Project design document form for CDM project activities

(Version 05.0)

Complete this form in accordance with the Attachment "Instructions for filling out the project design document form for CDM project activities" at the end of this form.

PROJECT DESIGN DOCUMENT (PDD)	
Title of the project activity	Genaveh Combined Cycle Power Plant
Version number of the PDD	PDD v.2.1
Completion date of the PDD	16/09/2014
Project participant(s)	Mapna Genaveh Power Generation Co. (Private entity) Swiss Carbon Assets Ltd. (Private entity)
Host Party	Islamic Republic of Iran
Sectoral scope and selected methodology(ies), and where applicable, selected standardized baseline(s)	Sectoral Scope : 1 AM0029 Version 03, "Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas"
Estimated amount of annual average GHG emission reductions	702,849 tonnes of CO2

SECTION A. Description of project activity

A.1. Purpose and general description of project activity

The proposed project activity is the construction and operation of a new combined cycle gas power plant. The project activity is located in the province of Bushehr, in south-west part of Islamic Republic of Iran.

Purpose of the proposed project activity:

- Scenario existing prior to the start of the implementation of the project activity:

  No power plant operating in the project site. Therefore, scenario existing prior to the implementation of the project activity would be the electricity generation by the other gas fired power plants in the vicinity of Genaveh in the grid.
- Project scenario

  The project activity consists in the construction of a greenfield combined cycle power plant. Overall, the proposed project activity will have a gross capacity of 484 MW according to EPC contract.

- Baseline scenario

  The baseline scenario is equivalent to the construction of an open cycle gas fired power plant of 3x 159 MW capacity to meet the local electricity demand.

Reduction of greenhouse gases:

Combined cycle power plants are more efficient than open cycle ones. This increase in efficiency will lead to the production of the same amount of electricity as in the baseline, while decreasing fossil fuel consumption. This decrease in fossil fuel consumption reduces overall CO2 emissions.

Contribution to sustainable development:

The proposed project activity contributes to sustainable development in Iran through a number of ways:

- More efficient use of Iran’s gas reserves: the efficiency gains achieved by the construction of combined cycle as opposed to open cycle power plants will help preserve finite fossil fuel resources
- Ensuring stable supplies of electricity: The proposed project activity will contribute to providing stable power supplies to the population and industries of Iran, while limiting the increase of fossil fuel consumption.
- Technology and know-how transfer: the proposed project activity will lead to training of the local staff, and help the spread of modern power plant technology in Iran.

Annual average and total GHG emission reductions for chosen crediting period:

Expected annual average GHG emission reductions: 702,849 tCO2e/year

Total expected GHG emission reductions over 10 years: 7,028,490 tCO_2e

A.2. Location of project activity

A.2.1. Host Party

Islamic Republic of Iran

A.2.2. Region/State/Province etc.

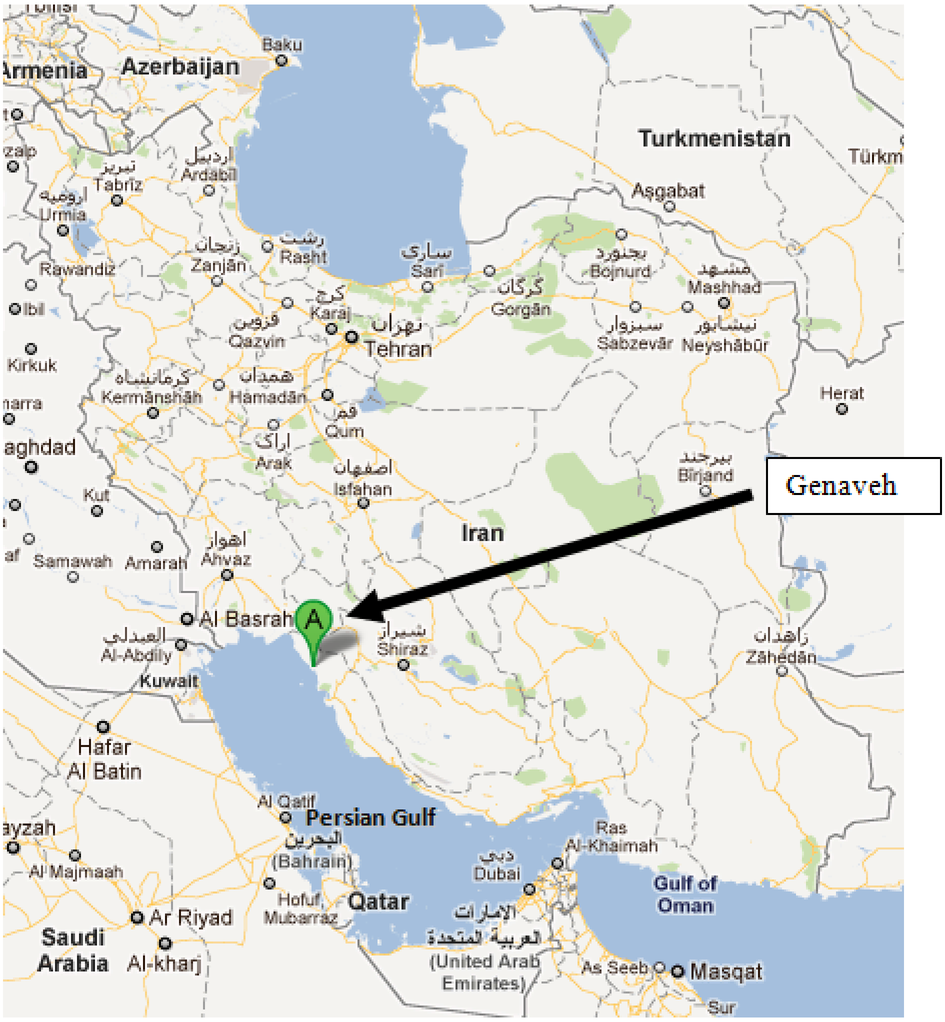
Bushehr Province

A.2.3. City/Town/Community etc.

Genaveh

A.2.4. Physical/Geographical location

Genaveh is in the province of Bushehr, in south-west part of Iran, as shown on the map below.



The power plant is located about 15 km southwest of Genaveh.

Geographical coordinates:

- Site latitude: 29.541111 (North)
- Site longitude: 50.712222 (East)

A.3. Technologies and/or measures

Scenario existing prior to the start of the implementation of the project activity:

Other gas fired power plants in the vicinity of Genaveh supply the city and the grid with electricity. No power plant is operating in the site of the proposed project activity.

The proposed project activity consists in the construction of a Greenfield combined cycle power plant including the following components:

- Two natural gas turbine-generators
- One steam turbine-generator

The particulars of the gas turbines[1]:

Turbine Model	V94.2
Number of Shafts	Single
Ability for dual fuel operation	Yes
Rotor speed	3000 rpm
Gross capacity:	2 x 162 MW*
Number of shafts	1
Number of stages	16
Pressure ration	11.7
Rotor speed	3000 rpm
Number of shafts	1
Number of stages	4
Method of cooling	Air from compressor
Rotor structure	Disk type
Combustion system	
Type and number of combustion chambers	2 Vertical (Silo)
Pressure of fuel at burners (bar g)	Min 18 Max 19 Normal 18.5

* Source: ECA schedule 1

The particulars of the steam turbines[2]:

Turbine	
Manufacturer	TUGA

[1] Extracts from Mapna EPC document

[2] Extracts from MAPNA EPC contract

Model	Type E30-16-1*6.3
Number of cylinders	1 (outer casing)
Rotor	
Number of rotors	1
Type of rotor	Forged monoblock
Number of HP stages	24
Number of LP stages	7
Gross output	1x160MW*
HP steam conditions for MCR[3]	• Pressure: 90 bar(a) • Temperature: 520 C • Flow: 134 kg/s
LP steam conditions for MCR	• Pressure: 8 bar(a) • Temperature: 230 C • Flow: 14 kg/s
Power Factor	0.8
Turbine type	Condensing

* Source: ECA schedule 1

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The particulars of HRSGs[4]:

HP Section	
Feed water	67 Kg/Sec
Live Steam	67 Kg/Sec
Temperature/Steam - Live Steam at Battery Limit (ST Inlet)	520 C
Pressure/Steam – Live Steam at Battery Limit (CT Inlet)	90 Bar(a)
Pressure drop of water/Steam – Across economizer 1	0.49 Bar
Pressure drop of water/Steam – Across economizer 2	1.71 Bar
Pressure drop of water/Steam – Across super heater 1	0.9 Bar
Pressure drop of water/Steam – Across super heater 2	1.2
Pressure drop of water/Steam – Across super heater 3 (if applicable)	1.2
LP Section	
Feed water	9 Kg/Sec
Live steam	9 Kg/Sec
Temperature – Live Steam at Battery limit (ST inlet)	230 C
Pressure – Live Steam at Battery Limit (ST Inlet)	0.5 Bar (a)

3 Maximum Continuous Rating

4 Extracts from MAPNA EPC contract

Moisture Carryover	0.01%
Mass Flow	509.11 Kg/Sec
Temperature	Before D/B: 548.30 C After D/B: 563.93 C
Efficiency (Heat Losses as % of Heat Input)	79.5 %

Model number of gas turbines, gas turbine generators and steam turbine generators are as followings[5]:

Turbine			
Unit	Manufacturing year	Serial No.	Unit No.
First gas	2010	T15188	127
Second gas	2010	T14899	130
Steam	2010	T15729	32

Generator			
Unit	Manufacturing year	Serial No.	Model
First gas	2010	P.124	TY10546
Second gas	2010	P.126	TY10546
Steam	2010	S.30	TLRI 115/41

The overall gross capacity of power plant is 484 MW according to the ECA.

The combined cycle power plant has an expected overall lifetime of 25 years[6].
The combined cycle power plant is designed for a load factor of 91.64%[7].
The combined cycle power plant has a design efficiency of 46.3%[8]

Monitoring equipment:

The fuel consumption will be measured by gas flow meters (for natural gas). Electricity meters measuring the amount of electricity produced by the generators and the auxiliary consumption of the power plant will be installed. All meters will be subject to regular maintenance in line with manufacturer manual.

The baseline scenario is the construction of an open cycle power plant using Natural gas with equivalent capacity than the combined cycle one.

Involved greenhouse gases: CO_2.

For calculation of expected emission reductions the following yearly energy and mass flows are assumed.

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[5] Source: Mapna EPC confirmation: CR3. Serial_numbers

[6] Source: Tool to determine the remaining lifetime of equipment Version 01

[7] Source: Genaveh Feasibility Study

[8] Source: ECA contract.

Year	$EG_{PJ,y}$ (MWh/year)	$FC_{NG,y}$ (Nm3)
1	3,419,874	719,139,936
2	3,419,874	719,139,936
3	3,419,874	719,139,936
4	3,419,874	719,139,936
5	3,419,874	719,139,936
6	3,419,874	719,139,936
7	3,419,874	719,139,936
8	3,419,874	719,139,936
9	3,419,874	719,139,936
10	3,419,874	719,139,936

Know-how transfer:

The generators and turbines used in the power plant are manufactured by subsidiaries of MAPNA group, under licence from Siemens. The local production of components used in the generators and turbines increases the local capacities and the know-how related to power plant engineering.

A.4. Parties and project participants

Party involved (host) indicates host Party	Private and/or public entity(ies) project participants (as applicable)	Indicate if the Party involved wishes to be considered as project participant (Yes/No)
Islamic Republic of Iran (host)	Mapna Genaveh Power Generation Co. (Private entity)	No
Islamic Republic of Iran (host)	Swiss Carbon Assets Ltd. (Private entity)	No

A.5. Public funding of project activity

There is no public funding for the project activity from Parties included in Annex I.

SECTION B. Application of selected approved baseline and monitoring methodology and standardized baseline

B.1. Reference of methodology and standardized baseline

AM0029 Version 03, “Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas”

“Tool to calculate the emission factor for an electricity system”, Version 4.0

“Tool for the demonstration and assessment of additionality”, Version 7.0.0

B.2. Applicability of methodology and standardized baseline

Applicability criteria of the methodology AM0029, Version 03

The project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant[9].

The proposed project activity involves the construction and operation of a new natural gas fired combined cycle grid-connected electricity generation plant. Natural gas will be the primary fuel. Small amounts of other start-up or auxiliary fuels (Diesel) might be used, but will comprise no more than 1% of total fuel use, on energy basis.

The geographical/physical boundaries of the baseline grid can be clearly identified and information pertaining to the grid and estimating baseline emissions is publicly available

The boundaries of the baseline grid (National grid) can be clearly identified and information pertaining to the grid and baseline emissions is publicly available from Tavanir, Ministry of Energy of Iran. See section B.6.1 for the calculation of the baseline grid emission factor.

Natural gas is sufficiently available in the region or country, e.g. future natural gas based power capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity[10].

Iran has the second biggest gas reserves in the world[11]. It has ambitious plans to further the natural gas extraction over the next few years, so no shortage of natural gas is foreseeable. Therefore future natural gas based power capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity. Following paragraphs describe more in detail about this issue.

Abundance of natural gas in Iran and the region of the project activity:

The spirit of emphasizing "sufficient availability" of Natural Gas in the methodology as an applicability criterion is:

(a) To ensure that NG from other users are not diverted and

(b) To ensure future power generation facilities of comparable size are not deprived due to NG being taken up by the project activity [Footnote No.2 of the AM0029, Version 3]

The points (a) and (b) above are borne out by the clarification [F-CDM-AM-Clar_Resp_ver 01.1 - AM_CLA_0091] issued by EB in response to a DOE query. In the response, EB also clearly mentions how the applicability condition pertaining to availability is to be implemented. In EB`s view, a project activity to demonstrate that it meets the applicability

[9] *Natural gas should be the primary fuel. Small amounts of other startup or auxiliary fuels might be used, but will comprise no more than 1% of total fuel use, on energy basis.*

[10] *In some situations, there could be price-inelastic supply constraints (e.g. limited resources without possibility of expansion during the crediting period) that could mean that a project activity displaces natural gas that would otherwise be used elsewhere in an economy, thus leading to possible leakage. Hence, it is important for the project proponent to document that supply limitations will not result in significant leakage as indicated here.*

[11] https://www.cia.gov/library/publications/the-world-factbook/rankorder/2179rank.html

condition will need to do so by resorting to appropriate monitoring. The relevant excerpt from EB`s clarification – "*the monitoring should show that satisfying the project activity`s demand for natural gas will not lead to shortage in supplies of the gas to other projects within the country".*

The applicability condition in the methodology aims to avoid the diversion of natural gas from other future and existing users. It is evident from AM0029 applicability condition on sufficient availability "future natural gas based power capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity".

Iran has the second largest gas reserves in the world (around 16% of overall reserves in the world[12]) after Russia and is uniquely positioned in the global gas market representing one of the largest potential new suppliers to both eastern and western markets Iran is the third-largest natural gas producer in the world due in part to the development of the super-giant South Pars field. South Pars is part of a wider gas field that is shared with Qatar. Moreover, Iran is currently the largest producer of and consumer of natural gas in Middle East[13].

At the time of initiation of the project activity, natural gas was sufficiently available for procurement and there have been no evident restrictions caused by the project activity`s choice of natural gas as the fuel, on significant future capacity additions to the baseline grid comparable in size to the project activity, in choosing natural gas as fuel. Some of the examples of sufficient availability of natural gas in the market in Genaveh, in which province the project activity is located are explained in the following paragraphs. The following table indicates the geographical distribution of natural gas in Iran:

Geographical distribution of gas production in Iran (MCM[14])			
Region	**2005-06**	**2006-07**	**2007-08**
Khuzestan	10085	10320.8	11534
Kangan	33441.3	33226.6	31061.5
Dalan	846.8	2356.6	2117
Sarajeh	255.5	158	73
Khorasan	12504.9	12764.3	12921.1
South Pars (Genaveh)	40175.3	43365.5	44785.5
Parsian	2011.2	8309.4	22301.5
Hormozgan	5602.8	5573.9	5146.5
Aghaz	1467.3	1190.7	1825.0
Ilam (Eslam Abad)	-	-	146
Total	106372	117265.8	131946.5

Source: Iran Energy Balance Sheet 2007-2008[15]

[12] http://www.infoplease.com/ipa/A0872966.html

[13] International Energy Agency, Source: IEA_2007

[14] Million Cubic Meter

Table below provides the gas production (in MCM) in the state during 2003-2008:

Year	Genaveh (South Pars)	Iran total	% of state in total production
2003-2004	19458.2	86395.5	22.52%
2004-2005	29670.9	99243.5	29.89%
2005-2006	40157.3	106372.0	37.71%
2006-2007	43365.5	117265.8	36.98%
2007-2008	44785.5	131946.5	33.94%

Source: Iran Energy Balance Sheet 2007-2008[16]

For the project activity, Tavanir has made an agreement with project participant for the gas supply quantity of minimum 2.14 MCMD[17] natural gas till the end of project operation. As can be seen, the project activity has agreement[18] for utilizing annual 719 MCM (considering 2,14 MCMD for 365 days operation) of natural gas against the total production of 43365.5 MCM of natural gas in South Pars in 2006-07. This was only less than 2% of the natural gas production in South Pars for the year.

The following table also provides the discoveries of reserves of natural gas in Iran[19]:

Natural gas reserves		
Year	Basin/field	Initial reserve (BCM[20])
2002	Maroun	175
2002	Dey	125
2003	Ofogh	99
2004	Lavan	258
2004	Hoseinieh	276
2005	Balal	249
2006	Kish	1703.2
2007	Ahvaz	21.5
2008	Dahrom	480.8
2008	Kooh Asmari	27.5
2008	Farsi	508.8
Total	-	3923.8

15 Energy_balance_sheet_Natural gas reseves_2007_08

16 Energy_balance_sheet_Natural gas reseves_2007_08

17 Feasibility study report , MCMD is the abbreviation for Million Cubic Meter per Day

18 Refer to the article 6 of ECA contract that obliges Tavanir to supply Natural Gas for the whole operation period

19 Energy_balance_sheet_explorations

20 Billion Cubic Meter

As can be seen from the above table, natural gas reserves are sufficiently and enormously available in the country and the time of real action of the project activity just the discovered reserves (note those that have been already discovered) were to the order of 3923.8 BCM in comparison to the supply commitment of by Tavanir towards the project activity of 2.14 MCMD (which is equivalent to 719 MCM considering an operation of 365 days in a year). This means that the commitment of natural gas quantity to the project activity by Tavanir is only 0.01% (719/3923800) of the total reserves of natural gas during the investment period and the available reserves are capable of firing thousands times the installed capacity of project activity.

The following paragraphs also elaborate on the sufficient supply of the natural gas versus demand projection of the use of the natural gas in Iran and the Genaveh.

The "price inelastic" supply constraints can occur mainly in the case where no possibility of expansion of natural gas reserves is or the demand projection of natural gas is more than the supply projection of natural gas in the region. The following paragraph elaborates on the demand supply positions and also the future of the natural gas reveres in the city of Genaveh where Genaveh CC power plant is located.

Demand and supply projections of natural gas:
Iran still has huge potential for new significant gas discoveries: areas like Caspian Sea, North East, Central Kavir and especially areas starting from Aghar and Dalan gas fields in Fars province up to the Strait of Hormuz and Central Persian Gulf have considerable amount of undiscovered gas resources[21].

According to the Iranian development plan, the next 10 years will witness a stronger growth in the country`s rich gas production, says the Minister of Petroleum. This will raise Iran`s natural gas production on an average annual 14% growth to 1.510 MCMD by 2014, from 560 MCMD of today and 700 MCMD by end of 2007 (Minister of Petroleum, 12th Annual Asia Oil and Gas Conference (AOGC) 2007[22]).

Moreover, National Iranian Oil Company (NIOC) is keen to award new phases of South Pars that are geared toward supplying for domestic use. In 2006, a group of international companies, including Shell and Total, won qualification for South Pars Phases 19-22, a USD 5 Billion project that calls for production of 40 BCM per year of gas[23].

Given the information above, calculation of future trends will prove that Iran will never have the shortages of any type in supplying gas for domestic purposes, including power generation plants.

[21] http://pubs.usgs.gov/fs/fs-0008-02/fs-0008-02.pdf

[22] http://www.payvand.com/news/07/jun/1101.html

[23] International Energy Agency, Source: IEA_2007

Item	2007	2008	2009	2010	2011	2012
Current production (MCMD) Scenario - I 14% growth[24]	295[25]	337	384	437	499	568
Current consumption (MCMD) – Scenario - I (3.8% growth[26])	269	279	290	301	312	324

As can be seen above, future projects demonstrate that the supply of natural gas exceeds demand in near future.

Moreover, the power plant is expected to consume 89000[27] CMH[28] (site condition) equalling to 2.14 MCMD. This means that in 2012, about 113 of similar plants can be added to the network. This clearly shows that construction of such a power plant does not deprive the supply of natural gas to any other type of industrial/commercial use.
Future forecast of natural gas based power plants prove that, in case of adding new power plants, natural gas will be sufficiently available. Following table shows the consumption forecast in power plants versus excess supply forecast (calculated in the previous table):

Year	2007	2008	2009	2010	2011	2012
Consumption forcast	8.04	16.07	24.11	32.14	40.18	48.22
Excess supply forcast	13	28	47	68	93	122
Remaining (MCMD)	4.96	11.93	22.89	35.86	52.82	73.78

Therefore in case of construction of future power plants, natural gas will be available.

It is noteworthy to express that the parliament of Iran just recently called for gas to be used for the petrochemicals sector and other industrial, power generation, transportation and residential use within the country. National Iranian Oil Company (NIOC) analysed that Iran will still have a massive 12000-14000 BCM left over for export after covering domestic needs and gas re-injection for 50 more years. In addition, the recent gas discoveries and investment made by foreign giant companies in South Pars basin in the vicinity of Genaveh

[24] Iranian Minister of Petroluem, http://www.payvand.com/news/07/jun/1101.html

[25] Production and consumption data are based on the British Petroleum (BP) report in 2007. Data of 2006 has been used and multiplied by growth rates of different scenarios. Source: BP_report_2007 pages 25 and 27

[26] Rates calculated by Baker Institute : Baker_institute_report_may_2008

[27] Feasibility study report, page 23 on daily hour consumption of natural gas.

[28] Cubic Meter per Hour

city, are expected to significantly augment the gas supply provision in Iran in general and Genaveh in particular[29].

Based on the energy balance report of Iran in 2006-7 the demand from consumers having firm committed supply in province of Bushehr in the year 2006-7 was 23.02 MCMD[30]. On the other hand the availability of natural gas in South Pars in 2006-7 was 118.81 MCMD (dividing 43365.5 MCM by 365). This shows that the supply of natural gas in South Pars in the vicinity of Bushehr province where the project is located is far beyond the demand. The oversupply of 95.79 MCMD can afford the natural gas needed for 44 of similar project activities. This again proves that the establishment of such a power plant does not deprive other activities or does not cause shortages of natural gas.
Moreover, the existing reserve of South Pars is estimated to be 51 TCM[31] (It should be noted again that South Pars is one of the largest gas fields in the world). The recent discoveries and investments that have been made are estimated to raise the supply of gas from this field (South Pars) 750 MCMD. This if be added to the network, releases enormous amount of natural gas. Let us have a look on the natural gas pipeline network in the following paragraphs.

Iran has an extensive natural gas pipeline system that includes trunklines, import/export pipelines, and gathering and distribution lines. The backbone of the domestic pipeline system is the Iranian Gas Trunkline (IGAT) pipeline series, which transports natural gas from processing plants to end-use consumers. Development of IGAT pipelines, fed by South Pars development phases, is important to Iran's natural gas transport. IGAT-8 will run nearly 650 miles to Iran's northern consumption centres, including Tehran. IGAT-9 and IGAT-10 are still in the planning and construction phase and are not likely to become operational before 2017[32].

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29 International Energy Agency, IEA_2007

30 Energy_balance_sheet_prvincal_demand_2007_2008

31 Trillion Cubic Meter, http://www.payvand.com/news/10/jun/1138.html

32 EIA_report_Iran_Natural_Gas

During 2002 to 2007 1962 Km of gas transmission pipelines have been constructed per annum. In overall, until the end of 2007, 27737 Km of gas pipeline have been constructed. Following table provides the trend of construction of gas pipeline[33]:

Detail/year	2002	2003	2004	2005	2006	2007	2008
Length of pipeline (Km/year)	1300	1100	1183	2173	2249	2910.9	2820.7

The abovementioned table as well as the graph show that, in case of new exploration there should be no hurdle in transmitting the natural gas to all around the country including the project location.

Moreover, the 6th nationwide gas transmission pipeline (IGAT 6) which is under construction aims at supplying natural gas to the provinces of Genaveh and Khuzestan by the amount of 110 MCMD. By the end of 2007 the physical progress of this project was 71.47% and is expected to be finished in the upcoming years. This additional 110 MCMD is again far beyond the need of the power plant (2.14 MCMD) and can provide natural gas for more than 48 power plants of similar size in the province of Bushehr.

In overall, based on what mentioned above the project in question is not depriving any other future user. Natural gas is sufficiently available at the time of investment and future projections and explorations clearly demonstrate this fact. Moreover, the vicinity to the one of the largest gas basins in the world as well as complicated and thorough gas pipelines network guarantees the use of natural gas for the whole year.

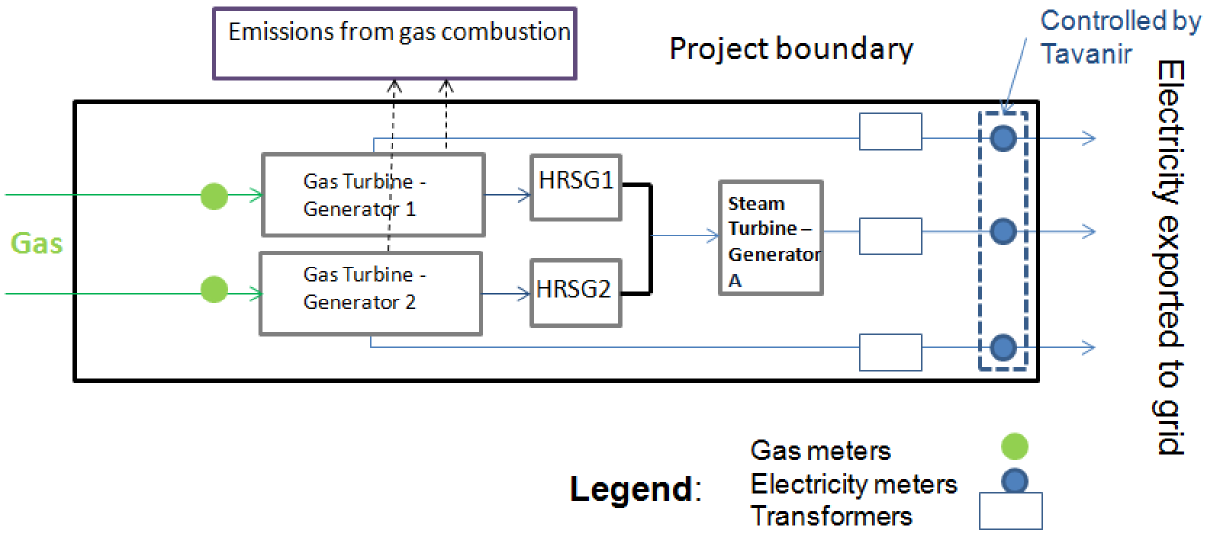
[33] Energy balance sheet 2007, transmission

B.3. Project boundary

Source		GHGs	Included?	Justification/Explanation
Baseline scenario	Power generation in baseline	CO_2	Yes	Main emission source
		CH_4	No	Excluded for simplification. This is conservative.
		N_2O	No	Excluded for simplification. This is conservative.
Project scenario	On-site fuel combustion due to the project activity	CO_2	Yes	Main emission source
		CH_4	No	Excluded for simplification
		N_2O	No	Excluded for simplification.

The spatial extent of the project boundary includes the project site and all power plants connected physically to the baseline grid.

<u>Flow diagram of the project:</u>



B.4. Establishment and description of baseline scenario

In line with the requirements of AM0029 Version 03, the baseline scenario is determined by the following steps:

1: Identify plausible baseline scenarios

The identification of alternative baseline scenarios should include all possible realistic and credible alternatives that provide outputs or services comparable with the proposed CDM project activity (including the proposed project activity without CDM benefits), i.e., all type of power plants that could be constructed as alternative to the project activity within the grid boundary (as defined in "Tool to calculate emission factor for an electricity system").

Alternatives to be analysed should include, inter alia:

- *The project activity not implemented as a CDM project;*
- *Power generation using natural gas, but technologies other than the project activity;*

- *Power generation technologies using energy sources other than natural gas;*
- *Import of electricity from connected grids, including the possibility of new interconnections.*

These alternatives need not consist solely of power plants of the same capacity, load factor and operational characteristics (i.e. several smaller plants, or the share of a larger plant may be a reasonable alternative to the project activity), however they should deliver similar services (e.g. peak vs. baseload power). Note further that the baseline scenario candidates identified may not be available to project participants, but could be other stakeholders within the grid boundary (e.g. other companies investing in power capacity expansions). Ensure that all relevant power plant technologies that have recently been constructed or are under construction or are being planned (e.g. documented in official power expansion plans) are included as plausible alternatives. A clear description of each baseline scenario alternative, including information on the technology, such as the efficiency and technical lifetime, shall be provided in the CDM-PDD.

The project participant may exclude baseline scenarios that are not in compliance with all applicable legal and regulatory requirements.

If one or more scenarios are excluded, an appropriate explanation and documentation to support the exclusion of such scenario shall be provided.

Based on this, a table with all plausible alternatives to the proposed project activity is prepared. This table includes all power plant technologies which have been constructed, are under construction or are being planned in Iran[34]. All alternatives which don't deliver similar services or are not in compliance with all applicable legal and regulatory requirements will be excluded.

The project activity not implemented as a CDM project

Description of Alternative	Similar outputs? Compliance with requirements?
The project activity (i.e greenfield combined cycle gas fired power plant) not implemented as a CDM project	Delivers base load electricity. Is in compliance with requirements. ⇨ Plausible but not financially attractive (see step 3)

Power generation using natural gas, but technologies other than the project activity;

Description of Alternative	Similar outputs? Compliance with requirements?
Open cycle Gas Turbine Technical lifetime 200,000 hours *Source: Tool to determine the remaining lifetime of equipment, Version 01* Efficiency up to 32.59% *Source: Genaveh Energy Conversion Agreement (Heat Rate 11,045 KJ/kWh)*	Delivers similar output as project activity.(Base load) Is in compliance with requirements. ⇨ Plausible

[34] No coal fired power plant has ever been constructed in Iran, nor are any planned. Therefore coal is excluded as a plausible baseline scenario.

Steam Plant (using residual fuel oil and natural gas) Technical lifetime: 30 years *Source: World Bank Iran Power Sector Note* Efficiency: up to 37.5% *Source: UNFCCC-Tool: Tool to calculate the emission factor for an electricity system*	Delivers similar output as project activity. It is not in compliance with requirements anymore because of the decision made by Iran Power Development Company (IPDC) in 2003[35]. Not plausible => excluded.

Power generation technologies using energy sources other than natural gas;

Description of Alternative	Similar outputs? Compliance with requirements?
Diesel Oil Power Plant Technical lifetime: 50,000 hours *Source: Tool to determine the remaining lifetime of equipment, Version 01* *Efficiency: 39%* *Source: UNFCCC-Tool: Tool to calculate the emission factor for an electricity system*	Based on the Tavanir report (http://www2.tavanir.org.ir/info/stat87/42htmll/14.htm) no diesel power plant has been built since 1992. The reason is that there has been a nationwide effort to expand the use of natural gas. Moreover, based on the same report in 2007, consumption of natural gas has the priority over the liquid fuels such as diesel as diesel power plants will have difficulties in handling the fuel, higher maintenance and repair costs for Iranian power sector (Source: CAR 11.Diesel_Tavanir). These all together, prevent investors or other stakeholders to build such power plants. Therefore, this alternative cannot be a part of the baseline scenario. Not plausible => excluded.
Nuclear Power Technical lifetime: 60 years Efficiency: 36% *Source: IEA Energy Technology Essentials – Nuclear power http://www.iea.org/techno/essentials 4.pdf*	This alternative is available only to Atomic Energy Organization of Iran (http://www.aeoi.org.ir/Portal/Home/), a 100% Government of the Islamic Republic of Iran owned company, whose capacity additions are driven by the Islamic Republic of Iran`s initiatives based on its long term strategic programs and not by the project activity. Hence, this option is not available for any of the stakeholders including the project activity. Therefore this alternative cannot be a part of the baseline scenario. Not plausible => excluded.
Large hydropower plant Technical lifetime (up to 100 years) *Source:*	This is not a plausible baseline scenario as it delivers peak-load power to the grid and not the base load power.[36]

[35] In a statement by Member of Management and Executive of Steam Projects to executive of CC plants projects at IPDC, it is mentioned that after commissioning of the steam plants in 2003, by focus on combined cycle plants and also liquidity and financial problems and heavy volume of operations, none of the steam plant projects have been executed. Moreover, the exiting report published by Tavanir at the time of investment decision (2007-2008) provides arguments in line with the aforementioned letter.

Source: CAR 11.Steam_Power_Plants_Iran and CAR11.Steam_power_plants_2007_2008_Tavanir_report

[36] http://www.aph.gov.au/binaries/library/pubs/rp/2008-09/09rp09.pdf

http://www.iea.org/papers/2010/Hydropower_Essentials.pdf Turbine Efficiency up to 95% (http://www.mpoweruk.com/hydro_power.htm) Average capacity factor: 44% (http://srren.ipcc-wg3.de/report/IPCC_SRREN_Ch05.pdf, page 441)	Is in compliance with requirements. Not plausible => excluded.
Wind Technical lifetime: 25-30 years *Source:* http://www.renewable-energy-sources.com/2009/11/10/technical-lifetime-of-wind-turbines/ Efficiency: 20- 40% Source: http://www.umass.edu/windenergy/publications/published/communityWindFactSheets/RERL_Fact_Sheet_2a_Capacity_Factor.pdf	Does not deliver comparable output as project activity, since wind farms are an intermittent source of power. Therefore wind farms cannot be used to displace base load capacity. Is in compliance with requirements. Not plausible => excluded.

Import of electricity from connected grids, including the possibility of new interconnections

<table>
<tr><th>Description of Alternative</th><th>Similar outputs? Compliance with requirements?</th></tr>
<tr><td>Import of electricity from connected grids, including the possibility of new interconnections.</td><td>Import of electricity from other grids is not realistic as most of the other grids themselves are facing shortages in meeting the energy demands and for those that do not have the shortage, the amounts that can be imported is too small due to lack of reasonable infrastructure and technically infeasibilities. Iran neighbours with the countries of Afghanistan, Pakistan, Iraq, Turkey, Armenia and Azerbaijan. Amongst them all as can be seen in the following table, Afghanistan, Turkey, Iraq and Azerbaijan faced continuous shortages on average in 2006-07(Source: based on CIA Fact Book):
<table>
<tr><th rowspan="2">Country</th><th colspan="3">2006</th><th colspan="3">2007</th><th rowspan="2">Average</th></tr>
<tr><th>Generation*</th><th>Consumption</th><th>Difference</th><th>Generation</th><th>Consumption</th><th>Difference</th></tr>
<tr><td>Afghanistan</td><td>0.91</td><td>1.04</td><td>-0.13</td><td>0.73</td><td>0.78</td><td>-0.05</td><td>-0.09</td></tr>
<tr><td>Iraq</td><td>31.7</td><td>33.3</td><td>-1.6</td><td>34.6</td><td>33.3</td><td>1.3</td><td>-0.15</td></tr>
<tr><td>Turkey</td><td>133.6</td><td>140.3</td><td>-6.7</td><td>143.3</td><td>140.3</td><td>3</td><td>-1.85</td></tr>
<tr><td>Azerbaijan</td><td>20</td><td>20.25</td><td>-0.25</td><td>20.35</td><td>20.57</td><td>-0.22</td><td>-0.23</td></tr>
</table>
* Amounts are in billion kWh
Having deep deficit of energy supply during peak demands of the years 2006 and 2007, Pakistan is not in a position to export electricity to Iran. Supply deficit during the peak times were -441 MW and -1457 MW in years 2006 and 2007 accordingly (Source: Pakistan_supply_deficit) . Excess supply of</td></tr>
</table>

	electricity in Armenia during the peak demand was too low in 2006 and 2007 for exporting to another grid[37]. This alternative does not deliver the same output comparable to the project activity due the high transmission cost. Not plausible => excluded.

Outcome of Step 1: List of plausible alternative scenarios to the project activity

Scenario	Title of Alternative
1	The project activity (i.e Greenfield combined cycle gas fired power plant with the capacity of 484 MW) not implemented as a CDM project
2	Open cycle Gas Turbine equivalent to the capacity of 484 MW

Step 2: Identify the economically most attractive baseline scenario alternative

The economically most attractive baseline scenario alternative is identified using investment analysis. Calculate a suitable financial indicator for all alternatives remaining after Step 1. Include all relevant costs (including, for example, the investment cost, fuel costs and operation and maintenance costs), and revenues (including subsidies/fiscal incentives[38], ODA, etc. where applicable), and, as appropriate, non-market costs and benefits in the case of public investors.

The investment analysis should be presented in a transparent manner and all the relevant assumptions should be provided in the CDM-PDD, so that a reader can reproduce the analysis and obtain the same results. Critical techno-economic parameters and assumptions (such as capital costs, fuel price projections, lifetimes, the load factor of the power plant and discount rate or cost of capital) should be clearly presented. Justify and/or cite assumptions in a manner that can be validated by the DOE. In calculating the financial indicator, the risks of the alternatives can be included through the cash flow pattern, subject to project specific expectations and assumptions (e.g. insurance premiums can be used in the calculation to reflect specific risk equivalents). Where assumptions, input data, and data sources for the investment analysis differ across the project activity and its alternatives, differences should be well substantiated. The CDM-PDD submitted for validation shall present a clear comparison of the financial indicator for all scenario alternatives. The baseline scenario alternative that has the best indicator (e.g. the highest IRR) can be pre-selected as the most plausible baseline scenario". Then a sensitivity analysis shall be performed for all alternatives. The range of the sensitivity analysis should cover, in a realistic way, the possible variations of all key parameters that are related to the analysis and that could change over the crediting period.

To determine the financially most attractive baseline scenario levelized investment costs for the three different scenarios are calculated. Levelized costs will be calculated according to the methodology developed by the International Energy Agency [39] according to the following formula:

$$EGC = \Sigma\,[(I_t + M_t + F_t)\,(1+r)^{-t}] \,/\, \Sigma\,[E_t\,(1+r)^{-t}]$$

With:

EGC: Average lifetime levelised electricity generation cost

[37] World_bank_report_AM

[38] Note the guidance by EB22 on national and/or sectoral policies and regulations.

[39] Projected Costs of Generating Electricity, International Energy Agency

It: Investment expenditures in the year t

Mt: Operations and maintenance expenditures in the year t

Ft: Fuel expenditures in the year t

Et: Electricity generation in the year t

r: Discount rate

Parameter (unit)	Value	Source
Characteristics of combined cycle plant		
Gross capacity CC power plant (MW)	484	Genaveh Feasibility Study
Average availability of CC power plant	91.64%	Genaveh Feasibility Study
Actual Nominal Capacity (MW)	423.24	Genaveh Feasibility Study
Investments costs		
International investment costs (EUR)	331,100,000	Genaveh Feasibility Study
Domestic investment costs (Rials)	0	Genaveh Feasibility Study
Total investment costs (million Rials)	3,873,193	Calculated
Operation and maintenance costs combined cycle		
Fixed O&M costs (Million Rials/year)	83,728	Genaveh Feasibility Study
Variable O&M costs (Rials/KWh)	24.66	Genaveh Feasibility Study
Fuel costs combined cycle		
Fuel costs combined cycle (Rials/Nm3)	0	Genaveh ECA pre-agreement
Timeline combined cycle		
Construction time (years)	3	Genaveh Feasibility Study
Technical lifetime of project (years)	25	Default value for lifetime of Steam Turbines, according to "Tool to determine the remaining lifetime of equipment" Version 01
Capacity, energy and fuel fees		
Capacity fee guaranteed price period (Rial per KWh)	185.57	Genaveh Feasibility Study
Generation Fee guaranteed price period (Rial per KWh)	20.62	Genaveh Feasibility Study
Percentage of the electricity delivered guranteed price period (%)	100%	Conservative value
Switch from guaranteed to market price for electricity after x months	60	Genaveh Feasibility Study
Market price of electricty year 1387/09 (Investment decision date) (Rial/kWh)	177.7	Iran Grid Management Company, Source: IRR_IGMC_electricty_prices, page 4
Proportion of capacity fee out of overall electricity price (after 5 years guaranteed period)	52%	Iran_grid_management_confirmation, Average until week 40
Proportion of energy fee out of overall electricity price (after 5 years guaranteed period)	48%	Iran_grid_management_confirmation, Average until week 40
Capacity fee (Rial per KWh) from year 6 onward	92.38	Calculation
Energy fee (Rial per kWh) from year 6 onward	85.27	Calculation
Electricity market price inflation rate from year 6 onward	5.36%	Iran Grid Management Company; see inflation tab
Percentage of the electricity delivered free market period (%)	100%	Conservative value
Economic indicators		
Inflation adjustment during guaranteed price period	12.17%	President Deputy Strategic Planning and Control and Central Bank of Iran, see "Inflation_data" for calculation
Exchange rate at date of investment decision (Rials/EUR) (Average of past six years)	11698	CBI, see inflation tab
Pre-tax nominal project IRR benchmark (%) or discount factor	25%	Ministry of Energy, "Benchmark_Confirmation"
Rial/EUR- Exchange rate depreciation (Average of past five years)	7.14%	CBI, see inflation tab

Characteristics of open cycle plant		
Gross capacity open power plant (MW)	477	World Bank report
Average availability of open power plant	83%	World Bank report
Actual Nominal Capacity (MW)	401.7	World Bank report
Investments costs		
Investment costs (USD)	141,390,000	World Bank report
Domestic investment costs (Rials)	0	World Bank report
Total investment costs (million Rials)	1,247,349	Calculated
Operation and maintenance costs open cycle		
Fixed O&M costs (Million USD/year)	0.48	World Bank report
Variable O&M costs + Fuel Variable costs (USD/kWh)	0.00152	World Bank report
Fuel costs open cycle		
Fuel costs open cycle (Rials/Nm3)	0	
Timeline open cycle		
Construction time (years)	3	Confirmation from Tavanir
Technical lifetime of project (hours)	200000	Default value for lifetime of Gas Turbines, according to "Tool to determine the remaining lifetime of equipment" Version 01
Economic indicators		
Exchange rate at date of investment decision (Rials/USD)	8822	CBI, see inflation tab
Rial/USD- Exchange rate depreciation (Average of past five years)	4.23%	CBI, see inflation tab

Based on these assumptions we get the following results for the levelized electricity generation costs:

		Combined Cycle	Gas Turbine
Scenario 0 - Base case		438.48	162.22

The levelized electricity generation costs calculation clearly shows that open cycle gas power plants have the lowest unit costs per kWh generated. We will now check whether the outcome of this result is robust to reasonable variations in the critical assumptions.

A sensitivity analysis shall be performed for all alternatives, to confirm that the conclusion regarding the financial attractiveness is robust to reasonable variations in the critical assumptions (e.g. fuel prices and the load factor). The investment analysis provides a valid argument in selecting the baseline scenario only if it consistently supports (for a realistic range of assumptions) the conclusion that the pre-selected baseline scenario is likely to remain the most economically and/or financially attractive.

For the sensitivity analysis, the following parameters are varied by +/- 10%:

- Investment expenditures
- Operation and maintenance costs
- Electricity generation
- Discount rate
- Exchange rates

The outcome of the sensitivity analysis is shown below

		Combined Cycle	Gas Turbine
Scenario 0 - Base case		438.48	162.22
Scenario 1 - Investment			
	10.00%	477.40	162.22
	-10.00%	399.56	162.22
	-70.99%	162.22	162.22
Scenario 2- O&M costs			
	10.00%	443.41	162.22
	-10.00%	433.55	162.22
	-100.00%	389.18	162.22
Scenario 3 - Availability			
	9.12%	403.88	162.22
	-10.00%	484.46	162.22
	9.12%	403.88	162.22
Scenario 4- Discount rate			
	10.00%	485.24	162.22
	-10.00%	393.89	162.22
	-75.98%	162.22	162.22
Scenario 5 - Exchange rate fluctuation			
	10.00%	440.81	162.22
	-10.00%	436.16	162.22
	-2299.48%	162.22	162.22

(Rial/kWh)			
		Gas Turbine	Combined Cycle
Scenario 0 - Base case		162.22	438.48
Scenario 1 - Investment			
	10.00%	176.45	438.48
	-10.00%	147.99	438.48
	194.17%	438.48	438.48
Scenario 2- O&M costs			
	10.00%	164.21	438.48
	-10.00%	160.22	438.48
	1385.36%	438.48	438.48
Scenario 3 - Availability			
	10.00%	149.11	438.48
	-10.00%	178.24	438.48
	-65.70%	438.48	438.48
Scenario 4- Discount rate			
	10.00%	179.11	438.48
	-10.00%	146.18	438.48
	127.75%	438.48	438.48
Scenario 5 - Exchange rate fluctuation			
	10.00%	163.34	438.48
	-10.00%	161.12	438.48
	670.82%	438.48	438.48

If sensitivity analysis confirms the result, then select the most economically attractive alternative as the most plausible baseline scenario. In case the sensitivity analysis is not fully conclusive, select the baseline scenario alternative with the lowest emission rate among the alternatives that are the most financially and/or economically attractive.

As can be seen above, the sensitivity analysis is fully conclusive as in all scenarios the open cycle gas turbine is clearly the lowest cost option. Therefore we can conclude that open cycle gas turbine is the most plausible baseline scenario.

Outcome of baseline determination: open cycle gas turbine is the most plausible baseline scenario

B.5. Demonstration of additionality

In this section an additionality assessment of the project activity (i.e Greenfield combined cycle gas fired power plant) not implemented as a CDM project will be conducted. In line with the requirements of the methodology AM0029 Version 3, the "Tool for the demonstration and assessment of additionality" Version 07.0.0 will be used.

Additionality

The assessment of additionality comprises the following steps:

Step 1: Benchmark investment analysis

Demonstrate that that the proposed CDM project activity is unlikely to be financially attractive by applying Sub-steps 2b (Option III: Apply benchmark analysis), Sub-step 2c (Calculation and comparison of financial indicators), and 2d (Sensitivity Analysis) of the latest version of the "Tool for demonstration assessment and of additionality" agreed by the CDM Executive Board.

Sub-step 2b: Option III. Apply benchmark analysis

The IRR is chosen as the suitable financial indicator to perform the benchmark analysis. 25% is the applicable benchmark for a pre-tax project IRR analysis of investments in the electricity sector in Iran, as confirmed by the Ministry of Energy of Iran.

Sub-step 2c: Calculation and comparison of financial indicators:

The assumptions used in the IRR calculation are specified as above:

The result of the financial analysis is provided below.

	Pre-tax project IRR	Benchmark
Base case	11.02%	25%

As can be seen, the proposed project activity not implemented as a CDM project is clearly not financially attractive.

Sub-step 2d: Sensitivity analysis:

A sensitivity analysis is conducted to see if this result is robust to reasonable variations in the underlying assumptions. In line with the Guidance on the Assessment of Investment Analysis (version 5), all parameters which constitute either more than 20% of either total project cost or total project revenues are subjected to reasonable variation of either +10% or -10%.

The following parameters constitute more than 20% of either total project cost or total project revenues:

		% of total costs/revenues
Costs	Investment Costs	21%
	Maintenance Costs	79%
Revenues	Electricity tariff	62%
	Capacity fee	38%

In addition, operating hours and inflation rate were also subjected to the same sensitivity analysis, since they have an indirect impact on either total project costs or revenues which exceeds 20%. The sensitivity analysis also checks which variation in the parameters is necessary to reach the benchmark of 25%.

The results of the sensitivity analysis are shown below:

		Pre-tax project IRR	Benchmark
	Base case	11.02%	25%
	Scenario 1 - Investment	**Pre-tax project IRR**	**Benchmark**
	10%	9.44%	25%
	-10%	12.89%	25%
	-48.20%	24.93%	25%
	Scenario 2 - O&M costs		
	10%	8.03%	25%
	-10%	11.85%	25%
*	-100.00%	20.66%	25%
	Scenario 3 - Availability		
	9.12%	13.19%	25%
	-10%	8.32%	25%
**	9.12%	13.19%	25%
	Scenario 4 - Electricity tariff		
	10%	14.02%	25%
	-10%	7.21%	25%
	60.51%	24.98%	25%
	Scenario 5 - Inflation rates		
	10%	10.76%	25%
	-10%	11.04%	25%
***	10.00%	10.76%	25%
	Scenario 6 - Exchange rate fluctuations		
	10%	10.91%	25%
	-10%	11.13%	25%
	-946.83%	24.96%	25%
*	Minimum amount that O&M costs can take.		
**	When power plant operates 100%.		
***	Inlfation rates variations does lead IRR to cross the benchmark.		

The sensitivity analysis confirms the outcome of the benchmark analysis. Only an improbably large variation of the parameters will lead to the project reaching the benchmark. This clearly shows that the project activity (i.e Greenfield combined cycle gas fired power plant) not implemented as a CDM project is not financially attractive.

Outcome of Step 1 Benchmark investment analysis: the project activity (i.e Greenfield combined cycle gas fired power plant) not implemented as a CDM project is not financially attractive and therefore satisfies the requirements of Step 1.

Step 2: Common practice analysis

Demonstrate that the project activity is not common practice in the relevant country and sector by applying Step 4 (common practice Analysis) of the latest version of the "Tool for demonstration assessment and of the additionality" agreed by the CDM Executive Board.

The "Tool for demonstration assessment and of additionality" Version 07.0.0 refers to the "Guidelines on common practice" Version 02.0 that requires the following steps:

Stepwise approach for common practice:

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

The proposed project activity has a capacity of 484 MW. Therefore the applicable capacity range is equal to 242 MW – 726 MW.

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;

(a) The projects are located in the applicable geographical area: Islamic Republic of Iran, since Iran has a unique regulatory environment based on extremely low fossil fuel and electricity prices while simultaneously pursuing a number of market based reforms[40].

(b) The projects apply the same measures as the proposed project activity;

(b) Four types of measures are currently covered in the framework:

(i) Fuel and feedstock switch

(ii) Switch of technology with or without change of energy source including energy efficiency improvement as well as use of renewable energies

(iii) Methane destruction

(iv) Methane formation avoidance

Item (ii) applies for the purpose of project activity. Since oil, steam or open cycle gas turbines are fall under measure ii (switch of technology). And hydro power plants, being renewable energy power plants, are considered to be of measure ii as combined cycle power plants in line with the above definition.

(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;
The project uses natural gas as the energy source/fuel. Oil, steam or open cycle gas turbines are using same fuels. And hydro power plants, being renewable energy power plants, are not fall under switch of technology.

(d) The plants in which the projects are implemented produce goods or services within the comparable quality, properties and applications areas (e.g. clinker) as the proposed project plan
The projects offer electricity generation.

(e) The capacity or output of the projects is within the applicable capacity or output range calculated in Step 1;
The output range is +/-50% of the overall capacity of project scenario (between 242 MW and 726 MW).

(f) The project is 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[41].
The project is started commercial operation before the start date of proposed project activity.
Moreover, items (b), (c), (d), (e) and (f) have been clarified in the following table.

Start of project activity: June 8 2009

[40] World Bank Iran Power Sector Note (2007), p.2

[41] While identifying similar projects, project participants may also use publicly available information, for example from government departments, industry associations, international associations on the market penetration of different technologies, etc.

List of all power plants in Iran with an installed capacity between 242 MW and 726 MW which were commissioned before June 8 2009:

Number	Name of power plant	Commissioned capacity before June 8 2009 (MW)	Technology	Owner	Commissioning	Fuel	Source	Different technology[42]? If yes, indication of category	Same measure?	Same energy source/fuel and feedstock?	Produce good/service with comparable quality?	Registered CDM, submitted for registration or validation phase?
1	Besat	247.5	Steam Power Plant	Ministry of Energy (MOE)	1967-1969	Diesel, fuel oil and natural gas	http://www2.tavanir.org.ir/info/stat89/sanatlhtml/Links/j13-1/main.htm	Yes, (iv) legal regulations and	Yes	Yes	Yes	No
2	Shahid Montazer Ghaem	625.88	Steam Power Plant	Ministry of Energy (MOE)	1971-1973	Diesel, fuel oil and natural gas	http://www2.tavanir.org.ir/info/stat89/sanatlhtml/Links/j13-1/main.htm	Yes, (iv) legal regulations and	Yes	Yes	Yes	No
3	Toos	600	Steam Power Plant	Ministry of Energy (MOE)	1985-1987	Diesel, fuel oil and natural gas	http://www2.tavanir.org.ir/info/stat89/sanatlhtml/Links/j13-1/main.htm	Yes, (iv) legal regulations and	Yes	Yes	Yes	No
4	Bistoon	640	Steam power plant	Ministry of Energy (MOE)	1994	Diesel, fuel oil and natural gas	http://www2.tavanir.org.ir/info/stat89/sanatlhtml/Links/j13-1/main.htm	Yes, (iv) legal regulation and	Yes	Yes	Yes	No
5	Iran Shahr	256	Steam power plant	Ministry of Energy (MOE)	95-92-03-03	Diesel and fuel oil	http://www2.tavanir.org.ir/info/stat89/sanatlhtml/Links/j13-1/main.htm	Yes, (iv) legal regulations and	Yes	Yes	Yes	No

[42] See step 4 below

6	Sahand	650	Steam power plant	Ministry of Energy (MOE)	2004-2005	Diesel, fuel oil and natural gas	http://www2.tavanir.org.ir/info/stat89/sanatlhtml/Links/j13-1/main.htm	Yes, (iv) legal regulations,	Yes	Yes	Yes	No
7	Abadan	493	Open cycle Power Plant	Ministry of Energy (MOE)	2002-2003	Diesel and natural gas	http://www2.tavanir.org.ir/info/stat89/sanatlhtml/Links/j13-1/main.htm	Yes, (iv) legal regulations and (v) unit cost of output	Yes	Yes	Yes	No
8	Sanandaj	636	Open cycle Power Plant	Ministry of Energy (MOE)	2005-2006	Diesel and natural gas	http://www2.tavanir.org.ir/info/stat89/sanatlhtml/Links/j13-2/main.htm	Yes, (v) unit cost of output	Yes	Yes	Yes	No
9	Chabahar	318	Open cycle Power Plant	Ministry of Energy (MOE)	2008-2009	Diesel	http://www2.tavanir.org.ir/info/stat89/sanatlhtml/Links/j13-2/main.htm	Yes, (v) unit cost of output	Yes	No	Yes	No
10	Shahid Kaveh	318	Open cycle Power Plant	Ministry of Energy (MOE)	2008-2009	Natural Gas	http://www2.tavanir.org.ir/info/stat89/sanatlhtml/Links/j13-2/main.htm The last two units commissioned only after June 8 2009 and are therefore excluded.	Yes, (v) unit cost of output	Yes	Yes	Yes	No

							See: http://www2.tavanir.org.ir/info/stat89/44htmll/20-2.htm					
11	Qom Combined Cycle	714	Combined Cycle Power Plant	Ministry of Energy (MOE)	1993-1997-1998	Diesel and natural gas	http://www2.tavanir.org.ir/info/stat89/sanatlhtml/Links/j13-2/main.htm	Yes, (iv) legal regulations	Yes	Yes	Yes	No
12	Shariati Combined Cycle	346.8	Combined Cycle Power Plant	Ministry of Energy (MOE)	1994-2003	Diesel and natural gas	http://www2.tavanir.org.ir/info/stat89/sanatlhtml/Links/j13-2/main.htm	Yes, (iv) legal regulations	Yes	Yes	Yes	No
13	Khuy Combined Cycle	349.3	Combined Cycle Power Plant	Ministry of Energy (MOE)	1997-2002	Diesel and natural gas	http://www2.tavanir.org.ir/info/stat89/sanatlhtml/Links/j13-2/main.htm	Yes, (iv) legal regulations	Yes	Yes	Yes	No
14	Shahid Salimi Combined Cycle	435	Combined Cycle Power Plant	Ministry of Energy (MOE)	1990-2006	Diesel and natural gas	http://www2.tavanir.org.ir/info/stat89/sanatlhtml/Links/j13-2/main.htm	Yes, (iv) legal regulations	Yes	Yes	Yes	No
15	Dez Dam	520	Hydro Power Plant	Ministry of Energy (MOE)	1962-2001	-	http://www2.tavanir.org.ir/info/stat89/sanatlhtml/Links/j13-2/main.htm	Yes, (i) Energy source/fuel, (iv) legal regulations, (v) unit cost of output	Yes	No	Yes	No
16	Karkhe Dam	399.9	Hydro Power	Ministry of	2002-2003	-	http://www2.tavanir.org.	Yes, (i) energy	Yes	No	Yes	No

			Plant	Energy (MOE)			ir/info/stat89/sanatlhtml/Links/j13-2/main.htm	source/fuel, (iv) legal regulations and (v) other technologies				
17	Zargan	290	Steam Power Plant	Private	1975-1992	Natural Gas	http://www2.tavanir.org.ir/info/stat89/sanatlhtml/Links/j13-3/main.htm	Yes, (iv) legal regulations, (iv) promotional policies	Yes	Yes	Yes	No
18	Khoram shahr	324	Open cycle	Private	2008-2009	Diesel and natural gas	http://www2.tavanir.org.ir/info/stat89/sanatlhtml/Links/j13-4/main.htm The last unit commissioned only on July 11 2009 and is therefore excluded. See: http://www2.tavanir.org.ir/info/stat89/44htmll/20-2.htm	Yes, (iv) promotional policies, (v) unit cost of output	Yes	Yes	Yes	No

Outcome of step 2:

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

(b) *The projects apply the same measures as the proposed project activity;*
Items 1 to 18 apply the same measure (Switch of technology with or without change of energy source including energy efficiency improvement as well as use of renewable energies.)

(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;*
The project uses natural gas as the energy source/fuel. Therefore, 16 power plants use the same energy/source fuel and feedstock (all listed projects except items 15 -16, i.e. Hydro power plants)

(d) *The plants in which the projects are implemented produce goods or services within the comparable quality, properties and applications areas (e.g. clinker) as the proposed project plan*
The projects offer electricity generation.

(e) *The capacity or output of the projects is within the applicable capacity or output range calculated in Step 1;*
The output range is +/-50% of the overall capacity of project scenario (between 242 MW and 726MW). All the projects are within this range.

(f) *The project is 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*[43]*.*

The projects started commercially operating before the start date of project activity.

Outcome: Items 1-18 of the power plant lists fulfill the requirements of step 2.

Step 3: Within the projects identified in Step 2, identify those that are neither registered CDM project activities, project activities for registration, note project activities undergoing validation. Note their number $N_{all.}$
There was no activity of CDM in any type (registered, registration or validation) in Iran in 2008 or before[44]. Hence:
Total number of power plants: $N_{all.}= 18$

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

As per guideline on common practice version 2.0 *Different technologies are technologies that deliver the same output and differ by at least one of the following:*

(i) *Energy source/fuel: hydro power plants* use a different fuel and the proposed project activity

(iv) *Investment climate on the date of investment decision, eg. Promotional policies: private power plants* don't pay for their fuel (natural gas or gas/diesel oil)[45]

[43] While identifying similar projects, project participants may also use publicly available information, for example from government departments, industry associations, international associations on the market penetration of different technologies, etc.

[44] Source: CMD Pipline. http://cdmpipeline.org/publications/CDMStatesAndProvinces.xlsx

(iv) *Investment climate on the date of investment decision, eg. Legal regulations:* project start prior to the creation of the power pool in Iran in 2005[46]

(v) *Other* features, inter alia nature of the investment, eg. Unit cost of output (differ by at least 20%): the World Bank Iran Power Sector Note p. 70 gives the total levelized cost for several power plant technologies in Iran:

Technology	Total levelized electricity generation cost (Rial/kWh)	Within range +/-20% of levelized costs combined cycle?
Combined Cycle gas turbines	438.48	Yes
Gas Turbine	162.22	No

Therefore all items can be considered as a different technology.
Applying the above mentioned criteria, all the plants identified in Step 2 apply technologies different than the technology applied in the proposed project activity.
Different technologies: N_{diff} = 18

Step 4: Calculate factor $F=1-N_{diff}/N_{all}$ representing the share of plants using technology similar to the technology used in the proposed project activity in all plants that deliver the same output or capacity as the proposed project activity.
$F=1-N_{diff}/N_{all} = 1 – 18 /18 = 1 – 1 = 0$

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.
F = 0 and $N_{all}-N_{diff}$ = 18 – 18 = 0

Therefore the proposed project activity is **not** a "common practice" within a sector in the applicable geographical area.

Step 3: Impact of CDM registration

The latest "Tool for the demonstration and assessment of additionality" Version 07.0.0, does not contain step 5. However financial benefits of CDM are shown below.

CER revenue		
CER in tCO2e/year	702849	CER sheet (for 10 years)
CER revenue (1 Euro/CER)	5	Assumed
Pre Tax Project IRR	11.84%	

If all 3 steps are satisfied, then the project is considered additional.

Since these three are satisfied the project activity is considered additional.

Since the starting date of the project activity is before the date of validation, evidence is provided that the incentive from the CDM was seriously considered in the decision to proceed with the project activity. On January 28 2009 MAPNA sent a prior consideration letter to the Designated National Authority (DNA) of Iran for the proposed CDM project activity. The starting date of the CDM project activity is 08/06/2009, ie the date when the Engineering, Procurement and Construction Contract was signed. The prior consideration letter was sent to the Iranian DNA within

[45] See Document 21: World Bank Iran Power Sector Note, p. 50

[46] See Document 64: Electricity Mkt Confirmation

6 months of the project start date, which is in line with the applicable Guidance on the Demonstration and Assessment of Prior Consideration of the CDM, Version 1[47].
In addition, a timeline is prepared which shows that the CDM was crucially important when taking the decision to implement the project:

Date	Development to combined cycle project	Activities taken to achieve CDM registration	Evidence
17 March 2007	Pre-ECA contract		Pre-ECA
28 May 2008		Exchanging letters about the benefits of CDM	Exchanges between PP and Energy Changes
3 January 2009	Feasibility study report	Feasibility study report evaluating the impact of the CDM on the project.	Feasibility Study Report
24 January 2009	Board decision on implementing project under CDM procedure ("Investment start date")	Board decision on implementing project under CDM procedure ("Investment start date")	Board decision
28 January 2009		Prior consideration sent to the local DNA	Prior consideration
3 March 2009		Draft ERPA	Exchanges between PP and Energy changes
08 June 2009 (Start date)	Pre-EPC contract		Pre-EPC contract
25 July 2009	Land handover		Land handover agreement
20 December 2009	Equipment Purchase Agreement		EPC
March 6 2010		Exchanging letters about the CER market, risks and opportunities for the project.	Exchanges between PP and consultants
November 21 2010		Communications made to discuss the financial situations of the contract	Exchanges between PP and consultants
November 22 2010		Initial acceptance of emission reduction contract terms given by PP	Exchanges between PP and consultants
February 24 2011		Communications were made about the present situation of the projects	Exchanges between consultant's

[47] Version 2 requiring all notifications to be sent to both the host country DNA and the UNFCCC secretariat in Bonn was only adopted on July 19 2009 at EB 48.

March 16 2011		Negotiations between Swiss Carbon Assets Ltd. And PP starts.	Exchanges between PP and consultants
2 May 2011		Contract signed between SQS (Swiss Association for Quality and Management System) and Swiss Carbon Assets Ltd. which obliges SQS to follow up the request based on the draft PDD that is provided for an Iranian project by SP.	Contract exchanged
2 May 2011		Draft PDD that was sent to UNFCCC for an Iranian project.	Communication with SQS and Swiss Carbon Assets
2 May 2011	Energy Conversion Agreement		Energy conversion agreement
5 May 2011		Swiss Carbon Assets exchanges contract with **SQS** (Swiss Association for Quality and Management System) for uploading revisions on AM0029 methodology.	Contract signed
10 July 2011		Emission Reduction Purchase Agreement (ERPA) signed with Swiss Carbon Assets Ltd.	ERPA
27 July 2011		Stakeholder consultation meeting	Stakeholder consultation report
19 August 2011		The request is reviewed by UNFCCC.	Response of UNFCCC
03 July 2012		Notification of progress listed on UNFCCC	Notification of Progress

B.6. Emission reductions

B.6.1. Explanation of methodological choices

In accordance with AM0029 version 3, the emission reductions are calculated as follows:

Project emissions

The project activity is on-site combustion of natural gas to generate electricity. The CO_2 emissions from electricity generation (PE_y) are calculated as follows:

$$PE_y = \sum_f FC_{f,y} * COEF_{f,y} \quad \textbf{(1)}$$

Where:

$FC_{f,y}$: = Is the total volume of natural gas or other fuel ‘f’ combusted in the project plant including in HRSG unit or other fuel (m3 or similar) in year(s) y

$COEF_{f,y}$: = Is the CO_2 emission coefficient (tCO_2/m^3 or similar) in year(s) for each fuel and is obtained as:

$COEF_{f,y} = \Sigma NCV_{f,y} * EF_{CO2,f,y} * OXID_f$ **(1a)**

Where:

$NCV_{f,y}$: = Is the net calorific value (energy content) per volume unit of natural gas or other fuel in year *y* (GJ/m^3) as determined from the fuel supplier, wherever possible, otherwise from local or national data

$EF_{CO2,f,y}$: = Is the CO_2 emission factor per unit of energy of natural gas or other fuel in year *y* (tCO_2/GJ) as determined from the fuel supplier, wherever possible, otherwise from local or national data

$OXID_f$: = Is the oxidation factor of natural gas

For start-up fuels, IPCC default calorific values and CO_2 emission factors are acceptable, if local or national estimates are unavailable.

Baseline emissions

Baseline emissions are calculated by multiplying the electricity generated in the project plant ($EG_{PJ,y}$) with a baseline CO_2 emission factor ($EF_{BL,CO2,y}$), as follows:

$$BE_y = EG_{PJ,y} \cdot EF_{BL,CO2,y} \quad \textbf{(2)}$$

For construction of large new power capacity additions under the CDM, there is a considerable uncertainty relating to which type of other power generation is substituted by the power generation of the project plant. As a result of the project, the construction of an alternative power generation technology(s) could be avoided, or the construction of a series of other power plants could simply be delayed. Furthermore if the project were installed sooner than these other projects might have been constructed, its near-term impact could be largely to reduce electricity generation in existing plants. This depends on many factors and assumptions (e.g. whether there is a supply deficit) that are difficult to determine and that change over time. In order to address this uncertainty in a conservative manner, project participants shall use for $EF_{BL,CO2,y}$ the lowest emission factor among the following three options:

For the first crediting period:

Option 1 The build margin, calculated according to “Tool to calculate emission factor for an electricity system”; and

Option 2 The combined margin, calculated according to “Tool to calculate emission factor for an electricity system”, using a 50/50 OM/BM weight;

Option 3 The emission factor of the technology (and fuel) identified as the most likely baseline scenario under “Identification of the baseline scenario” above, and calculated as follows:

$$EF_{BL,CO2}(tco2/Mwh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6GJ/MWh \quad \textbf{(3)}$$

Where:

$COEF_{BL}$: = The fuel emission coefficient (tCO2e/GJ), based on national average fuel data, if available, otherwise IPCC defaults can be used. If several fuels are used in the most likely baseline scenario then the fuel emission coefficient of the least

		carbon intensive fuel shall be used.
η_{BL} :	=	The energy efficiency of the technology, as estimated in the baseline scenario analysis above

This determination will be made once at the validation stage based on an ex ante assessment, once again at the start of each subsequent crediting period (if applicable). If either option 1 (BM) or option 2 (CM) are selected, they will be estimated ex post, as described in "Tool to calculate emission factor for an electricity system".

Calculating Option 1 & Option 2:

Version 4.0 of the "Tool to calculate the emission factor for an electricity system" is used for calculating the build margin (Option 1) or the combined margin (Option 2).

Step 1: Identify the relevant electricity systems

For determining the electricity emission factors, a project electricity system is defined by the spatial extent of the power plants that are physically connected through transmission and distribution lines to the project activity (e.g. the renewable power plant location or the consumers where electricity is being saved) and that can be dispatched without significant transmission constraints.

The relevant electricity system is the electricity grid of the Islamic Republic of Iran.

Justification:

There are only very limited power import and exports from Iran to neighbouring countries[48].

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

Project participants may choose between the following two options to calculate the operating margin and build margin emission factor:

Option I: Only grid power plants are included in the calculation.

Option II: Both grid power plants and off-grid power plants are included in the calculation.

Option I is chosen

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

The calculation of the operating margin emission factor (EFgrid,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.

Simple OM was chosen.

Justification:

[48] For data on electricity imports and exports see: http://www2.tavanir.org.ir/info/stat88/43htmll/50-1.htm

Low-cost/must-run resources constitute less than 50% of the total grid generation

Net Power Generation (GWh)													
	Fossil fuel based							Low-cost/must-run			SHARE [%]		
Year	Steam		Gas Turbine		C.C	Diesel	TOTAL	Hydro	Wind Energy	TOTAL	Fossil fuel based	Low cost /must run	
	MOE	non-MOE	MOE	non-MOE	MOE	MOE		MOE	MOE				
	A	B	C	D	E	F	G=Sum(A:F)	H	I	J=H+I	K=G/(G+J)	L=J/(G+J)	
2007	84850	3084	26788	10187	52941	210	178060	17877	141	18018	**90.81**	**9.19**	
2008	87678	2974	36289	17883	56023	190	201037	4689	196	4885	**97.63**	**2.37**	
2009	86000	3281	31416	21548	63114	116	205475	7149	228	7377	**96.53**	**3.47**	
2010	84181	3472	33425	24514	69542	119	215253	9448	211	9659	**95.71**	**4.29**	
2011	86243	3115	30180	28077	71389	58	219062	11986	574	12560	**94.58**	**5.42**	
										Average	**95.05**	**4.95**	**< 50%**

Source: CM_Margin_2009_2011 excel sheet, tab "STEP 3 Select Meth OM"

Two options are available:

- Ex-ante option: the emission factor is determined once at the validation stage
- Ex post option: the emission factor is updated annually during monitoring

The ex ante option is chosen.

Justification:

3-year generation-weighted averages based on the most recent data was used.

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

The simple OM emission factor 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:

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.

The project participant choose (a) Simple OM and Option B Calculation based on total fuel consumption and electricity generation of the system.

Justification

(a) The necessary data for Option A is not available; and

(b) Only nuclear and renewable power generation are considered as low-cost/must-run power sources and the quantity of electricity supplied to the grid by these sources is known; and

(c) Off-grid power plants are not included in the calculation (i.e., if Option I has been chosen in Step 2).

Option B- Calculation based on total fuel consumption and electricity generation of the system

Under this option, the simple OM emission factor is calculated based on the net electricity supplied to the grid by all power plants serving the system, not including low-cost/must-run power plants/units, and based on the fuel type(s) and total fuel consumption of the project electricity system, as follows:

$$EF_{grid,OMsimple,y} = \frac{\sum_i \left(FC_{i,y} \times NCV_{i,y} \times EF_{CO2,i,y}\right)}{EG_y}$$

Where:

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

$FC_{i,y}$ = Amount of fuel type i consumed in the project electricity system in year y (mass or volume unit)

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

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

EG_y = Net electricity generated and delivered to the grid by all power sources serving the system, not including low-cost/must-run power plants/units, in year y (MWh)

i = All fuel types combusted in power sources in the project electricity system in year y

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

Step 5: Identify the group of power units to be included in the build margin

The sample group of power units m used to calculate the build margin consists of either:

(a) The set of five power units that have been built most recently ;or

(b) The set of power capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently.

Project participants should use the set of power units that comprises the larger annual generation.

The project participants used approach (b).

<u>EGy Net quantity of electricity generated and delivered to the grid by power plant 2011 by:</u>

a) The set of five power units that have been built most recently: 611,602 MW
b) The set of power capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently: 47,902,644 MWh

<u>Source: CM_Margin_2009_2011 excel sheet, tab “STEP 5-1 BM calculation”</u>

<u>Justification:</u>

Approach (b) comprises the larger annual generation in 2011.

The sample group of power units *m* used to calculate the build margin is based on data provided by the Ministry of Electricity and Renewable Energy. The Power plants registered as CDM project activities were excluded from the sample group *m*.

Two options for data vintages are available:

- Option 1: calculation ex ante based on the most recent information available
- Option 2: annual updating based on the latest available information

Option 1: ex ante calculation was chosen

Step 6: Calculate the build margin emission factor

The build margin emissions factor is the generation-weighted average emission factor (tCO2/MWh) of all power units m during the most recent year y for which power generation data is available, calculated as follows:

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

Where:

$EF_{grid,BM,y}$ *= Build 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)*

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

m = Power units included in the build margin

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

Step 7: Calculate the combined margin emissions factor

The combined margin emissions factor is calculated as follows

$EF_{grid,CM,y}=EF_{grid,OM,y} \text{ x } w_{om}+EF_{grid,BM,y} \text{ x } w_{BM}$

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 (%)*

Since the proposed project activity is no wind or solar power generation project, the default values w_{OM} = 0.5 and w_{BM} = 0.5 are used for the first crediting period.

The minimum of the three emission factors (Option 1, Option 2 or Option 3) shall be used.

$$EF_{BL,CO2,y} = MIN(EF_{BL,CO2,Option1}, EF_{BL,CO2,Option2}, EF_{BL,CO2,Option3}) \quad \textbf{(4)}$$

Leakage

Leakage may result from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary. This includes mainly fugitive CH_4 emissions and CO_2 emissions from associated fuel combustion and flaring. In this methodology, the following leakage emission sources shall be considered:[49]

- *Fugitive CH_4 emissions associated with fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of natural gas used in the project plant and fossil fuels used in the grid in the absence of the project activity;*

[49] The EB is undertaking further work on the estimation of leakage emission sources in case of fuel switch project activities. This approach may be revised based on outcome of this work.

- *In the case LNG is used in the project plant: CO_2 emissions from fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression into a natural gas transmission or distribution system.*

Thus, leakage emissions are calculated as follows:

$$LE_y = LE_{CH4,y} + LE_{LNG,CO2,y} \quad \textbf{(5)}$$

Where:

LE_{y} :	=	*Leakage emissions during the year y in tCO_2e*
$LE_{CH4,y}$:	=	*Leakage emissions due to fugitive upstream CH_4 emissions in the year y in t CO_2e*
$LE_{LNG,CO2,y}$:	=	*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 during the year y in t CO_2e*

<u>Fugitive methane emissions</u>

For the purpose of estimating fugitive CH_4 emissions, project participants should multiply the quantity of natural gas consumed by the project in year y with an emission factor for fugitive CH_4 emissions ($EF_{NG,upstream,CH4}$) from natural gas consumption and subtract the emissions occurring from fossil fuels used in the absence of the project activity, as follows:

$$LE_{CH4,y} = \left[FC_y \cdot NCV_y \cdot EF_{NG,upstream,CH4} - EG_{PJ,y} \cdot EF_{BL,upstream,CH4}\right] \cdot GWP_{CH4} \quad \textbf{\textit{(6)}}$$

Where:

$LE_{CH4,y}$:	=	*Leakage emissions due to fugitive upstream CH_4 emissions in the year y in t CO_2e*
FC_{y} :	=	*Quantity of natural gas combusted in the project plant including in HRSG unti during the year y in m^3*
$NCV_{NG,y}$:	=	*Average net calorific value of the natural gas combusted during the year y in GJ/m^3*
$EF_{NG,upstream,CH4}$:	=	*Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, distribution, and, in the case of LNG, liquefaction, transportation, re-gasification and compression into a transmission or distribution system, in t CH_4 per GJ fuel supplied to final consumers*
$EG_{PJ,y}$:	=	*Electricity generation in the project plant during the year in MWh*
$EF_{BL,upstream,CH4}$:	=	*Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in t CH4 per MWh electricity generation in the project plant, as defined below*
GWP_{CH4} :	=	*Global warming potential of methane valid for the relevant commitment period*

The emission factor for upstream fugitive CH4 emissions occurring in the absence of the project activity (EFBL,upstream,CH4) should be calculated consistent with the baseline emission factor (EFBL,CO2) used in equation (4) above, as follows:

Option 1: Build Margin:

$$EF_{BL,upstream,CH4} = \frac{\sum_j FF_{j,k} \cdot EF_{k,upstream,CH4}}{\sum_j EG_j}$$

Option 2: Combined Margin:

$$EF_{BL,upstream,CH4} = 0.5 \cdot \frac{\sum_j FF_{j,k} \cdot EF_{k,upstream,CH4}}{\sum_j EG_j} + 0.5 \cdot \frac{\sum_i FF_{i,k} \cdot EF_{k,upstream,CH4}}{\sum_i EG_i}$$

Option 3: Baseline technology:

$$\mathrm{EF_{BL,upstream,CH4}} = \frac{\mathrm{EF_{k,upstream,CH4}}}{\eta_{\mathrm{BL}}} * 3.6\mathrm{GJ/MWh}$$

Where:

$EF_{BL,upstream,CH:4}$	=	*Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in t CH_4 per MWh electricity generation in the project plant*
j :	=	*Plants included in the build margin*
$FF_{j,k}$:	=	*Quantity of fuel type k (a coal or oil type) combusted in power plant j included in the build margin*
$EF_{k,upstream,CH4:}$	=	*Emission factor for upstream fugitive methane emissions from production of the fuel type k (a coal or oil type) in t CH_4 per MJ fuel produced*
EG_j :	=	*Electricity generation in the plant j included in the build margin in MWh/a*
i:	=	*Plants included in the operating margin*
$FF_{i,k}$:	=	*Quantity of fuel type k (a coal or oil type) combusted in power plant i included in the operating margin*
$EG_{i:}$	=	*Electricity generation in the plant i included in the operating margin in MWh/a*
η_{BL} :	=	*Energy efficiency of the most likely baseline technology*

If $EF_{BL,upstream,CH_4}$ *is determined based on the build margin or the combined margin, the calculation should be consistent with the calculation of CO2 emissions in the build margin and the combined margin, i.e. the same cohort of plants and data on fuel combustion and electricity generation should be used, and the values for FF and EG should be those already determined through the application of "Tool to calculate emission factor for an electricity system".*

Where reliable and accurate national data on fugitive CH_4 emissions associated with the production, and in case of natural gas, the transportation and distribution of the fuels is available, project participants should use this data to determine average emission factors by dividing the total quantity of CH_4 emissions by the quantity of fuel produced or supplied respectively.[50] *Where such data is not available, project participants should use the default values provided in Table 2 below.*

Default values in table 2 will be used.

<u>Justification</u>: no reliable and accurate national data on fugitive CH4 emissions associated with the production, and in case of natural gas, the transportation and distribution of the fuels is available.

Note that the emission factor for fugitive upstream emissions for natural gas ($EF_{NG,upstream,CH4}$) should include fugitive emissions from production, processing, transport and distribution of natural gas, as indicated in the Table 2 below. Where default values from this table are used, the natural gas emission factors for the location of the project activity should be used. The US/Canada values may be used in cases where it can be shown that the relevant system element (gas production and/or processing/transmission/ distribution) is predominantly of recent vintage and built and operated to international standards.

The values for other oil exporting countries/rest of world shall be used.

[50] 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.

Justification: Iran fits best into this category.

Since the fugitive upstream emissions for coal depends on the source (underground or surface mines), project participants should use the emission factor that corresponds to the predominant source (underground or surface) currently used by coal-based power plants in the region.

Note further that in case of coal the emission factor is provided based on a mass unit and needs to be converted in an energy unit, taking into account the net calorific value of the coal.

No coal is used in the proposed project activity.

Note that to the extent that upstream emissions occur in Annex I countries that have ratified the Kyoto Protocol, from 1 January 2008 onwards, these emissions should be excluded, if technically possible, in the leakage calculations.

Table 2: Default emission factors for fugitive CH_4 upstream emissions

Activity	Unit	Default emission factor	Reference for the underlying emission factor range in Volume 3 of the *1996 Revised IPCC Guidelines*
Coal			
Underground mining	t CH4 / kt coal	13.4	Equations 1 and 4, p. 1.105 and 1.110
Surface mining	t CH4 / kt coal	0.8	Equations 2 and 4, p.1.108 and 1.110
Oil			
Production	t CH4 / PJ	2.5	Tables 1-60 to 1-64, p. 1.129 - 1.131
Transport, refining and storage	t CH4 / PJ	1.6	Tables 1-60 to 1-64, p. 1.129 - 1.131
Total	t CH4 / PJ	4.1	
Natural gas			
USA and Canada			
Production	t CH4 / PJ	72	Table 1-60, p. 1.129
Processing, transport and distribution	t CH4 / PJ	88	Table 1-60, p. 1.129
Total	t CH4 / PJ	160	
Eastern Europe and former USSR			
Production	t CH4 / PJ	393	Table 1-61, p. 1.129
Processing, transport and distribution	t CH4 / PJ	528	Table 1-61, p. 1.129
Total	t CH4 / PJ	921	
Western Europe			
Production	t CH4 / PJ	21	Table 1-62, p. 1.130
Processing, transport and distribution	t CH4 / PJ	85	Table 1-62, p. 1.130
Total	t CH4 / PJ	105	
Other oil exporting countries / Rest of world			
Production	t CH4 / PJ	68	Table 1-63 and 1-64, p. 1.130 and 1.131
Processing, transport and distribution	t CH4 / PJ	228	Table 1-63 and 1-64, p. 1.130 and 1.131
Total	t CH4 / PJ	296	

Note: The emission factors in this table have been derived from IPCC default Tier 1 emission factors provided in Volume 3 of the 1996 Revised IPCC Guidelines, by calculating the average of the provided default emission factor range.

CO_2 emissions from LNG

Where applicable, CO_2 emissions from fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($LE_{LNG,CO2,y}$) should be estimated by multiplying the quantity of natural gas combusted in the project with an appropriate emission factor, as follows:

$$LE_{LNG,CO2,y} = FC_y \cdot NCVy.EF_{CO2,upstream,LNG}$$

Where:

$LE_{LNG,CO2,y}$:	=	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 during the year *y* in t CO_2e
FC_y:	=	Quantity of natural gas combusted in the project plant during the year *y* in m^3
$EF_{CO2,upstream,LNG}$:	=	Emission factor for upstream CO_2 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

Where reliable and accurate data on upstream CO_2 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 is available, project participants should use this data to determine an average emission factor. Where such data is not available, project participants may assume a default value of 6 t CO_2/TJ as a rough approximation.[51]

Currently no LNG facility operates in Iran (Source: Confirmation of National Iran Gas Company (NIGC) and therefore, the leakage from LNG is considered to be zero. However, in case LNG becomes available, the calculation would be done according to the explanations above.

Where total net leakage effects are negative ($LE_y < 0$), project participants should assume $LE_y = 0$.

Emission reductions

To calculate the emission reductions the project participant shall apply the following equations:

The emission reductions (ER_y) can be expressed as follows:

$$ER_y = BE_y - PE_y - LE_y \qquad \textbf{(7)}$$

Where:

ER_y	=	Emissions reductions in year *y* (tCO_2)
BE_y	=	Baseline emissions in year *y* (tCO_2)
PE_y	=	Project emissions in year *y* (tCO_2)
LE_y	=	Leakage emissions in year *y* (tCO_2)

B.6.2. Data and parameters fixed ex ante

(Copy this table for each piece of data and parameter.)

Data / Parameter	COEFBL
Unit	tCO2/GJ
Description	The fuel emission coefficient (tCO2e/GJ), based on national average fuel data
Source of data	National average fuel data
Value(s) applied	0.061258

[51] This value has been derived on data published for North American LNG systems. "Barclay, M. and N. Denton, 2005. Selecting offshore LNG process. <http://www.fwc.com/publications/tech_papers/files/LNJ091105p34-36.pdf> (10th April 2006)".

Choice of data or Measurement methods and procedures	Value extracted from official documentation from the Ministry of Energy and from Tavanir. This is in line with methodology requirements.
Purpose of data	Calculation of baseline emissions
Additional comment	The value may be rounded off. For correct decimal points refer ER sheet

Data / Parameter	ηBL
Unit	-
Description	The energy efficiency of the technology of the most likely baseline scenario.
Source of data	Genaveh Energy Conversion Agreement (Heat Rate 11,045 KJ/kWh)
Value(s) applied	32.59%
Choice of data or Measurement methods and procedures	Manufacturer's specifications of baseline gas turbines
Purpose of data	Calculation of baseline emissions
Additional comment	

Data / Parameter	CMy
Unit	tCO2/MWh
Description	The Combined Margin Emission Factor, calculated based on the "Tool to calculate the emission factor for an electricity system" v.4.0
Source of data	Calculated, based on publications by Tavanir.
Value(s) applied	0.72832
Choice of data or Measurement methods and procedures	Official documentation used for the calculation of the Combined Margin in line with the requirements of the "Tool to calculate the emission factor for an electricity system" v.4.0
Purpose of data	Calculation of baseline emissions
Additional comment	

Data / Parameter	BMy
Unit	tCO2/MWh
Description	The Build Margin Emission Factor, calculated based on the "Tool to calculate the emission factor for an electricity system" v.4.0
Source of data	Calculated, based on publications by Tavanir.
Value(s) applied	0.7424
Choice of data or Measurement methods and procedures	Official documentation used for the calculation of the Combined Margin in line with the requirements of the "Tool to calculate the emission factor for an electricity system" v.4.0
Purpose of data	Calculation of baseline emissions
Additional comment	

Data / Parameter	EFNG,upstream,CH4
Unit	tCH4/GJ
Description	Emission factor for upstream fugitive methane emissions of natural gas from production, transportation and distribution
Source of data	IPCC default values
Value(s) applied	0.000296
Choice of data or Measurement methods and procedures	No reliable and accurate national data on fugitive CH4 emissions associated with the production, transportation and distribution of natural gas available
Purpose of data	Calculation of baseline emissions
Additional comment	

Data / Parameter	EFDiesel,upstream,CH4
Unit	tCH4/GJ
Description	Emission factor for upstream fugitive methane emissions of diesel from production, transportation and distribution
Source of data	IPCC default values
Value(s) applied	0.0000041
Choice of data or Measurement methods and procedures	No reliable and accurate national data on fugitive CH4 emissions associated with the production, transportation and distribution of natural gas available
Purpose of data	Calculation of baseline emissions
Additional comment	

Data / Parameter	GWPCH4
Unit	tCO2e/tCH4
Description	Global Warming Potential of Methane valid for relevant commitment period
Source of data	IPCC default value
Value(s) applied	25
Choice of data or Measurement methods and procedures	-
Purpose of data	Calculation of baseline emissions
Additional comment	

Data / Parameter	EFLNG,upstream,CH4
Unit	tCO2/GJ
Description	Emission factor for upstream CO2 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
Source of data	IPCC default values

Value(s) applied	0.006
Choice of data or Measurement methods and procedures	No reliable and accurate national data on fugitive CH4 emissions associated with the production, transportation and distribution of natural gas available
Purpose of data	Calculation of baseline emissions
Additional comment	

B.6.3. Ex ante calculation of emission reductions

Ex-ante calculations of baseline emissions

To calculate baseline emissions, the lowest emission factor among Option 1, Option 2 and Option 3 is calculated:

Option 1: The build margin, calculated according to "Tool to calculate emission factor for an electricity system"

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

Where $\sum_m EG_{m,y} \times EF_{EL,m,y}$ = 32,583,305tCO2e

$\sum_m EG_{m,y}$ = 43,888,156MWh

$EF_{grid,BM,y}$ = 0.7424 tCO2e/MWh (it is rounded off. For actual values refer ER sheets)

Option 2: The combined margin, calculated according to "Tool to calculate emission factor for an electricity system", using a 50/50 OM/BM weight

$$EF_{grid,OMsimple,y} = \frac{\sum_i \left(FC_{i,y} \times NCV_{i,y} \times EF_{CO2,i,y}\right)}{EG_y}$$

$EF_{grid,OM-simple,2009}$ [ton CO_2/MWh]	$EF_{grid,OM-simple,2010}$ [ton CO_2/MWh]	$EF_{grid,OM-simple,2011}$ [ton CO_2/MWh]	Total $EG_{m,2009}$ (excluding low-cost must run) [MWh]	Weight 2009	Total $EG_{m,2010}$ (excluding low-cost must run) [MWh]	Weight 2010	Total $EG_{m,2011}$ (excluding low-cost must run) [MWh]	Weight 2011	Total $EG_{m2009-2011}$ (excluding low-cost must run) [MWh]	$EF_{grid,OM-simple,\ 2009-2011}$ 3 year generation weighted average [ton CO_2/MWh]
A	B	C	D	E=D/J	F	G=F/J	H	I=H//J	J=D+F+H	K=A*E+B*G+C*I
0.71469	0.70120	0.72658	207,543,000	0.3200	218,268,000	0.3366	222,718,000	0.3434	648,529,000	**0.7142**

The combined margin is then calculated as the following:

According to the formula (14) of "Tool to calculate the emission factor for an electricity system" Version 4.0:

$$EF_{grid,CM,y} = EF_{grid,OM,y} \times w_{OM} + EF_{grid,BM,y} \times w_{BM}$$

The project represent no wind and solar project therefore the following default values for other projects will be used for w_{OM} and w_{BM}.

$w_{OM} = 0.5$

$w_{BM} = 0.5$

Hence, the combined margin emission factor would be:

$EF_{grid,CM,y} = 0.7142 \times 0.5 + 0.5 \times 0.7424 = 0.72832$

Option 3: The emission factor of the technology (and fuel) identified as the most likely baseline scenario under "Identification of the baseline scenario" above. Since both diesel and natural gas are used in the most likely baseline scenario, the emission factor of natural gas (which is lower) is used in line with the requirements of AM0029 Version 3. The emission factor is calculated as follows:

$$EF_{BL,CO2}(tco2/Mwh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6GJ/MWh = \frac{0.061258}{32.59\%} * 3.6 = 0.676596$$

The minimum of the emission factors of the three options is used:

$$EF_{BL,CO2,y} = MIN(EF_{BL,CO2,Option1}, EF_{BL,CO2,Option2}, EF_{BL,CO2,Option3}) =$$
$$MIN(0.7424;0.72832;0.676596) = 0.676596$$

Therefore Option 3 is used as the baseline emission factor.

EG_{PJ} is expected to be 3,419,874 MWh/year

Therefore, ex-ante baseline emissions are equal to:

$$BE_y = EG_{PJ,y} * EF_{BL,CO2,y} = 3,419874x0.676596 = 2,313,874 \text{ tCO2e/year}$$

Ex-ante calculations of project emissions (PEy)

Coefficient factor for natural gas:

$COEF_{NG,y} = NCV_{NG,y} * EF_{CO2,NG,y} * OXID_{NG}$ = 0.03657 * 0.061258* 1

$COEF_{diesel,y} = NCV_{NG,y} * EF_{CO2,NG,y} * OXID_{NG}$ = 0.03598 * 0.0741* 1

$FC_{f,y}$ =719,139,936 NM3/year for natural gas including LNG and in HRSG unit

$FC_{f,y}$ =0 litre/year for diésel

Project emissions are based on the projected natural gas used in the power plant in the future.

$$PE_y = \sum_f FC_{f,y} * COEF_{f,y} = 1,611,025 \text{ tCO2e /year}$$

Ex-ante calculations of leakage (LEy)

Fugitive methane emissions:

$$LE_{CH4,y} = \left[FC_y \cdot NCV_y \cdot EF_{NG,upstream,CH4} - EG_{PJ,y} \cdot EF_{BL,upstream,CH4}\right] \cdot GWP_{CH4} =$$

$$[719,139,936 * 0.03657 * 0.000296 - 3,419,874 * 0.00326932] * 25 = -84904 tCO2e$$

CO2 emissions from LNG:

$LE_{LNG,CO2,y} = FC_y \cdot NCVy.EF_{CO2,upstream,LNG}$ =0

<u>Overall leakage emissions:</u>

$LE_y = LE_{CH4,y} + LE_{LNG,CO2,y}$ =--84904 tCO2e/year

Since overall leakage emissions are negative, we conservatively use $LE_y = 0$

Overall, this leads to the following emission reduction calculations:

Year	ERy	BEy	PEy	LEy
1	702,849	2,313,874	1,611,025	0
2	702,849	2,313,874	1,611,025	0
3	702,849	2,313,874	1,611,025	0
4	702,849	2,313,874	1,611,025	0
5	702,849	2,313,874	1,611,025	0
6	702,849	2,313,874	1,611,025	0
7	702,849	2,313,874	1,611,025	0
8	702,849	2,313,874	1,611,025	0
9	702,849	2,313,874	1,611,025	0
10	702,849	2,313,874	1,611,025	0

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

Year	Baseline emissions (t CO_2e)	Project emissions (t CO_2e)	Leakage (t CO_2e)	Emission reductions (t CO_2e)
Year 1	2,313,874	1,611,025	0	702,849
Year 2	2,313,874	1,611,025	0	702,849
Year 3	2,313,874	1,611,025	0	702,849
Year 4	2,313,874	1,611,025	0	702,849
Year 5	2,313,874	1,611,025	0	702,849
Year 6	2,313,874	1,611,025	0	702,849
Year 7	2,313,874	1,611,025	0	702,849
Year 8	2,313,874	1,611,025	0	702,849
Year 9	2,313,874	1,611,025	0	702,849
Year 10	2,313,874	1,611,025	0	702,849
Total	**23,138,740**	**16,110,250**	**0**	**7,028,490**
Total number of crediting years	10			
Annual average over the crediting period	2,313,874	1,611,025	0	702,849

B.7. Monitoring plan

B.7.1. Data and parameters to be monitored

(Copy this table for each piece of data and parameter.)

Data / Parameter	$EG_{PJ,y}$
Unit	MWh
Description	Net quantity of electricity generated by the project power plant in year *y*
Source of data	Measurements by the project participant
Value(s) applied	3,419,874
Measurement methods and procedures	The total amount electricity delivered to the grid is calculated based on the sum of net electricity generated by each of gas units of power plant. Electricity generated by each unit is first delivered into the main transformers to have the voltage conversion from 15.75 kV to 230 kV before connecting to the main grid. Right after each transformer, a measurement system exist that measures the amount of electricity delivered to the grid. The accuracy class of each measurement system is 0.5%.
Monitoring frequency	Continuously
QA/QC procedures	For cross checking, the measurement systems installed on the units can be used. These systems show the gross electricity generated of each unit. By taking auxiliary consumption of electricity and also the electricity loss in the transformers into consideration, the net electricity can be calculated. These amounts can be compared with the net electricity ready to deliver to the grid. Figure 1 at the end of this section illustrates this procedure (for primary and cross checking measurements) The accuracy class of these meters will be of 0.5%. Electricity meters will be subject to regular calibration regime defined by Tavanir. These meters are maintenance free based on the manufactures specification. Calibration shall be in line with the manufacturer`s specification, but at least every 5 years
Purpose of data	Calculation of baseline emissions; Calculation of leakage
Additional comment	The data shall be archived for 2 years following the end of the crediting period.

Data / Parameter	$FC_{NG,y}$ (Natural Gas)
Unit	m^3/yr
Description	Quantity of fuel type Natural Gas combusted during the year y
Source of data	Onsite measurements
Value(s) applied	719,139,936
Measurement methods and procedures	Natural gas is entered into the power plant via a 20 inches pipeline and an ultrasonic flow meter is installed on it before gas goes to the units. The accuracy class of the flow meter is 0.5%.
Monitoring frequency	Continuously
QA/QC procedures	Calibration shall be in line with the manufacturer`s specification, but at least every 5 years. For cross checking the flow meters that have been installed over the units can be used. Figure 2 at the end of this section illustrate this procedure (for primary and cross checking measurements)
Purpose of data	Calculation of project emissions Calculation of leakage
Additional comment	The data shall be archived for 2 years following the end of the crediting period.

Data / Parameter	NCV_{NG},y (Natural Gas)
Unit	GJ/m3
Description	Net calorific of fuel type Natural Gas in year y
Source of data	Fuel Supplier, Local Authority, Country specific, IPCC
Value(s) applied	0.03657
Measurement methods and procedures	Values from official publications will be used
Monitoring frequency	Recording frequency should be on fortnight basis.
QA/QC procedures	No additional QA/QC procedures
Purpose of data	Calculation of project emissions Calculation of leakage
Additional comment	The data shall be archived for 2 years following the end of the crediting period.

Data / Parameter	**$EFCO_{2NG,y}$**
Unit	tCO2/GJ
Description	Emission factor of fuel type Natural Gas in year y
Source of data	National default values
Value(s) applied	0.061258
Measurement methods and procedures	Values from official publications is used
Monitoring frequency	Updated yearly
QA/QC procedures	No additional QA/QC procedures
Purpose of data	Calculation of project emissions
Additional comment	The data shall be archived for 2 years following the end of the crediting period.

Data / Parameter	**$OXID_{NG,y}$**
Unit	%
Description	Oxidation factor of natural gas used by the proposed project plant
Source of data	IPCC
Value(s) applied	1
Measurement methods and procedures	Monitored according to the available data in the latest version of IPCC report
Monitoring frequency	Recording frequency should be on yearly basis
QA/QC procedures	No additional QA/QC procedures
Purpose of data	
Additional comment	The data shall be archived for 2 years following the end of the crediting period.

Data / Parameter	$FC_{Diesel,y}$ (Diesel)
Unit	m^3/yr
Description	Quantity of fuel type Diesel combusted during the year y
Source of data	Onsite measurements
Value(s) applied	0
Measurement methods and procedures	Delivered diesel by the fuel provider is unloaded into the temporary storage and then is pumped to the tankers. Fuels then are flowed to the forwarding pump house to get ready to be injected to the pipelines going to the units. On the way to the units, measurement systems are installed on each of the pipelines to measure the amount of fuel flowed towards the units. The accuracy class of the flow meter is 0.5%.
Monitoring frequency	Continuously
QA/QC procedures	Calibration shall be in line with the manufacturer`s specification, but at least every 5 years. The period of calibration is in line with manufacturer's specifications. Calibration shall be in line with the manufacturer`s specification, but at least every 5 years. For cross checking the flow meters that have been installed over the units can be used. Figure 2 at the end of this section illustrate this procedure (for primary and cross checking measurements)
Purpose of data	Calculation of project emissions Calculation of leakage
Additional comment	The data shall be archived for 2 years following the end of the crediting period. Diesel will be only used as an auxiliary start-up fuel, and will amount to less than 1% of total fuel used, on energy basis.

<table>
<tr><td>Data / Parameter</td><td>NCV_{Diesel},y (Diesel)</td></tr>
<tr><td>Unit</td><td>GJ/liter</td></tr>
<tr><td>Description</td><td>Regional or national default values will be used.</td></tr>
<tr><td>Source of data</td><td>The following data sources shall be used if the relevant conditions apply:
<table>
<tr><th>Data source</th><th>Conditions for using the data source</th></tr>
<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>
<tr><td>(c) Regional or national default values</td><td>If (a) is not available

These data should be based on well documented, reliable sources (such as national energy balances).</td></tr>
<tr><td>(d) IPCC default values as provided in Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories.</td><td>If (a) is not available</td></tr>
</table></td></tr>
<tr><td>Value(s) applied</td><td>0.03598</td></tr>
<tr><td>Measurement methods and procedures</td><td>For (a) and (b): measurements should be undertaken in line with national or international fuel standards.
If a and b are not available For (c)- Regional or national default values</td></tr>
<tr><td>Monitoring frequency</td><td>For (a) and (b): 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</td></tr>
<tr><td>QA/QC procedures</td><td>Values will be verified to fall 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 from the testing laboratory shall be collected to justify the outcome or additional measurements shall be conducted. The laboratories shall have ISO17025 accreditation or justify that they can comply with similar quality standards</td></tr>
<tr><td>Purpose of data</td><td>Calculation of project emissions</td></tr>
<tr><td>Additional comment</td><td>The data shall be archived electronically for 2 years following the end of the crediting period.
Diesel will be only used as an auxiliary start-up fuel, and will amount to less than 1% of total fuel used, on energy basis.
The value of 0.0.3598 is based on national data.</td></tr>
</table>

<table>
<tr><td>Data / Parameter</td><td>$EFCO_{2Diesel,y}$</td></tr>
<tr><td>Unit</td><td>tCO2/GJ</td></tr>
<tr><td>Description</td><td>Weighted average CO_2 emission factor of fuel type diesel oil in year y</td></tr>
<tr><td>Source of data</td><td>One of the following data sources will be used, depending on their availability:
<table>
<tr><td>Data source</td><td>Conditions for using the data source</td></tr>
<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>
<tr><td>(c) Regional or national default values</td><td>If (a) is not available

These sources will be based on well-documented, reliable sources (such as national energy balances)</td></tr>
<tr><td>(d) IPCC default values as provided in table 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories</td><td>If (a) is not available</td></tr>
</table></td></tr>
<tr><td>Value(s) applied</td><td>0.0741</td></tr>
<tr><td>Measurement methods and procedures</td><td>Measurements will be undertaken in line with national or international fuel standards.</td></tr>
<tr><td>Monitoring frequency</td><td>For a) and b): The CO2 emission factor will be obtained for each fuel delivery, from which weighted average annual values will be calculated
For c), the appropriateness of the values will be reviewed annually
For d): Any future revision of the IPCC Guidelines will be taken into account</td></tr>
<tr><td>QA/QC procedures</td><td>For a): If the fuel supplier does provide the NCV value and the CO2 emission factor on the invoice and these two values are based on measurements for this specific fuel, this CO2 factor should be used. If another source for the CO2 emission factor is used or no CO2 emission factor is provided, Options b), c) or d) should be used.</td></tr>
<tr><td>Purpose of data</td><td>Calculation of project emissions</td></tr>
<tr><td>Additional comment</td><td>The data shall be archived electronically for 2 years following the end of the crediting period.
Diesel will be only used as an auxiliary start-up fuel, and will amount to less than 1% of total fuel used, on energy basis.
The value of 0.0741 is based on data source d- IPCC.</td></tr>
</table>

Data / Parameter	$OXID_{Diesel,y}$
Unit	%
Description	Oxidation factor of natural gas used by the proposed project plant
Source of data	IPCC
Value(s) applied	1
Measurement methods and procedures	Monitored according to the available data in the latest version of IPCC report
Monitoring frequency	Recording frequency should be on yearly basis
QA/QC procedures	No additional QA/QC procedures
Purpose of data	
Additional comment	The data shall be archived for 2 years following the end of the crediting period.

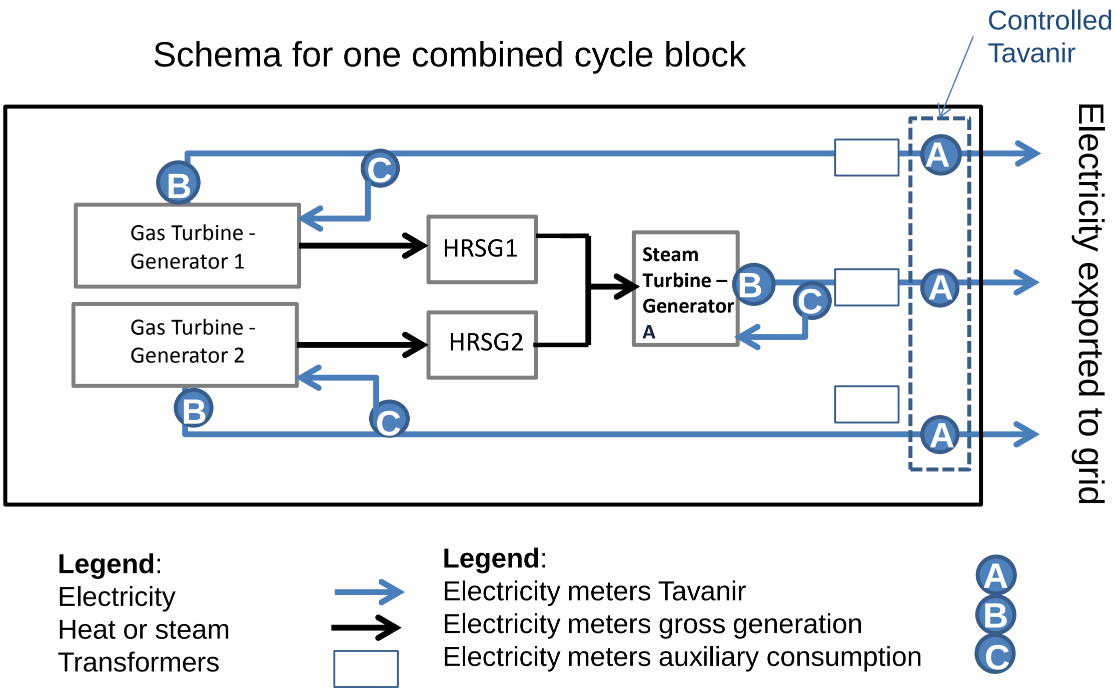
Data / Parameter	GWP_{CH4}
Unit	tCO_2e/tCH_4
Description	Global Warming Potential of Methane valid for relevant commitment period
Source of data	IPCC default value
Value(s) applied	25
Choice of data or Measurement methods and procedures	-
Purpose of data	Calculation of baseline emissions
Additional comment	

If LNG becomes available and is used during monitoring period, the monitoring plan for would be like the following table:

Data / Parameter	$FC_{LNG,y}$
Unit	Nm^3/yr
Description	Quantity of fuel type LNG used by the project power unit(s) in year *y*
Source of data	Onsite measurements
Value(s) applied	0
Measurement methods and procedures	Natural gas is entered into the power plant via a 20 inches pipeline and an ultrasonic flow meter is installed on it before gas goes to the units. The accuracy class of the flow meter is 0.5%.
Monitoring frequency	Continuously
QA/QC procedures	Calibration shall be in line with the manufacturer`s specification, but at least once in five years. For cross checking the flow meters that have been installed over the units can be used.. Figure 2 at the end of this section illustrate this procedure (for primary and cross checking measurements)
Purpose of data	Calculation of project and leakage emissions
Additional comment	The data shall be archived electronically for 2 years following the end of the crediting period.

Data / Parameter	$FC_{HRSG, NG,y}$
Unit	Nm^3/yr
Description	Quantity of fuel type natural gas used in HRSG in year *y*
Source of data	Onsite measurements
Value(s) applied	0
Measurement methods and procedures	Natural gas is entered into the power plant via a 20 inches pipeline and an ultrasonic flow meter is installed on it before gas goes to the HRSG units. The accuracy class of the flow meter is 0.5%.
Monitoring frequency	Continuously
QA/QC procedures	Calibration shall be in line with the manufacturer`s specification , but at least once in five years. For cross checking the flow meters that have been installed over the units can be used.
Purpose of data	Calculation of project and leakage emissions
Additional comment	Only natural gas is proposed to be used in HRSG units. The data shall be archived electronically for 2 years following the end of the crediting period.

The basic schema for combined cycle power plant and the monitoring process is



:

Figure 1 : Monitoring procedure for the amount of electricity generated

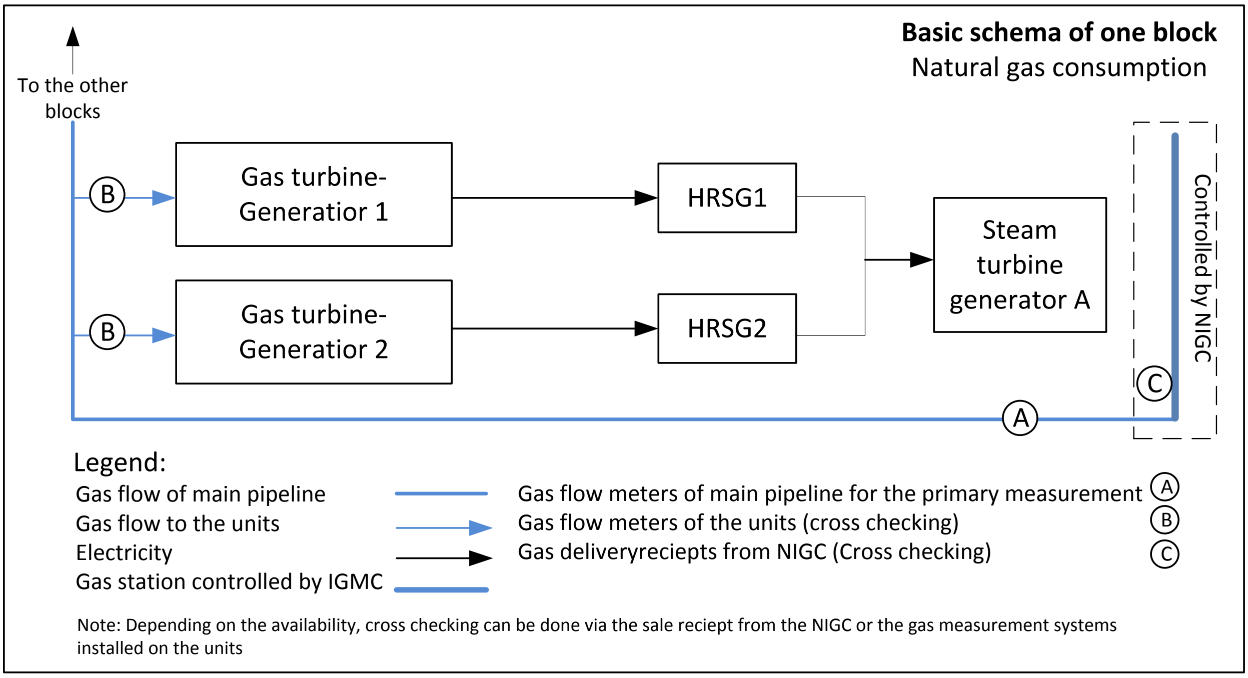


Figure 2: Monitoring procedure for the amount of gas consumed in gas units

B.7.2. Sampling plan

No sampling approach used to determine monitoring data.

B.7.3. Other elements of monitoring plan

Responsibilities for monitoring

At the plant a *CDM Manager* will be trained to supervise the collection, aggregation and storage of the required data from the regular monitoring activities, as well as the calibration and maintenance of the measurement equipments. The *Data Recorders* and *Meter Supervisors* will take charge of the regular monitoring tasks, and will provide the relevant data to the CDM Manager.

All staff involved in any of the procedures related with the CDM project activity will be trained in order to perform the tasks specified in the monitoring plan by the CDM consultant.

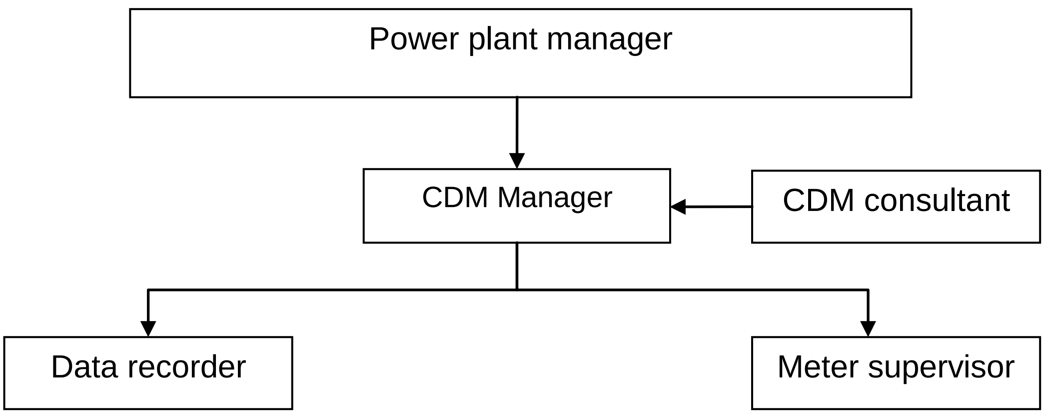
Operational Management

The detailed calibration, testing and maintenance results for the measurement equipments used to monitor data of the project activity shall be prepared by the *CDM Manager* based on the stipulations in the monitoring plan.

The data collected as part of monitoring will be archived electronically and be kept at least for 2 years after the end of the last crediting period. Records used for monitoring which are not available in electronic format will be scanned but also stored physically. The records for calibration, testing and maintenance of meters will be accessible for the DOE during verification

All electronic data, except for the electricity readings by Tavanir which are not under the control of the project participant, will be remotely monitored and recorded from the power plant control centre by the DCS. Transmitters will be calibrated as per manufacturer's specifications. Staff working at the control centre will prepare a report on the operations of the CDM project activity and this report will record data readings and equipment defects, outages, repairs and maintenance activities. All relevant information, notes of meetings, data files, maintenance records, defect reports, hard copy and computerized records of monitoring will be kept at the control centre or other designated location, and arranged in an orderly and transparent manner to facilitate audit as and when required.

Operation and Management structure:



Group members and their responsibilities

Person	Responsibility
Power plant manager	Supervises the implementation of monitoring plan
CDM Manager	Managing the whole CDM data processing for project power plant, guiding and supervising data recorder after training by CDM

	consultant.
CDM consultant	Providing CDM Manager training and technical support about CDM monitoring plan.
Data recorder	Collecting and recording data every month.
Meter supervisor	Checking power meter periodically according to relevant regulation.

Emergency preparedness

To prevent any loss during the uncertainties and emergencies, the metering process is designed in a way that can protect all the recorded data. The energy metering systems installed shall under any circumstance be able to measure the delivered energy and received energy and should make a continuous recording of such delivered and received energy on an appropriate magnetic media or equivalent..

The metering devices of energy metering systems shall consist of two stations namely a main station metering devices and a backup station of metering devices.

The metering devices shall be read by representatives of the company and Tavanir at 00:00 on the first day of each month and a metering device reading protocol shall be immediately issued by the company and Tavanir at the place of such reading stating the delivered energy and received energy for the previous month. If the representative of neither of the company or Tavanir is not present for execution of the protocol on the first day of a month, the protocol shall be issued only by the representative of the party who is present.

The accuracy and calibration of the energy metering systems shall be tested by representative of both parties (Tavanir and the company.

If any fault is detected beyond the acceptable accuracy class for the metering devices, the parties shall utilise the backup metering devices and if any fault is detected also on the backup metering devices, the parties shall utilise the metering devices at Tavanir`s substation where the measurement shall be adjusted for line losses between the power station and Tavanir`s substation.

Should any of the required readings not be available, the project participants will agree on a conservative proxy with the verifying DOE.

Annex 5 contains further background information.

B.7.4. Date of completion of application of methodology and standardized baseline and contact information of responsible persons/ entities

10/09/2013, for contact information please refer Appendix 1 of this PDD for details

SECTION C. Duration and crediting period

C.1. Duration of project activity

C.1.1. Start date of project activity

08/06/2009 – Earliest date of commitment towards project implementation (Effective Date of pre EPC)

C.1.2. Expected operational lifetime of project activity

25 years, 0 months

C.2. Crediting period of project activity

C.2.1. Type of crediting period

Fixed crediting period

C.2.2. Start date of crediting period

20/05/2014 or date of registration, whichever is later

C.2.3. Length of crediting period

10 years, 0 months

SECTION D. Environmental impacts

D.1. Analysis of environmental impacts

An Environmental Impact Assessment for Genaveh Combined Cycle Power Plant is carried out in March 2009. The assessment is approved by the Bushehr Environmental Protection Organization on February 23 2010.

D.2. Environmental impact assessment

Considering the situation of the project, the review of the specifications and the impacts the project can have on the environment, environmental impact assessment has been made which shows that in overall the project has the positive impact of 22. Following table shows the final results of environmental impact assessment:

	Natural environment	Biological environment	Socio-economic environment	Aggregation of the scores
Option 1- Implementation of the project	-217	-18.2	+582	+22
Option 2 – No project in the current site	+19.25	+2	-92.15	-71.9

As can be seen, aggregated amounts for both options (implementation or not implementation) show that option one takes the precedence over option 2. So, the project has positive impact.

SECTION E. Local stakeholder consultation

E.1. Solicitation of comments from local stakeholders

A meeting with the local stakeholders was conducted on Wednesday, July 27, 2011 at Genaveh Power Plant which is located in: 20th Km of Genvah-Borazjan way, Between Poozgah & Chahar Roostaee, Genaveh Combined Cycle Power Plant

The important local stakeholders were identified as the locals residing in the neighbouring villages, local health officer, staff of neighbouring college, officials of state electricity board and pollution control board. Most of these are residents of the neighbouring areas in the project site and are likely to be affected by the project.

All the identified stakeholders were invited 15 days in advance before the meeting.

Public announcement was made in a local newspaper on July 27 2011 in "Iran Zamin Behshahr".

To receive the participant's comments and their evaluation about the meeting, a LSC Meeting Evaluation/Comment Form was prepared for each participant and all the participants were asked to fill out the form. The form was included following sections:

1. Full Name (Optional):
2. What is your impression about the meeting?
3. Please give us your comments briefly with the reasons mentioned in connection with the positive aspects of the project.
4. Please give us your comments briefly with the reasons mentioned in connection with the negative aspects of the project.
5. Any suggestion or criticism related to the project, please describe briefly in this section.

E.2. Summary of comments received

During the discussions, the following points were raised:

1. How emission reduction of combined cycle power plant & other projects will be calculated in CDM? Mr. Ghaliani, a local representative.
   The question was answered by Mr. Mehdizadeh (MD of AJE Co.); he explained via presentation & also he added that there are some methodologies which registered in the UNFCCC for each project & combined cycle Power Plant has a related methodology which Co2 reduction will be calculated via it. The methodologies are available in the http://cdm.unfccc.int/ .
2. When the CDM benefit will be born for the project? Is it possible to receive it before the commissioning? Mr. Gholami from Jihad Agriculture.
   The question was answered by Mr. Mehdizadeh (MD of AJE Co.); as explained in the Presentation the CDM benefit which will be receive as CERs will be born after project commissioning and if no emission reduction accrued, so no CERs will be born accordingly, so the project should be commissioned to receive the CDM benefit.
3. Is there any possibility except the Combined Cycle projects to develop as CDM project? Asked by Mr. Yazdan Shenas, Genaveh Governor.

The question was answered by Mr. Mozafri (MD of MAPNA Genaveh Power Generation Company) & Mr. Mehdizadeh (MD of AJE Co.); each project which can reduce the emission can be a CDM Project, but there are some limitations on project definition. In the Kyoto protocol 6 gases are introduced as green house gases: CO_2, CH_4, N_2O, Hydro fluorocarbons, PFCs & SF_6 which explained in the presentation. Also when a project is feasible without the CDM revenue and can develop without it, so cannot develop as a CDM project. The CDM revenue will help the project owner to develop the projects which reduction the emission & will be feasible with CDM revenue only.

E.3. Report on consideration of comments received

The stakeholders attending the local stakeholder consultation meeting were all very supportive to the proposed project. There were no objections received during the investigation.

Comment	Clarification
What would be the role of Genaveh CC power plant in the grid?	It was clarified that the nature of this project is to increase the amount of available electricity within the grid and also it helps to minimize supply shortages during the peak times.

What are the project goals?	It was explained that this project aims to increase the efficiencies in two ways: One is to bring down the emissions resulted from inefficient open cycle power plant. The other is to increase the efficiency overall. Comparing with the open cycle mode, the combined cycle generates electricity with much higher efficiency. Moreover, this person was directed to the existing methodologies in the UNFCCC platform.
When the benefits of registration under CDM will be given to the project participants?	The benefits including the issuance of CERs will be dedicated to the project upon the verification of the project once the monitoring procedure has been successfully carried out.

SECTION F. Approval and authorization

The letter of approval from the host country (The Islamic Republic of Iran) has been received.

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Appendix 1. Contact information of project participants and responsible persons/ entities

Project participant and/or responsible person/ entity	☒ Project participant ☒ Responsible person/ entity for application of the selected methodology (ies) and, where applicable, the selected standardized baselines to the project activity
Organization name	MAPNA Genaveh Power Generation Co.
Street/P.O. Box	South Naft St. Corner, Mirdamad Ave.
Building	282
City	Tehran
State/Region	Tehran
Postcode	
Country	Iran
Telephone	+98 (21) - 81984258
Fax	
E-mail	
Website	
Contact person	
Title	Managing Director
Salutation	Mr
Last name	Mozafari Goudarzi
Middle name	
First name	Shahpour
Department	
Mobile	
Direct fax	
Direct tel.	+98 (21) - 81984258
Personal e-mail	

Project participant and/or responsible person/ entity	☒ Project participant ☒ Responsible person/ entity for application of the selected methodology (ies) and, where applicable, the selected standardized baselines to the project activity
Organization name	Swiss Carbon Assets Ltd.
Street/P.O. Box	Technoparkstrasse
Building	1
City	Zurich
State/Region	Zurich
Postcode	8005
Country	Switzerland
Telephone	+41 43 501 35 50
Fax	+41 43 501 35 99
E-mail	info@southpolecarbon.com

Website	www.southpolecarbon.com
Contact person	Renat Heuberger
Title	Managing Partner, CEO
Salutation	Mr.
Last name	Heuberger
Middle name	
First name	Renat
Department	
Mobile	
Direct fax	+41 43 501 35 99
Direct tel.	+41 43 501 35 50
Personal e-mail	info@southpolecarbon.com

Appendix 2. Affirmation regarding public funding

There is no public funding for the project activity.

Appendix 3. Applicability of methodology and standardized baseline

As discussed above

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

<u>Key variables for calculating the project emissions:</u>

Variable	Value	Unit	Source
$FC_{NG,y}$:	89000	Nm3/hour	FSR
Avaialbility	92.24%		ECA
$FC_{NG,y}$:	719,139,936	Nm3/year	Average value from FSR
$NCV_{NG,y}$:	0.03657	GJ/Nm3	Calculated, based on sources of Ministry of Energy and Tavanir. See excel CM_2009_2011 "BasisNCVCO2" tab
$EF_{CO2,NG,y}$:	0.061258	tCO2/GJ	Calculated, based on sources of Ministry of Energy and Tavanir. See excel CM_2009_2011 "BasisDataCO2" tab
$OXID_{NG}$:	1	-	IPCC default value

Variable	Value	Unit	Source
$FCDiesel_{,y}$:	0	Litre/year	FSR
$NCVDiesel_{,y}$:	0.03598	GJ/litre	Calculated, based on sources of Ministry of Energy and Tavanir. See excel CM_2009_2011 "BasisNCVCO2" tab
$EF_{CO2,Diesel,y}$:	0.0741	tCO2/GJ	IPCC default value
OXIDDiesel :	1	-	IPCC default value

Project emissions calculation:

Year	*PEy*
1	1,611,025
2	1,611,025
3	1,611,025
4	1,611,025
5	1,611,025
6	1,611,025
7	1,611,025
8	1,611,025
9	1,611,025
10	1,611,025

<u>Key variables for calculating the baseline emissions:</u>

1. Option 1: Build Margin 0.7424 tCO2e/MWh
2. Option 2: Combined Margin = 0.72832 tCO2e/MWh
3. Option 3: Emission factor of the baseline technology = 0.676596 tCO2e/MWh

Variable	Value	Unit	Source
$COEF_{BL}$:	0.061258	tCO2/GJ	Calculated, based on sources of Ministry of Energy and Tavanir. See excel CM_2009_2011 "BasisDataCO2" tab
h_{BL} :	32.59%		Genaveh Energy Conversion Agreement for gas units (Heat Rate 11,045 KJ/kWh)
$EF_{BL,CO2}$:	0.676596	tCO2e/MWh	calculation

=> Option 3 has the lowest emission factor.

Therefore, baseline emissions are as follows:

Variable	Value	Unit	Source
Gross capacity CC power plant	484	MW	EPC
Net capacity CC power plant	423.24	MW	ECA
Average availability of CC power plant	92.24%		ECA

Baseline emissions calculation:

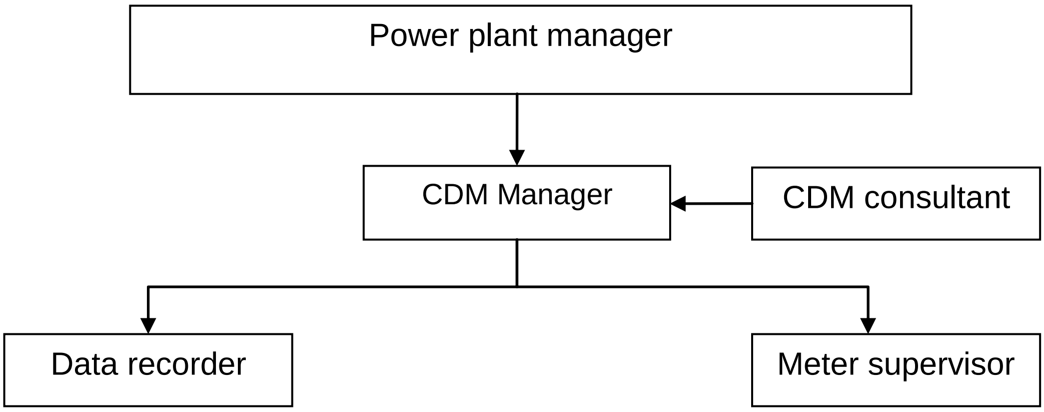
Year	*Net EG $_{PJ,y}$*	*BEy*
1	3,419,874	2,313,874
2	3,419,874	2,313,874
3	3,419,874	2,313,874
4	3,419,874	2,313,874
5	3,419,874	2,313,874
6	3,419,874	2,313,874
7	3,419,874	2,313,874
8	3,419,874	2,313,874
9	3,419,874	2,313,874
10	3,419,874	2,313,874

Emission reduction calculation:

Year	*ERy*	*BEy*	*PEy*	*LEy*
1	702,849	2,313,874	1,611,025	0
2	702,849	2,313,874	1,611,025	0
3	702,849	2,313,874	1,611,025	0
4	702,849	2,313,874	1,611,025	0
5	702,849	2,313,874	1,611,025	0
6	702,849	2,313,874	1,611,025	0
7	702,849	2,313,874	1,611,025	0
8	702,849	2,313,874	1,611,025	0
9	702,849	2,313,874	1,611,025	0
10	702,849	2,313,874	1,611,025	0

Appendix 5. Further background information on monitoring plan

A. Operation and Management structure:



Group members and their responsibilities

Person	Responsibility
Power plant manager	Supervises the implementation of monitoring plan
CDM Manager	Managing the whole CDM data processing for project power plant, guiding and supervising data recorder after training by CDM consultant.
CDM consultant	Providing CDM Manager training and technical support about CDM monitoring plan.
Data recorder	Collecting and recording data every month.
Meter supervisor	Checking power meter periodically according to relevant regulation.

B. Monitoring procedure

The steps of monitoring the electricity supplied to the grid and the fuel supplied to the power plant are as follows:

(1) The electricity supplied by the project to the grid will be automatically monitored. The data is measured continuously.

(2) Persons in charge of data record and meter supervisor from power plants shall read and collect data from power and fuel meters at the end of every month.

(3) Copies of invoices for electricity and fuel (diesel and natural gas) supplies are stored by CDM Manager for double checking.

C. Data recording and archiving procedures

- The CDM Manager shall keep monitored data in electronic archives at the end of every month. Paper documents should also be compiled and saved monthly.
- Power plant shall keep copies of electricity sales and fuel purchase invoices
- In order to help verifiers obtain documents and information related to the emission reduction of the proposed project, CDM Manager shall prepare an index of the data documents compiled
- All the data shall be kept for 2 years after the crediting period.

D. Training

The CDM consultant will in close collaboration with the power plant manager train the CDM Manager to ensure effective monitoring of all parameters in line with the monitoring plan.

Appendix 6. Summary of post registration changes

Nil

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Document information

Version	Date	Description
05.0	25 June 2014	Revisions to: • 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;* • 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).
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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