option B will be used to calculate the CO₂ emission coefficient ($COEF_{i,y}$):

Option B: The CO₂ emission coefficient $COEF_{i,y}$ is calculated based on net calorific value and CO₂ emission factor of the fuel type i , as follows:

$$COEF_{i,y} = NCV_{i,y} \times EF_{CO_2,i,y} \quad (5)$$

Where:

$NCV_{i,y}$ = weighted average net calorific value of the fuel type i in year y (GJ/mass or volume unit)

$EF_{CO_2,i,y}$ = weighted average CO₂ emission factor of fuel type i in year y (tCO₂/GJ)

Baseline emissions

The baseline emissions for year y (BE_y) are calculated as follows:

Step A: Determination of the baseline emissions for different scenarios of project electricity generation

Case (a) The quantity of electricity generated in the project power unit(s), adjusted for changes to efficiency, ($EG_{PJ,adj,y}$) is lower than or equal to the historic average annual generation level ($EG_{BL,AVR}$). Baseline emissions are calculated as:

$$BE_y = EG_{PJ,adj,y} \cdot EF_{CO_2,BL} \quad (6)$$

Case (b) The quantity of electricity generated in the project power unit(s), adjusted for changes to efficiency, ($EG_{PJ,adj,y}$) exceeds the historic average annual generation level ($EG_{BL,AVR}$), but is lower than or equal to the maximum annual quantity of electricity that the project power unit(s) could have produced prior to the implementation of the project activity (EG_{MAX}). Baseline emissions are calculated as:

$$BE_y = EG_{BL,AVR} \cdot EF_{CO_2,BL,y} + (EG_{PJ,adj,y} - EG_{BL,AVR}) \cdot \min(EF_{CO_2,BL}; EF_{grid,y}) \quad (7)$$

Case (c) The quantity of electricity generated in the project power unit(s), adjusted for changes to efficiency, ($EG_{PJ,adj,y}$) exceeds the maximum annual quantity of electricity that the project power unit(s) could have produced prior to the implementation of the project activity (EG_{MAX}). Baseline emissions are calculated as:

$$BE_y = EG_{BL,AVR} \cdot EF_{CO_2,BL,y} + (EG_{MAX} - EG_{BL,AVR}) \cdot \min(EF_{CO_2,BL,y}; EF_{grid,y}) + (EG_{PJ,adj,y} - EG_{MAX}) \cdot EF_{grid,y} \tag{8}$$

Where:

- BE_y = Baseline emissions in year y (tCO₂/yr)
- EG_{PJ,adj,y} = Quantity of electricity supplied by all project power units to the electricity grid in year y, adjusted for changes to efficiency (MWh/yr)
- EG_{BL,AVR} = Average annual quantity of electricity supplied by all project power units to the electricity grid during the defined operational history (MWh/yr)
- EG_{MAX} = Maximum annual quantity of electricity that could be generated by all project power units in the baseline scenario (MWh/yr)
- EF_{CO₂,BL} = Baseline emission factor of all project power units operated in single cycle mode (tCO₂/MWh)
- EF_{grid,y} = Emission factor of the electricity grid to which the project power unit is connected (tCO₂/MWh)

As per methodology ACM0007 version 06.1.0, the maximum annual quantity of electricity that could be generated by the project power unit(s) in the baseline scenario (EG_{MAX}) is calculated as:

$$EG_{MAX} = CAP_{max} \cdot T_{max} \tag{9}$$

Where:

- EG_{MAX} = Maximum annual quantity of electricity that could be generated by all project power units in the baseline scenario (MWh/yr)
- CAP_{max} = Maximum gross power generation capacity of the project power unit(s) prior to the implementation of the project activity (MW)
- T_{MAX} = Maximum amount of time during a year in which the project power unit(s) could have operated at full power generation capacity prior to the implementation of the project activity (hours/yr)

All project power units have three years operational history, and there was no major retrofit during this period in any of the units. Hence, the maximum annual amount of time that the project power unit(s) could have operated at full load prior to the validation of the project activity is calculated according to the equation below:

$$T_{MAX} = 8,760 - \frac{\sum_{x=1}^3 HMR_x}{3} \tag{10}$$

Where:

- T_{MAX} = Maximum amount of time during a year in which the project power unit(s) could have operated at full power generation capacity prior to the implementation of the project activity (hours/yr)
- HMR_x = Average number of hours during which the plant did not operate due to maintenance or repair in year x (hours/yr)
- x = Each year during the three years operational history

The average annual amount of electricity supplied to the electricity grid by the project power unit(s) in the three years historical period is calculated according to equation 11. This calculation should be based on data from only those units that have at least a three years operational history and no major retrofit during this period.

$$EG_{BL,AVR} = \frac{\sum_{x=1}^3 EG_x}{3} \quad (11)$$

Where:

$EG_{BL,AVR}$ = Average annual quantity of electricity supplied by all project power units to the electricity grid during the three year operational history (MWh/yr)

EG_x = Quantity of electricity supplied by the project power unit(s) with three years operational history and no retrofit in this period, to the electricity grid in year x (MWh/yr)

x = Each year of the three years operational history

According to the methodology ACM0007 version 06.1.0, the total amount of electricity supplied to the electricity grid by all project power units in year y of the crediting period has to be adjusted for the calculation of baseline emissions so that future energy efficiency improvement measures (e.g. measures that may be implemented after the project activity) shall not result in emissions reductions. Therefore, the total amount of electricity supplied to the grid ($EG_{PJ,y}$) shall be conservatively adjusted by applying a discount factor based on the minimum of the monitored efficiencies after the implementation of the project activity, as described in the equations below:

$$EG_{PJ,adj,y} = EG_{PJ,y} \cdot \frac{\eta_{PJ,min,y}}{\eta_{PJ,y}} \quad (12)$$

with

$$\eta_{PJ,min,y} = \min(\eta_{PJ,1}, \dots, \eta_{PJ,y}) \quad (13)$$

Where:

$EG_{PJ,adj,y}$ = Quantity of electricity supplied by all project power units to the electricity grid in year y, adjusted for changes to project power plant efficiency (MWh/yr)

$EG_{PJ,y}$ = Total amount of electricity supplied to the electricity grid by the project power units in year y (MWh/yr)

$\eta_{PJ,min,y}$ = Minimum of the yearly average energy efficiency of the project power unit(s) monitored during the previous years (1 to y) after the implementation of the project activity for year y

$\eta_{PJ,1} \dots \eta_{PJ,y}$ = Average energy efficiency of the project power unit(s) in years 1 to y of the crediting period (refer to $\eta_{PJ,y}$ in the monitoring tables)

Step B: Estimating the emissions factor for electricity generated in single cycle mode in the baseline ($EF_{CO2,BL}$)

All project power units have a three years operational history and there was no major retrofit in these units during this period. Hence, the baseline CO₂ emissions factor for the project power units operated in single cycle mode ($EF_{CO2,BL}$) is determined based on the historical performance of the units and calculated according to equation below:

$$EF_{CO_2,BL} = \frac{\sum_{x=1}^3 \sum_i FC_{i,x} \cdot NCV_{i,x}}{\sum_{x=1}^3 EG_x} \times EF_{CO_2,min} \quad (14)$$

Where:

$EF_{CO_2,BL}$ = CO₂ emission factor for electricity generated in single cycle mode in the baseline (tCO₂/MWh)

$FC_{i,x}$ = Quantity of fuel type i used by the project power unit(s) in year x (mass or volume unit/yr)

$NCV_{i,x}$ = Net calorific value of the fuel type i used by the project power unit(s) in year x (GJ/mass or volume unit)

$EF_{CO_2,min}$ = CO₂ emission factor of the least carbon intensive fuel type used by the project power unit(s) during the three years operational history (tCO₂/GJ)

EG_x = Quantity of electricity supplied by the project power unit(s) with three years operational history and no retrofit in this period, to the electricity grid in year x (MWh/yr)

x = Each year of the three years operational history

Step C: Determine the emissions factor for the grid electricity system ($EF_{grid,y}$)

According to the methodology ACM0007 version 06.1.0, the baseline emission factor for the grid ($EF_{grid,y}$) should be calculated as a combined margin emission factor, using the “Tool to calculate the emission factor for an electricity system”.

The combined margin emission factor is calculated in accordance with six steps provided by the “tool to calculate the emission factor for an electricity system” version 4.0:

STEP 1. Identify the relevant electricity systems;

STEP 2. Choose whether to include off-grid power plants in the project electricity system (optional);

STEP 3. Select a method to determine the operating margin (OM);

STEP 4. Calculate the operating margin emission factor according to the selected method;

STEP 5. Calculate the build margin (BM) emission factor;

STEP 6. Calculate the combined margin (CM) emission factor.

Step 1. Identify the relevant electricity systems.

The produced electricity of the project activity will displace electricity from national grid of Iran (NGI). Hence, the spatial extent of the project boundary is the NGI.

The distribution network of the NGI has interconnections with electricity systems of Armenia, Azerbaijan, Turkey, Nakhichevan, Pakistan, Afghanistan, Turkmenistan and Iraq. These connections are operating both for import and export of electricity. In recent 3 years (2011-2014), the electricity has been imported only from Armenia, Azerbaijan, Nakhichevan and Turkmenistan, while electricity has been exported to all of the connected countries, except Azerbaijan.

According to requirement of the *tool to calculate the emission factor for an electricity system*, imports of electricity from connected electricity systems have been taken into account in determining the operating margin emission factor, using the procedure described in the Tool:

For the purpose of determining the operating margin emission factor, use one of the following options to determine the CO₂ emission factor(s) for net electricity imports from a connected electricity system:

(a) 0 t CO₂/MWh; or

- (b) The simple operating margin emission rate of the exporting grid, determined as described in Step 4 section 6.4.1, if the conditions for this method, as described in Step 3 below, apply to the exporting grid; or
- (c) The simple adjusted operating margin emission rate of the exporting grid, determined as described in Step 4 section 6.4.2 below; or
- (d) The weighted average operating margin (OM) emission rate of the exporting grid, determined as described in Step 4 section 6.4.4 below.

For imports from connected electricity systems located in Annex-I country (ies), the emission factor is 0 tons CO₂ per MWh.

The simple adjusted operating margin (option c) and simple operating margin (option b) emission factors have been used for electricity imports from Armenia and Azerbaijan, respectively. These emission factors have been obtained from registered CDM projects of these countries. For electricity imports from Nakhichevan and Turkmenistan, the most conservative emission factor (0tCO₂/MWh) has been used, because of the lack of required data. The details of the calculations are provided in ER calculation spreadsheet.

Also electricity exports have not been subtracted from electricity generation data used for calculating and monitoring the electricity emission factors, according to the requirement of the Tool.

Step 2. Choose whether to include off-grid power plants in the project electricity system (optional).

Option I of step 2 has been selected to calculate the operating margin and build margin emission factors. Therefore, only grid power plants are included in the calculation.

Step 3. Select a method to determine the operating margin (OM).

The calculation of the operating margin emission factor (EF_{grid,OM,y}) is based on one of the following methods:

- (a) Simple OM; or
- (b) Simple adjusted OM; or
- (c) Dispatch data analysis OM; or
- (d) Average OM

The simple OM method (option a) can only be used if low-cost/must-run resources constitute less than 50% of total grid generation in: 1) average of the five most recent years, or 2) based on long-term averages for hydroelectricity production.

As shown in the table below, low-cost/most-run resources constitute less than 50% of total grid generation in the five most recent years. Hence, the simple OM method is applicable in calculation of operating margin emission factor.

Table 9: proportions of low cost/must run resources in total grid electricity generation

Title	1388 (3/21/2009-3/20/2010)	1389 (3/21/2010-3/20/2011)	1390 (3/21/2011-3/20/2012)	1391 (3/21/2012-3/20/2013)	1392 (3/21/2013-3/20/2014)
Total generation (GWh) from low-cost/must-run resources (hydro)	7,146	9,446	11,984	12,377	14,391
Total generation (GWh) from low-cost/must-run resources (others)	228	211	574	2,067	4,767
Total generation (GWh) from low-cost/must-run resources (total)	7,374	9,657	12,558	14,444	19,158
Total grid generation (GWh)	212,335	224,320	231,041	245,303	252,850
Ratio of total generation of low-cost/must-run resources to the total grid generation	3.47%	4.31%	5.44%	5.89%	7.58%

The *ex-ante* option with using the data vintage as 3-year generation-weighted average based on the most recent data is chosen for calculation of simple OM emission factor.

Step 4. Calculate the operating margin emission factor according to the selected method

The simple OM emission factor ($EF_{grid,OMsimple,y}$) is calculated as the generation-weighted average CO₂ emissions per unit net electricity generation (tCO₂/MWh) of all generating power plants serving the system, not including low-cost/must-run power plants/units.

The simple OM may be calculated by one of the following two options:

Option A: Based on the net electricity generation and a CO₂ emission factor of each power unit; or

Option B: Based on the total net electricity generation of all power plants serving the system and the fuel types and total fuel consumption of the project electricity system.

Because enough data is available for NGI, thus option A is used.

Option A - Calculation based on average efficiency and electricity generation of each plant

Under this option, the simple OM emission factor is calculated based on the net electricity generation of each power unit and an emission factor for each power unit, as follows:

$$EF_{grid,OMsimple,y} = \frac{\sum_m EG_{m,y} \cdot EF_{EL,m,y}}{\sum_m EG_{m,y}} \quad (15)$$

Where:

$EF_{grid,OMsimple,y}$ = Simple operating margin CO₂ emission factor in year y (tCO₂/MWh)

$EG_{m,y}$ = Net quantity of electricity generated and delivered to the grid by power unit m in year y (MWh)

$EF_{EL,m,y}$ = CO₂ emission factor of power unit m in year y (tCO₂/MWh)

m = All power units serving the grid in year y except low-cost / must-run power units

y = The relevant year as per the data vintage chosen in Step 3

Determination of $EF_{EL,m,y}$

Option A1. If for a power unit m data on fuel consumption and electricity generation is available, the emission factor ($EF_{EL,m,y}$) should be determined as follows:

$$EF_{EL,m,y} = \frac{\sum_i FC_{i,m,y} \cdot NCV_{i,y} \cdot EF_{CO2,i,y}}{EG_{m,y}} \quad (16)$$

Where:

$EF_{EL,m,y}$ = CO₂ emission factor of power unit m in year y (tCO₂/MWh)

$FC_{i,m,y}$ = Amount of fossil fuel type i consumed by power unit m in year y (Mass or volume unit)

$NCV_{i,y}$ = Net calorific value (energy content) of fossil fuel type i in year y (GJ/mass or volume unit)

$EF_{CO2,i,y}$ = CO₂ emission factor of fossil fuel type i in year y (tCO₂/GJ)

$EG_{m,y}$ = Net quantity of electricity generated and delivered to the grid by power unit m

in year y (MWh)

- m = All power units serving the grid in year y except low-cost/must-run power units
 i = All fossil fuel types combusted in power unit m in year y
 y = The relevant year as per the data vintage chosen in Step 3

Option A2. If for a power unit m only data on electricity generation and the fuel types used is available, the emission factor should be determined based on the CO₂ emission factor of the fuel type used and the efficiency of the power unit, as follows:

$$EF_{EL,m,y} = \frac{EF_{CO_2,m,i,y} \times 3.6}{\eta_{m,y}} \quad (17)$$

Where:

- $EF_{EL,m,y}$ = CO₂ emission factor of power unit m in year y (tCO₂/MWh)
 $EF_{CO_2,m,i,y}$ = Average CO₂ emission factor of fuel type i used in power unit m in year y (tCO₂/GJ)
 $\eta_{m,y}$ = Average net energy conversion efficiency of power unit m in year y (ratio)
 m = All power units serving the grid in year y except low-cost/must-run power units
 y = The relevant year as per the data vintage chosen in Step 3

Where several fuel types are used in the power unit, use the fuel type with the lowest CO₂ emission factor for $EF_{CO_2,m,i,y}$.

Whereas the data on fuel consumption and electricity generation is available for every power plants of NGI, option A1 is used for determination of $EF_{EL,m,y}$, except in one power plant (Mes Sarcheshmeh-steam), which option A2 is used for calculation of $EF_{EL,m,y}$ because only data on electricity generation and the fuel type used is available for this power plant.

Determination of $EG_{m,y}$

The data on net electricity generation and types and amount of fuels consumed in each power plant and also data on the net caloric values of the fuels are obtained from the National Statistics of Iran Power Industry from 2011 to 2014 (latest published data).

The emission factors of the fuels are obtained from national documents provided by Ministry of Energy of Iran (Electric Power Industry in Iran, and Iran and World Energy Facts and Figures).

The details of the calculations are provided in ER calculation spreadsheet.

Step 5. Calculate the build margin (BM) emission factor.

In terms of vintage of data, project participants chooses option 1 to calculate the BM emission factor ($EF_{grid,BM,y}$) of the national grid. The Option 1 is described as follow:

Option 1: For the first crediting period, calculate the build margin emission factor *ex ante* based on the most recent information available on units already built for sample group m at the time of CDM-PDD submission to the DOE for validation. For the second crediting period, the build margin emission factor should be updated based on the most recent information available on units already built at the time of submission of the request for renewal of the crediting period to the DOE. For the third crediting period, the build margin emission factor calculated for the second crediting period should be used. This option does not require monitoring the emission factor during the crediting period.

The sample group of power units m used to calculate the build margin should be determined as per the following procedure, consistent with the data vintage selected above:

- (a) Identify the set of five power units, excluding power units registered as CDM project activities, that started to supply electricity to the grid most recently ($SET_{5\text{-units}}$) and determine their annual electricity generation ($AEG_{SET\text{-}5\text{-units}}$, in MWh);
- (b) Determine the annual electricity generation of the project electricity system, excluding power units registered as CDM project activities (AEG_{total} , in MWh). Identify the set of power units, excluding power units registered as CDM project activities, that started to supply electricity to the grid most recently and that comprise 20% of AEG_{total} (if 20% falls on part of the generation of a unit, the generation of that unit is fully included in the calculation), $SET_{\geq 20\%}$ and determine their annual electricity generation ($AEG_{SET\geq 20\%}$, in MWh);
- (c) From $SET_{5\text{-units}}$ and $SET_{\geq 20\%}$ select the set of power units that comprises the larger annual electricity generation (SET_{sample});

Identify the date when the power units in SET_{sample} started to supply electricity to the grid. If none of the power units in SET_{sample} started to supply electricity to the grid more than 10 years ago, then use SET_{sample} to calculate the build margin. Ignore steps (d), (e) and (f).

Since the $AEG_{SET\geq 20\%}$ is larger than $AEG_{SET\text{-}5\text{-units}}$ (The details of the calculations are provided in ER calculation spreadsheet), $SET_{\geq 20\%}$ was selected as SET_{sample} .

Based on the most recent information available at the time of CDM-PDD submission to the DOE for validation, the oldest power unit in SET_{sample} has started to supply electricity to the grid since 2007. As none of the power units in SET_{sample} started to supply electricity to the grid more than 10 years ago, SET_{sample} was used to calculate the build margin and steps (d), (e) and (f) were ignored.

The build margin emission factor is the generation-weighted average emission factor (tCO_2/MWh) of all power units m during the most recent year y for which power generation data is available, calculated as follow:

$$EF_{grid,BM,y} = \frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}} \quad (18)$$

Where:

$EF_{grid,BM,y}$ = Build margin CO_2 emission factor in year y (tCO_2/MWh)

$EG_{m,y}$ = Net quantity of electricity generated and delivered to the grid by power unit m in year y (MWh)

$EF_{EL,m,y}$ = CO_2 emission factor of power unit m in year y (tCO_2/MWh)

m = Power units included in the build margin

y = Most recent historical year for which power generation data is available

The tool further states that "The CO_2 emission factor of each power unit m ($EF_{EL,m,y}$) should be determined as per the guidance in Step 4 (a) for the simple OM, using options A1, A2 or A3, using for y the most recent historical year for which power generation data is available, and using for m the power units included in the build margin."

The details of the calculations are provided in ER calculation spreadsheet.

Step 6. Calculate the combined margin (CM) emissions factor.

According to the tool, the combined margin emission factor shall be calculated by weighted average method using a 50/50 OM/BM weight, as follows:

$$EF_{grid,CM,y} = EF_{grid,OM,y} \times W_{OM} + EF_{grid,BM,y} \times W_{BM} \quad (19)$$

Where:

- $EF_{grid,BM,y}$ = Build margin CO₂ emission factor in year y (tCO₂/MWh)
- $EF_{grid,OM,y}$ = Operating margin CO₂ emission factor in year y (tCO₂/MWh)
- W_{OM} = Weighting of operating margin emissions factor (%)
- W_{BM} = Weighting of build margin emissions factor (%)

Leakage emissions

According to the methodology ACM0007 version 06.1.0, the main emissions potentially giving rise to leakage in the context of the proposed projects are:

- (i) Emissions associated with the situation that exhaust heat was already recovered prior to the implementation of the project activity, in which case the diversion of this heat to the project power unit(s) may increase emissions elsewhere; and
- (ii) Emissions associated with extraction, production, transportation, distribution and processing of an increased quantity of fossil fuels consumed by the project activity ($LE_{upstream,y}$).

Leakage emissions are calculated as follows:

$$LE_y = LE_{upstream,y} + LE_{HR,y} \quad (20)$$

Where:

- LE_y = Leakage emissions in year y (tCO₂e/yr)
- $LE_{upstream,y}$ = Leakage emissions associated with the upstream emissions of an increase in fossil fuel use in the project activity in year y (tCO₂e/yr)
- $LE_{HR,y}$ = Leakage emissions due to a decrease in the amount of heat recovered from exhaust heat for purposes other than power generation in the project, compared to the most recent year prior to the implementation of the project activity, in year y (tCO₂e/yr)

Determination of $LE_{HR,y}$

Exhaust heat of gas turbines was not recovered prior to the implementation of the project activity. Hence, emissions from this leakage source are equal to zero ($LE_{HR,y}=0$).

Determination of $LE_{upstream,y}$

In cases where the fuel consumption in the project activity is lower than the historical fuel consumption in the three historical years x , leakage emissions from this source are equal to zero. Otherwise, leakage emissions associated with the upstream emissions from an increase in fossil fuel use in the project activity shall be considered. The leakage emissions are calculated as follows:

$$LE_{upstream,y} = \max \left[0, \left(\sum_i (FC_{i,y} \cdot NCV_{i,y} \cdot EF_{i,upstream,CH4}) \cdot GWP_{CH4} + LE_{LNG,CO2,y} \right) \cdot \left(1 - \frac{\frac{1}{3} \cdot \sum_{x=1}^3 \sum_i FC_{i,x} \cdot NCV_{i,x}}{\sum_i FC_{i,y} \cdot NCV_{i,y}} \right) \right]$$

(21)

Where:

- $LE_{upstream,y}$ = Leakage emissions associated with the upstream emissions from an increase in fossil fuel use in the project activity in the year y (tCO₂e/yr)
- $FC_{i,y}$ = Quantity of fuel type i used by the project power unit(s) in year y (mass or volume unit/yr)
- $NCV_{i,y}$ = Average net calorific value of the fuel type i used by the project power unit(s) in year y (GJ/mass or volume unit)
- $EF_{i,upstream,CH_4}$ = Emission factor for upstream fugitive methane emissions from production, transportation, distribution of fossil fuel i used by the project power unit(s) in year y (tCH₄/GJ)
- GWP_{CH_4} = Global warming potential of methane valid for the relevant commitment period (tCO₂e/tCH₄)
- $LE_{LNG,CO_2,y}$ = Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system in year y (tCO₂e/yr)
- $FC_{i,x}$ = Quantity of fuel type i used by the project power unit(s) in year x (mass or volume unit/yr)
- $NCV_{i,x}$ = Net calorific value of fuel type i used by the project power unit(s) in year x (GJ/mass or volume unit)
- x = Each year of the three years operational history

The power plant directly uses natural gas and there is not any conversion of LNG to natural gas in the project activity. Therefore, leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system are equal to zero ($LE_{LNG,CO_2,y}=0$).

B.6.2. Data and parameters fixed ex ante

Data/Parameter	EG _x	
Data unit	MWh/yr	
Description	Quantity of electricity supplied by the project power unit(s) with three years operational history and no retrofit in this period, to the electricity grid in year x	
Source of data	Generation records. Historical data of electricity supplied by the project to the grid in the defined operational history (see definitions)	
Value(s) applied		EG _x (MWh/y)
	Year 1393 (2013-2014)	2,271,800
	Year 1394 (2014-2015)	2,523,096
	Year 1395 (2015-2016)	2,390,038
Choice of data or measurement methods and procedures	3 years historical data prior to the project implementation from 21 March 2013 to 20 March 2016 are used (years 1393-1395 in Iranian calendar).	
Purpose of data	calculation of baseline emissions	
Additional comment	-	

Data/Parameter	$FC_{i,x}$	
Data unit	Mass or volume unit/yr	
Description	Quantity of fuel type <i>i</i> used by the project power unit(s) in year <i>x</i>	
Source of data	Historical data of annual fuel consumption by the project operating in single cycle mode	
Value(s) applied		$FC_{i,x}$ (Sm ³ /y)
	Year 1393 (2013-2014)	733,679,062
	Year 1394 (2014-2015)	832,106,127
	Year 1395 (2015-2016)	789,724,536
Choice of data or measurement methods and procedures	3 years historical data prior to the project implementation from 21 March 2013 to 20 March 2016 are used (years 1393-1395 in Iranian calendar).	
Purpose of data	calculation of baseline and leakage emissions	
Additional comment	-	

Data/Parameter	$NCV_{i,x}$	
Data unit	GJ/mass or volume unit	
Description	Net calorific value of fuel type <i>i</i> used by the project power unit(s) in year <i>x</i>	
Source of data	Values provided by the fuel supplier are used. This is the preferred source based on the methodology ACM0007 version 06.1.0.	
Value(s) applied		$NCV_{i,x}$ (GJ/Sm ³)
	Year 1393 (2013-2014)	0.0335
	Year 1394 (2014-2015)	0.0330
	Year 1395 (2015-2016)	0.0330
Choice of data or measurement methods and procedures	Values are based on compositions provided by the fuel supplier.	
Purpose of data	calculation of baseline and leakage emissions	
Additional comment	Only one fuel (natural gas) has been used in the gas turbines of the project activity. Hence, it's not required to determine the NCV of the least carbon intensive fuel that has been used before or after project implementation.	

Data/Parameter	$EF_{CO_2,min}$	
Data unit	tCO ₂ /GJ	
Description	CO ₂ emission factor of the least carbon intensive fuel type used by the project power unit(s) during the three years operational history	
Source of data	Values are based on the fuel composition provided by the fuel supplier. This is the preferred source based on the methodology ACM0007 version 06.1.0.	
Value(s) applied	0.0560	
Choice of data or measurement methods and procedures	Composition of natural gas samples has been provided by the fuel supplier.	
Purpose of data	calculation of baseline emissions	
Additional comment	<p>Only one fuel (natural gas) has been used in the gas turbines of the project activity. Hence, it's not required to determine the emission factor of the least carbon intensive fuel that has been used before or after project implementation, should be determined.</p> <p>Also the values are within the uncertainty range of the IPCC default values as provided in Table 1.3, Vol. 2 of the 2006 IPCC Guidelines.</p>	

Data/Parameter	CAP_{max}
Data unit	MW
Description	Maximum gross power generation capacity of the project power unit(s) prior to the implementation of the project activity
Source of data	Maximum generation capacity determined by performance tests under optimal operation conditions (optimal load, after maintenance, etc.)
Value(s) applied	972
Choice of data or measurement methods and procedures	The values are based on the manufacturer's specification.
Purpose of data	calculation of baseline emissions
Additional comment	-

Data/Parameter	T_{max}
Data unit	Hours/yr
Description	Maximum amount of time during a year in which the project power unit(s) could have operated at full power generation capacity prior to the implementation of the project activity
Source of data	calculated using HMR_x
Value(s) applied	8,433 (calculated as per equation 10)
Choice of data or measurement methods and procedures	this parameter is calculated using the average number of hours during which the plant did not operate due to maintenance or repair in year x (HMR_x)
Purpose of data	calculation of baseline emissions
Additional comment	-

Data/Parameter	HMR_x								
Data unit	Hours/yr								
Description	Average number of hours during which the plant did not operate due to maintenance or repair in year x (hours)								
Source of data	Project activity site								
Value(s) applied	<table border="1" style="width: 100%; border-collapse: collapse;"> <thead> <tr> <th></th> <th style="text-align: center;">HMR_x (hours/yr)</th> </tr> </thead> <tbody> <tr> <td>Year 1393 (2013-2014)</td> <td style="text-align: center;">372.5</td> </tr> <tr> <td>Year 1394 (2014-2015)</td> <td style="text-align: center;">454.1</td> </tr> <tr> <td>Year 1395 (2015-2016)</td> <td style="text-align: center;">154.1</td> </tr> </tbody> </table>		HMR_x (hours/yr)	Year 1393 (2013-2014)	372.5	Year 1394 (2014-2015)	454.1	Year 1395 (2015-2016)	154.1
	HMR_x (hours/yr)								
Year 1393 (2013-2014)	372.5								
Year 1394 (2014-2015)	454.1								
Year 1395 (2015-2016)	154.1								
Choice of data or measurement methods and procedures	Historical records for such maintenance and repair intervals are used.								
Purpose of data	calculation of baseline emissions								
Additional comment	-								

Data/Parameter	GWP _{CH4}
Data unit	tCO ₂ e/tCH ₄
Description	Global warming potential of methane valid for the relevant commitment period
Source of data	Standard for application of the global warming potentials to clean development mechanism project activities and programmes of activities for the second commitment period of the Kyoto protocol (Version 01.0)
Value(s) applied	25
Choice of data or measurement methods and procedures	According to the above standard, all emission reductions and removals achieved by CDM project activities and PoAs in the second commitment period of the Kyoto Protocol shall be calculated using the global warming potentials (GWPs) adopted by the Conference of the Parties serving as the meeting of the Parties at its seventh session, in accordance with decision 4/CMP.7 : <i>“For the second commitment period of the Kyoto Protocol, the global warming potentials used by Parties to calculate the carbon dioxide equivalence of anthropogenic emissions by sources and removals by sinks of greenhouse gases listed in Annex A to the Kyoto Protocol shall be those listed in the column entitled .Global Warming Potential for Given Time Horizon. in table 2.14 of the Errata to the contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, based on the effects of greenhouse gases over a 100-year time horizon, taking into account the inherent and complicated uncertainties involved in global warming potential estimates.”</i>
Purpose of data	calculation of leakage emissions
Additional comment	-

B.6.3. Ex ante calculation of emission reductions

>>

Ex-ante calculation of baseline emissions

Step A: Determination of the baseline emissions for different scenarios of project electricity generation

To determine the scenario of project electricity generation, the related parameters ($EG_{BLV,AVR}$, EG_{MAX} , $EG_{PJ,adj,y}$) should be calculated and compared first:

EG_{MAX}

EG_{MAX} is determined using equation 9:

$$EG_{MAX} = CAP_{max} \cdot T_{MAX}$$

Based on the data provided by the manufacturer of gas turbines, the maximum gross power generation capacity of the project power units (CAP_{max}) is 972MW. Also, T_{MAX} is calculated according to equation 10:

$$T_{MAX} = 8,760 - \frac{\sum_{x=1}^3 HMR_x}{3}$$

The values of HMR_x are as follows based on historical operation data:

	HMR _x (hours/y)
Year 1393 (2013-2014)	372.5
Year 1394 (2014-2015)	454.1
Year 1395 (2015-2016)	154.5

By using these data in equation 10, the value of T_{MAX} is obtained:

$$\begin{aligned}
 T_{MAX} &= 8,760 - \frac{\sum_{x=1}^3 HMR_x}{3} \\
 &= 8,760 - \frac{372.5 + 454.1 + 154.5}{3} \\
 &= 8,433 \text{ hr}
 \end{aligned}$$

EG_{MAX} is calculated as follows using equation 9:

$$\begin{aligned}
 EG_{MAX} &= CAP_{max} \times T_{MAX} \\
 &= 972MW \times 8,433 \text{ hr} \\
 &= 8,196,871 \text{ MWh/y}
 \end{aligned}$$

$EG_{BL,AVR}$

This parameter is calculated using equation 11:

$$EG_{BL,AVR} = \frac{\sum_{x=1}^3 EG_x}{3}$$

Following table shows the three years operational history of electricity supplied by the project power units (EG_x):

	EG_x (MWh/y)
Year 1393 (2013-2014)	2,271,800
Year 1394 (2014-2015)	2,523,096
Year 1395 (2015-2016)	2,390,038

Hence, $EG_{BL,AVR}$ is determined:

$$\begin{aligned}
 EG_{BL,AVR} &= \frac{\sum_{x=1}^3 EG_x}{3} \\
 &= \frac{2,271,800 + 2,523,096 + 2,390,038}{3} \\
 &= 2,394,978 \text{ MWh/y}
 \end{aligned}$$

$EG_{PJ,adj,y}$

Equation 12 should be used to obtain the value of $EG_{PJ,adj,y}$:

$$EG_{PJ,adj,y} = EG_{PJ,y} \times \frac{PJ_{min,y}}{PJ,y}$$

The actual capacity of the power plant operating in single cycle mode is 784 MW and it will be 1,176 MW after implementation of the project activity. Also, the average capacity factor of combined cycle power plants is 67.1% according to the national data. Hence, the value of $EG_{PJ,y}$ is estimated to be 6,912,481 MWh/y.

Based on national data, the average efficiency of combined cycle power plants is 44.1%. Since the project activity is not yet operational, it is considered that $\eta_{PJ,y} = \eta_{PJ,min,y} = 44.1\%$.

Using this data, $EG_{PJ,adj,y}$ is calculated as follows:

$$\begin{aligned} EG_{PJ,adj,y} &= EG_{PJ,y} \times \frac{PJ,min,y}{PJ,y} \\ &= 6,912,481 \text{ MW} \times \frac{0.441}{0.441} \\ &= 6,912,481 \text{ MW} \end{aligned}$$

The calculated values of $EG_{BLV,AVR}$, EG_{MAX} , $EG_{PJ,adj,y}$ are shown in table below:

$EG_{BLV,AVR}$	2,394,978 MWh/y
EG_{MAX}	8,196,871 MWh/y
$EG_{PJ,adj,y}$	6,912,481 MWh/y

As is shown in the above table, the quantity of electricity generated in the project power units, adjusted for changes to efficiency, ($EG_{PJ,adj,y}$) exceeds the historic average annual generation level ($EG_{BL,AVR}$), but is lower than the maximum annual quantity of electricity that the project power units could have produced prior to the implementation of the project activity (EG_{MAX}). Hence, as per methodology ACM0007 version 06.1.0, the case (b) is applicable for this ex-ante emission reduction calculations and the equation (7) should be used to calculate the baseline emissions:

$$BE_y = EG_{BL,AVR} \cdot EF_{CO2,BL,y} + (EG_{PJ,adj,y} - EG_{BL,AVR}) \cdot \min(EF_{CO2,BL}; EF_{grid,y})$$

Step B: Estimating the emissions factor for electricity generated in single cycle mode in the baseline ($EF_{CO2,BL}$)

As explained in section B.6.1, $EF_{CO2,BL}$ is determined by applying equation 14:

$$EF_{CO2,BL} = \frac{\sum_{x=1}^3 \sum_i FC_{i,x} \cdot NCV_{i,x}}{\sum_{x=1}^3 EG_x} \times EF_{CO2,min}$$

Only one fuel (natural gas) has been used by project power units during the three years operational history. The average CO₂ emission factor of this fuel is 0.0562 tCO₂/GJ for this three years period. The other historical data for calculation of $EF_{CO2,BL}$ are as table below:

	$FC_{i,x}$ (Sm ³ /y)	$NCV_{i,x}$ (GJ/Sm ³)	EG_x (MWh/y)
Year 1393 (2013-2014)	733,679,062	0.0335	2,271,800
Year 1394 (2014-2015)	832,106,127	0.0330	2,523,096
Year 1395 (2015-2016)	789,724,536	0.0340	2,390,038

Using these data in equation 14, the result for $EF_{CO2,BL}$ is 0.6083 tCO₂/MWh.

Step C: Determine the emissions factor for the grid electricity system ($EF_{grid,y}$)

As described in section B.6.1 above, the emission factor for the grid electricity system should be calculated as a combined margin emission factor, using the “Tool to calculate the emission factor for an electricity system”.

The combined margin emission factor is calculated in accordance with six steps provided by the “tool to calculate the emission factor for an electricity system” version 4.0. The results of calculations are shown in table below:

$EF_{grid,OM,y}$	0.7440 tCO ₂ /MWh
$EF_{grid,BM,y}$	0.6406 tCO ₂ /MWh
$EF_{grid,CM,y}$	0.6923 tCO ₂ /MWh

Finally, the baseline emissions are calculated as follows, using equation 7:

$$\begin{aligned}
 BE_y &= EG_{BL,AVR} \cdot EF_{CO_2,BL,y} + (EG_{PJ,adj,y} - EG_{BL,AVR}) \cdot \min(EF_{CO_2,BL}; EF_{grid,y}) \\
 &= 2,394,978 \times 0.6083 + (6,912,481 - 2,394,978) \times \min(0.6083; 0.6923) \\
 &= \mathbf{4,204,844 \text{ tCO}_2/y}
 \end{aligned}$$

Ex-ante calculation of project emissions

Project emissions are calculated using equation 2 as follows:

$$PE_y = PE_{FC,j,y} = \sum_i FC_{i,j,y} \times COEF_{i,y}$$

For ex-ante calculation of project emissions, the quantity of fuel combustion of the project activity ($FC_{i,j,y}$) is calculated using project activity electricity generation, average efficiency and average net calorific value of fuel as follows:

$$\begin{aligned}
 FC_{i,j,y} &= \frac{EG_{PJ,y} \times 3.6}{PJ,y \times NCV_{i,y}} \\
 &= \frac{6,912,481 \times 3.6}{0.441 \times 0.0332} \\
 &= 1,701,279,161 \text{ Sm}^3/y
 \end{aligned}$$

The CO₂ emission coefficient ($COEF_{i,y}$) is calculated according to the equation 4:

$$\begin{aligned}
 COEF_{i,y} &= w_{c,i,y} \times \rho_{i,y} \times 44/12 \\
 &= 0.696 \times 10^{-3} \text{ tC/kg} \times 0.7321 \text{ kg /Sm}^3 \times 44/12 \\
 &= 1.868 \times 10^{-3} \text{ ton CO}_2/\text{Sm}^3 \text{ fuel}
 \end{aligned}$$

Finally, project emissions are obtained:

$$\begin{aligned}
 PE_y &= \sum_i FC_{i,j,y} \times COEF_{i,y} \\
 &= 1,701,279,161 \text{ Sm}^3/y \times 1.868 \times 10^{-3} \text{ ton CO}_2/\text{Sm}^3 \\
 &= 3,178,533 \text{ ton CO}_2/y
 \end{aligned}$$

Ex-ante calculation of leakage emissions

Leakage emissions are determined using equation 21 as follows:

$$LE_{\text{upstream},y} = \max \left[0, \left(\sum_i (FC_{i,y} \cdot NCV_{i,y} \cdot EF_{i,\text{upstream},\text{CH}_4}) \cdot GWP_{\text{CH}_4} + LE_{\text{LNG},\text{CO}_2,y} \right) \cdot \left(1 - \frac{\frac{1}{3} \cdot \sum_{x=1}^3 \sum_i FC_{i,x} \cdot NCV_{i,x}}{\sum_i FC_{i,y} \cdot NCV_{i,y}} \right) \right]$$

Substituting of the ex-ante calculated values of $FC_{i,y}$ and $NCV_{i,y}$ and historical data ($FC_{i,x}$ and $NCV_{i,x}$) in above equation, the ex-ante value of $LE_{\text{upstream},y}$ is calculated as **121,578 tCO₂e/y**.

Ex-ante calculation of emission reductions

Emission reductions are calculated using equation 1 as follows:

$$\begin{aligned} ER_y &= BE_y - PE_y - LE_y \\ &= 4,204,844 - 3,178,533 - 121,578 \\ &= \mathbf{904,733 \text{ ton CO}_2/\text{y}} \end{aligned}$$

B.6.4. Summary of ex ante estimates of emission reductions

Year	Baseline emissions (t CO ₂ e)	Project emissions (t CO ₂ e)	Leakage (t CO ₂ e)	Emission reductions (t CO ₂ e)
Year 1	4,204,844	3,178,533	121,578	904,733
Year 2	4,204,844	3,178,533	121,578	904,733
Year 3	4,204,844	3,178,533	121,578	904,733
Year 4	4,204,844	3,178,533	121,578	904,733
Year 5	4,204,844	3,178,533	121,578	904,733
Year 6	4,204,844	3,178,533	121,578	904,733
Year 7	4,204,844	3,178,533	121,578	904,733
Year 8	4,204,844	3,178,533	121,578	904,733
Year 9	4,204,844	3,178,533	121,578	904,733
Year 10	4,204,844	3,178,533	121,578	904,733
Total	42,048,440	31,785,330	1,215,780	9,047,330
Total number of crediting years	10			
Annual average over the crediting period	4,204,844	3,178,533	121,578	904,733

B.7. Monitoring plan

B.7.1. Data and parameters to be monitored

Data/Parameter	EG _{PJ,y}
Data unit	MWh/yr
Description	Total amount of electricity supplied to the electricity grid by the project power units in year y
Source of data	Generation records
Value(s) applied	6,912,481
Measurement methods and procedures	This parameter will be measured using electricity meters.
Monitoring frequency	Continuously
QA/QC procedures	The consistency of metered net electricity generation will be cross-checked with receipts from sales (if available)

Purpose of data	Calculation of baseline emissions
Additional comment	-

Data/Parameter	$FC_{i,y}$
Data unit	Mass or volume unit/yr
Description	Quantity of fuel type <i>i</i> used by the project power unit(s) in year <i>y</i>
Source of data	Onsite measurements
Value(s) applied	1,707,279,161
Measurement methods and procedures	This parameter will be measured using flow meters.
Monitoring frequency	Continuously
QA/QC procedures	The consistency of metered fuel consumption quantities will be cross-checked by an annual energy balance that is based on purchased quantities and stock changes. The metered fuel consumption quantities will also be cross-checked with available purchase invoices from the financial records.
Purpose of data	Calculation of project emissions
Additional comment	-

Data/Parameter	$w_{C,i,y}$						
Data unit	tC/mass unit of the fuel						
Description	Weighted average mass fraction of carbon in fuel type <i>i</i> in year <i>y</i>						
Source of data	The following data sources may be used if the relevant conditions apply: <table border="1" style="width: 100%; border-collapse: collapse;"> <thead> <tr> <th style="width: 60%;">Data source</th> <th>Conditions for using the data source</th> </tr> </thead> <tbody> <tr> <td>(a) Values provided by the fuel supplier in invoices</td> <td>This is the preferred source</td> </tr> <tr> <td>b) Measurements by the project participants</td> <td>If (a) is not available</td> </tr> </tbody> </table>	Data source	Conditions for using the data source	(a) Values provided by the fuel supplier in invoices	This is the preferred source	b) Measurements by the project participants	If (a) is not available
Data source	Conditions for using the data source						
(a) Values provided by the fuel supplier in invoices	This is the preferred source						
b) Measurements by the project participants	If (a) is not available						
Value(s) applied	6.96×10^{-4}						
Measurement methods and procedures	Measurements will be undertaken in line with national or international fuel standards						
Monitoring frequency	The mass fraction of carbon should be obtained for each fuel delivery, from which weighted average annual values should be calculated						
QA/QC procedures	Verify if the values under a) and b) are within the uncertainty range of the IPCC default values as provided in Table 1.2, Vol. 2 of the 2006 IPCC Guidelines. If the values fall below this range collect additional information from the testing laboratory to justify the outcome or conduct additional measurements. The laboratories in b) should have ISO17025 accreditation or justify that they can comply with similar quality standards.						
Purpose of data	calculation of project emissions						
Additional comment	-						

Data/Parameter	$\rho_{i,y}$
Data unit	Mass unit/volume unit
Description	Weighted average density of fuel type <i>i</i> in year <i>y</i>

Source of data	The following data sources may be used if the relevant conditions apply:	
	Data source	Conditions for using the data source
	(a) Values provided by the fuel supplier in invoices	This is the preferred source
	b) Measurements by the project participants	If (a) is not available
	c) Regional or national default values	If (a) is not available This source can only be used for liquid fuels and should be based on well-documented, reliable sources (such as national energy balances).
Value(s) applied	0.7321	
Measurement methods and procedures	Measurements will be undertaken in line with national or international fuel standards	
Monitoring frequency	The density of the fuel should be obtained for each fuel delivery, from which weighted average annual values should be calculated	
QA/QC procedures	-	
Purpose of data	calculation of project emissions	
Additional comment	-	

Data/Parameter	$\eta_{PJ,y}$
Data unit	-
Description	Average energy efficiency of the project power unit(s) in year y of the crediting period
Source of data	Project activity site
Value(s) applied	44.1%
Measurement methods and procedures	The efficiency will be calculated using the direct method (dividing the net electricity generation by the energy content of the fuels fired during a representative time period) and not the indirect method (determination of fuel supply or heat generation and estimation of the losses); or using recognized standards for the measurement of the power plant efficiency. The efficiency has to be referred in terms of the net calorific values of the fuels used and the net electricity produced, i.e. total electricity produced minus internal consumption of electricity
Monitoring frequency	Once during each year y of the crediting period. The first calculation shall be made during the first year after implementing the project activity
QA/QC procedures	-
Purpose of data	Calculation of baseline emissions
Additional comment	-

Data/Parameter	$NCV_{i,y}$
Data unit	GJ/Sm^3
Description	Average net calorific value of fuel type <i>i</i> used by the project power unit(s) in year y

Source of data	Data source	Conditions for using the data source
	(a) Values provided by the fuel supplier in invoices	This is the preferred source
	b) Measurements by the project participants	If (a) is not available
	c) Regional or national default values	If (a) is not available These data should be based on well documented, reliable sources (such as national energy balances)
	(d) IPCC default values at the upper limit of the uncertainty at a 95% confidence interval as provided in Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories	If (a) is not available
Value(s) applied	0.0332	
Measurement methods and procedures	For (a) and (b): Measurements should be undertaken in line with national or international fuel standards. The NCV should be obtained for each fuel delivery, from which weighted average annual values should be calculated. For (c): review appropriateness of the values annually. For (d): any future revision of the IPCC Guidelines should be taken into account	
Monitoring frequency	Annually	
QA/QC procedures	It will be verified if the values under (a), (b) and (c) are within the uncertainty range of the IPCC default values as provided in Table 1.2, Vol. 2 of the 2006 IPCC Guidelines. If the values fall below this range additional information will be collected from the testing laboratory to justify the outcome or additional measurements will be conducted.	
Purpose of data	Calculation of leakage emissions	
Additional comment	As only one fuel is used in the gas turbines, the NCV of the least carbon intensive fuel (NG) that has been used before or after project implementation, will be determined The laboratories in (a), (b) or (c) should have ISO17025 accreditation or justify that they can comply with similar quality standards. This parameter is only required to calculate upstream leakage emissions, if applicable	

Data/Parameter	$EF_{i,upstream,CH_4}$
Data unit	tCH ₄ /GJ
Description	Emission factor for upstream fugitive methane emissions from production, transportation, distribution of fossil fuel <i>i</i> used by the project power unit(s) in year <i>y</i>

Source of data	<p>The following data sources may be used if the relevant conditions apply:</p> <table border="1" data-bbox="496 224 1433 1787"> <thead> <tr> <th data-bbox="496 224 999 293">Data source</th> <th data-bbox="999 224 1433 293">Conditions for using the data source</th> </tr> </thead> <tbody> <tr> <td data-bbox="496 293 999 658">(a) Reliable and accurate national data on fugitive CH4 emissions associated with the production, transportation and distribution of the fuels. GHG inventory data reported to the UNFCCC as part of national communications can be used where country-specific approaches (and not IPCC Tier 1 default values) have been used to estimate emissions</td> <td data-bbox="999 293 1433 658">This is the preferred source</td> </tr> <tr> <td data-bbox="496 658 999 1787"> <p>b) Default emission factors</p> <table border="1" data-bbox="517 689 981 1543"> <thead> <tr> <th data-bbox="517 689 798 786">Activity</th> <th data-bbox="798 689 901 786">Unit</th> <th data-bbox="901 689 981 786">Default emission factor</th> </tr> </thead> <tbody> <tr> <td colspan="3" data-bbox="517 786 981 815">Coal</td> </tr> <tr> <td data-bbox="517 815 798 853">Underground mining</td> <td data-bbox="798 815 901 853">tCH4 / kt coal</td> <td data-bbox="901 815 981 853">13.4</td> </tr> <tr> <td data-bbox="517 853 798 891">Surface mining</td> <td data-bbox="798 853 901 891">tCH4 / kt coal</td> <td data-bbox="901 853 981 891">0.8</td> </tr> <tr> <td colspan="3" data-bbox="517 891 981 920">Oil</td> </tr> <tr> <td data-bbox="517 920 798 958">Production</td> <td data-bbox="798 920 901 958">tCH4 / PJ</td> <td data-bbox="901 920 981 958">2.5</td> </tr> <tr> <td data-bbox="517 958 798 996">Transport, refining and storage</td> <td data-bbox="798 958 901 996">tCH4 / PJ</td> <td data-bbox="901 958 981 996">1.6</td> </tr> <tr> <td data-bbox="517 996 798 1034">Total</td> <td data-bbox="798 996 901 1034">tCH4 / PJ</td> <td data-bbox="901 996 981 1034">4.1</td> </tr> <tr> <td colspan="3" data-bbox="517 1034 981 1064">Natural gas</td> </tr> <tr> <td colspan="3" data-bbox="517 1064 981 1093"><i>USA and Canada</i></td> </tr> <tr> <td data-bbox="517 1093 798 1131">Production</td> <td data-bbox="798 1093 901 1131">tCH4 / PJ</td> <td data-bbox="901 1093 981 1131">72</td> </tr> <tr> <td data-bbox="517 1131 798 1169">Processing, transport and distribution</td> <td data-bbox="798 1131 901 1169">tCH4 / PJ</td> <td data-bbox="901 1131 981 1169">88</td> </tr> <tr> <td 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B.7.2. Sampling plan

>>

It is not applicable for this project activity.

B.7.3. Other elements of monitoring plan

>>

This monitoring plan is compiled in line with the selected monitoring methodology ACM0007/Version 06.1.0. The aim of monitoring procedure is to make sure that the data monitored and evaluated during the project activity operation period is completed, consistent, and precise.

CDM project team

Project owner will set up a CDM team, which will be responsible for data recording, collection, reporting and preservation. This team will be composed by the project manager, technicians, and statisticians.

The detailed structure is shown in figure B-1:

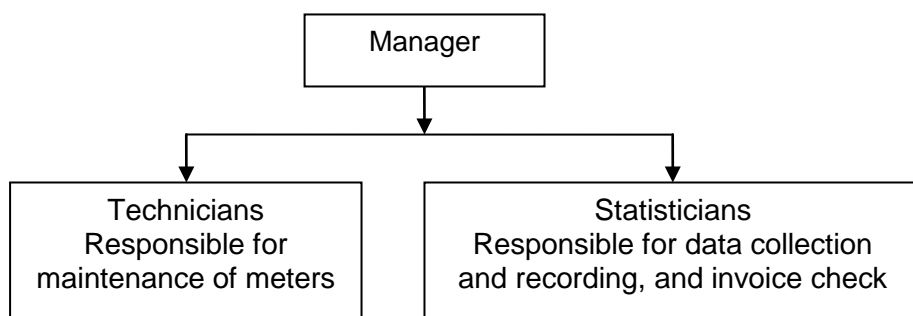


Figure B-1: Management structure of the monitoring activity

Responsibility of Statisticians:

1. Monitors the required parameters:
2. Records and archives data using computer software. The records will serve as back-up purpose and archived at Project site. All the data will be kept at least for 2 years after the end of the crediting period.
3. Compiles and analyzes the monthly monitoring reports and cross-checks the monitoring report data against electricity sales receipts.
4. Elaborates an estimate of emission reduction in an Emission Reduction Monitoring Report annually.
5. Ensures that operators are appropriately trained and assigned for monitoring/checking the different parameters/meters with classes and an instruction manual.
6. Reviews the instruction manual for its effectiveness and improvement. This manual will be made available during verification.

1. Ensures that all meters installed at the plant are calibrated according to national industrial standards.
2. Ensures that all meters are operating properly, and requests to repair or replace the meters in case of any malfunction.
3. Elaborates the Calibration Report annually. The Calibration Report is composed listing all CDM-related instruments, their details, calibration status and expected error.

Responsibility of manager:

1. Manages and supervises all monitoring activities under the project.
2. Review and approve the Emission Reduction Monitoring Report with all its attachments that will be verified by the DOE.

3. Subjects the Calibration Report Status to internal audit and provides as an attachment in the annual Emission Reduction Monitoring Report, for verification.

Examination and Calibration

The electric meters should be examined and undergo regular field calibration according to the relevant standards and regulations of the power industry so as to ensure the sophistication of the meters. After the examination and calibration, the meters should be sealed. All the meters installed shall be tested and calibrated annually, by an accredited metering verification institution for:

- (a) Detection of a difference larger than the allowable error in the readings of meters
- (b) Repair of meters in case of any failure of one or more parts to operate in accordance with the specifications. In case of irreparable damage of the meters, they shall be changed.

Staff training

All new staff will undergo “on job training” covering the monitoring requirements at least once a year. Any of the staff may receive any specific training during the year.

- The monitoring plan will be made available to each staff involved in the monitoring in the local language. A copy is located in the control room at the site.
- Type of training required will be identified from training need analysis conducted annually. The record of training and awareness should be kept for at least 2 years after the crediting period.
- During the training, staffs are required to sign training attendance list.

Regular meetings will be organized to ensure that the personnel are aware of the relevance and importance of its activities and how it is contributing to the achievement of the quality monitoring plan.

SECTION C. Start date, crediting period type and duration

C.1. Start date of project activity

>>

31/05/2014

C.2. Expected operational lifetime of project activity

>>

20 years and 0 months

C.3. Crediting period of project activity

C.3.1. Type of crediting period

>>

Fixed crediting period (10 years)

C.3.2. Start date of crediting period

Responsibility of maintenance Technicians:

01/07/2018

C.3.3. Duration of crediting period

>>

10 years and 0 months

SECTION D. Environmental impacts

D.1. Analysis of environmental impacts

>>

Stakeholder's comment form questioning the effects of the project on local environment, employment, economy, sustainability and technical improvement.

In addition to this meeting, the Iranian Designated National Authority (DNA) for the CDM requires the compulsory invitation of selected stakeholders to comment the PDD sent to validation in order to provide the letter of approval.

The invited local stakeholders are listed below:

- Department of Environment
- Ministry of Housing and Urban Development
- Ministry of Petroleum
- Ministry of Energy
- Ministry of Industry, Mine and Trade
- Ministry of Jihad Agriculture
- Ministry of Road and Transportation (Meteorological Organization)
- Ministry of Economic Affairs and Finance
- Ministry of Defence
- Ministry of Information and Communications Technology
- Ministry of Health and Medical Education
- Ministry of Foreign Affairs
- Ministry of Interior (Municipalities and Rural Management Organization)
- Ministry of Science, Research and Technology
- President Deputy Strategic Planning and Control

E.2. Summary of comments received

>>

The stakeholders thanked the project promoter for investing in combined cycle power generation. Moreover, they suggested implementing more environmental projects in other nearby gas processing and petrochemical plants for improvement of living conditions in Asalouyeh. The survey (by Stakeholder's Comment Form) shows that the stakeholders have positive attitude toward the project activity and its effects on living conditions, economy and employment status in local community. Also none of the attendees believe that the project would have miserable impact on the local environment.

The following questions and answers were expressed during the meeting:

Q1: How much job will be created by implementation of the project?

R1: Currently, about 200 people are working in construction phase; this will be increased to 600-1000 jobs during the peak period of the construction. Also about 100 people will be needed for operation of the project.

Q2: How many CDM projects have been registered in Iran and in which sectors?

R2: 14 CDM projects have been registered in Iran until now. These projects are in the fields of fuel switching, combined cycle power generation, landfill gas recovery, hydropower, and N₂O abatement.

Q3: How will the local community be benefitted from CDM registration of the project?

R3: Based on the rules of procedures for DNA of Iran, 3% of CDM incomes of every project should be utilized for sustainable development purposes in the project area.

E.3. Consideration of comments received

>>

As explained in section E.2, the stakeholders have no negative comments on the project. Therefore, it is not necessary to take any additional measure.

SECTION F. Approval and authorization

>>

Letter of Approval from DNA of Iran is not available at the time of submitting the PDD to the validating DOE. It will be issued after commencement of the validation.

Appendix 1. Contact information of project participants

Organization name	National Iranian Oil Company (NIOC)
Country	Iran
Address	No. 18 (3 rd NIOC Central Building), Roodsar St., Hafez-Taleghani Ave., Tehran
Telephone	+98 21 88943712
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Appendix 2. Affirmation regarding public funding

The project has not received any type of public finding or public financial help.

Appendix 3. Applicability of methodologies and standardized baselines

Not Applicable

Appendix 4. Further background information on ex ante calculation of emission reductions

Not Applicable

Appendix 5. Further background information on monitoring plan

Not Applicable

Appendix 6. Summary report of comments received from local stakeholders

Not Applicable

Appendix 7. Summary of post-registration changes

Not Applicable

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Document information

<i>Version</i>	<i>Date</i>	<i>Description</i>
10.1	28 June 2017	Revision to make editorial improvement.
10.0	7 June 2017	Revision to: <ul style="list-style-type: none"> • Improve consistency with the “CDM project standard for project activities” and with the PoA-DD and CPA-DD forms; • Make editorial improvement.
09.0	24 May 2017	Revision to: <ul style="list-style-type: none"> • Ensure consistency with the “CDM project standard for project activities” (CDM-EB93-A04-STAN) (version 01.0); • Incorporate the “Project design document form for small-scale CDM project activities” (CDM-SSC-PDD-FORM); • Make editorial improvement.
08.0	22 July 2016	EB 90, Annex 1 Revision to include provisions related to automatically additional project activities.
07.0	15 April 2016	Revision to ensure consistency with the “Standard: Applicability of sectoral scopes” (CDM-EB88-A04-STAN) (version 01.0).
06.0	9 March 2015	Revision to: <ul style="list-style-type: none"> • Include provisions related to statement on erroneous inclusion of a CPA; • Include provisions related to delayed submission of a monitoring plan; • Provisions related to local stakeholder consultation; • Provisions related to the Host Party; • Make editorial improvement.
05.0	25 June 2014	Revision to: <ul style="list-style-type: none"> • Include the Attachment: Instructions for filling out the project design document form for CDM project activities (these instructions supersede the "Guidelines for completing the project design document form" (Version 01.0)); • Include provisions related to standardized baselines; • Add contact information on a responsible person(s)/ entity(ies) for the application of the methodology (ies) to the project activity in B.7.4 and Appendix 1; • Change the reference number from F-CDM-PDD to CDM-PDD-FORM; • Make editorial improvement.
04.1	11 April 2012	Editorial revision to change version 02 line in history box from Annex 06 to Annex 06b.
04.0	13 March 2012	Revision required to ensure consistency with the “Guidelines for completing the project design document form for CDM project activities” (EB 66, Annex 8).

<i>Version</i>	<i>Date</i>	<i>Description</i>
03.0	26 July 2006	EB 25, Annex 15
02.0	14 June 2004	EB 14, Annex 06b
01.0	03 August 2002	EB 05, Paragraph 12 Initial adoption.

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