Response Matrix for CTF Program Approval Request Update II			
1. Country/Region	Turkey	**2. Date**	05-11-2014
3. Project/Program Title	Turkey Geothermal Development Facility (GEODELF)		
Questions from Germany			
How long will the Tenor of the Senior Loans be (should be in Table 2 on p. 6 but is not readable)?	Up to 10 years, to account for the possibility of failure, and then allowing the sponsor more time to repay. In the case of conversion to EBRD loan conditions in Phase II, the EBRD conditions would apply, which could increase the tenor (but not beyond 20 years).		
How high will the Interest rate of the Senior Loans be (should be in Table 2 on p. 7 but is not readable)? The Interest rate should reflect the "high risk of the investment" (p. 4), given that in case of drilling failure the SPVs might not be able to repay the loans. Also an adjustment of the minimum level for the corporate guarantees for the SPVs should be reflected, which is so far intended to "covering at least 50% of the CTF Loan".	75 bps/yr with a commitment fee of no less than 50 bps, negotiated on a project by project basis. The high level of concessionality during the drilling period is chosen to encourage drilling projects to go forward by providing low-cost capital. The risk/reward ratio in turn is being addressed by either: i) Providing upside to the CTF in the form of participation on EBRD terms in Phase II, where a typical loan at present market rates could expect to receive around 400-450 bps + LIBOR per year; or ii) The special dividend of no less than 350 bps which will be charged at the repayment of the principal in case CTF does not participate in Phase II. On a typical three-year loan, the average CTF income will therefore be no less than 200 bps if there is no CTF participation after Phase I. This would increase to about 370 bps on average for a 13 year participation (3 years drilling followed by 10 years senior loan). It should be noted that all these figures are indicative.		
Follow-up questions			
We would like you to expand on your answer to the second market transformation potential question as this is rather short, specifically discussing how drilling risk will be addressed in the future. It is not clear currently whether your comments only relate to financing for power plant development.	The comments relate to drilling risk and the ability to raise money for it. Having operating assets that generate cash will enable the new operators to take on exploration risk for future GPPs on their own balance sheet, and to raise lines of credit with commercial banks that can finance this expansion.		
If you expect a continuing role for public finance to address the high risks associated with drilling, then please be clear about this as this.	The operation has to be seen in the context of the overall DPSP programme, where substantially larger funds will be made available by IBRD in a separate transaction. We would however hope that the demonstration of the potential of the market and the area provided by these operations will ultimately lead to the development of private sector solutions in which high-risk capital can be made available for similar financial structures.		
On the first results framework question, please	The cost for Dual Flash GPP is given on average about		

can you be more transparent about your assumptions driving the high cost per MW installed. Our economist has noted that this is significantly higher than in other DPSP proposals we have seen so we want to be very clear about why this is higher.	USD5 million per MW, but can vary between USD 3.5-6.2 m/MW, depending on a variety of factors. Binary GPP is a bit cheaper at around USD4.8m/MW, but not much. It can also vary in the same range, based on our database from USD 3.6-6.1 m/MW. So we think it is safe to assume about USD5 m/MW as average cost with an extra 20% tolerance for unforeseen (depending on terrain, size of project, amount of piping to be laid out etc). Furthermore, the RMF notes that the capacity target is "at least" 50MW, so if the cost ends up cheaper, we would expect it to be exceeded by simply putting more MW in the ground.
Terms of CTF funds:	
Could EBRD clarify how they would expect to support up to 9 projects by recycling CTF resources from an initial round of investments?	We expect to do a maximum of USD7.5m per project for a duration of three years, which gives us at least three projects in round 1. Presuming it is all repaid, we could then use this up to two more times (3 years each), so we could do up to three rounds with at least three projects.
We are concerned that the special dividend proposed on the CTF loan could act as a disincentive on project developers to seek out commercial loan resources from other lenders. Could EBRD explain the rationale behind the special dividend charged to project developers not seeking phase II finance from EBRD?	The special dividend will be charged in order to reimburse CTF for the risk taken if CTF does not participate further. There are only two ways to provide upside to the CTF: i) the special dividend on exit at the end of Phase I; and ii) continued participation on EBRD terms in Phase II. The point of the special dividend is also to ensure that for the projects with initial CTF participation in the drilling stage, the developer has an incentive to deal with EBRD for the construction phase, in order to ensure that appropriate standards are being followed, e.g. environmental H&S, safety.
Market transformation potential	
We understand that the Turkish geothermal market is dynamic but has a high market concentration. Will this programme work with new market entrants exclusively, and if not, why not?	The product is aimed at primarily at new entrants. We do not think that existing larger operators would require this kind of support. We would however like to keep the flexibility to also work with some existing operators, especially smaller ones, who could also benefit from this. But we would not expect large conglomerates to benefit from this product.
What is the theory of change behind the private sector being able to take over the development of the geothermal sector in the country after the completion of this programme?	We would expect to have more operators with existing assets generating cash and providing security based on which they will find it easier to access commercial finance. It is a similar theory to that applied in the Ukraine Sustainable Energy Lending Facility for renewables.
Results framework	

Could EBRD elaborate on the assumptions that underlie the current expectation of at least 50MW of power capacity supported and $300m co-finance leveraged – including assumptions on drilling risk and investment costs? Please show how these results expectations would change if the TFC approves the recycling the CTF investment component?	The assumptions are based on the cost per MW installed, and specific drilling cost. In the best case, the results would scale up. We conservatively estimate cost per MW installed at USD6,000/MW. While the example given on p.7 of the application is for a project where the drilling cost is exactly USD 7.5 million, for any project with higher drilling cost the sponsor would provide 100% of the cost exceeding USD 15 million. We expect the average share of drilling cost in Turkey to be about 20-30% of the total project value.
We were surprised to see that carrying out CTF-specific reporting requirements is financed from a separate Evaluation and Knowledge Management budget and not from MIPS. What is the rationale for this?	We have done this in a number of projects now. The MIPS covers EBRD's normal cost in administering the project. Where CTF specific project level reporting and evaluation goes beyond the normal EBRD approach, we cover it from the separate budget, since it is carried out by the same people internally who work on the KM aspects.