ECONOMIC ANALYSIS

A. Background

1. Under India's tenth and eleventh five-year plans (FY2003–FY2012), the Power Grid Corporation of India (POWERGRID) has focused on the creation of a national electricity grid. POWERGRID has been expanding its transmission network in a phased manner to further integrate this national grid, evacuate expanding power supplies, and increase the transfer of power between the country's five regional power grids. By the end of the twelfth five-year plan (FY2013–FY2017), POWERGRID plans to invest about $22 billion to more than double the size of its network. This is crucial to delivering new power supplies from new generation plants being developed by public and private utilities.

2. Despite its relatively strong financial capacity, POWERGRID faces a challenge in raising all necessary funds in the domestic debt and equity markets to complete this expansion. A significant part of funding has come from foreign sources including the Asian Development Bank (ADB) and the World Bank. However, to support the future larger investment plan, POWERGRID will need to expand and diversify its sources of debt capital by tapping the commercial lending market and beginning to reduce its current reliance on only two sources of debt: domestic bond issues (67% of total debt outstanding) and sovereign guaranteed loans of multilateral banks (27%).

3. Pursuant to the requirements of a long-term open access program in the interstate transmission system under regulations of the Central Electricity Regulatory Commission (CERC) in 2004, POWERGRID was requested to construct high voltage direct current (HVDC) transmission lines by 55 independent power producer (IPP) generation developers seeking long-term open access for new generation projects proposed under the delicensed regime. To meet the additional bulk power transfer needs of these IPP plants, nine high capacity transmission corridors will be needed. The project proposed for ADB finance is the biggest of these transmission schemes and associated with 14 IPPs and a public power trading company in the state of Chhattisgarh in the western power region. It will supply power to the northern region of India. India's open access power transmission network and the associated bilateral contracts market are still in infancy. The private sector is understandably cautious about committing capital to an unproven market. This puts the onus on the public sector to demonstrate the market's viability, which in turn requires and justifies public sector intervention.

B. Approach

4. In accordance with ADB's *Guidelines for Economic Analysis of Projects*,[1] the economic analysis has treated the two components of the proposed investment as integrated facilities. Component 1 is the 800 kV HVDC interregional transmission system. Component 2 is an associated 400 kV transmission system strengthening in the northern region. The analysis used the 11th National Electricity Plan (Transmission) of the Central Electricity Authority (CEA) and the POWERGRID's investment plan to verify

- (i) electricity demand and supply projections for the northern region;
- (ii) the presence of the project on the regional and national least-cost system expansion paths;
- (iii) economic cost–benefit analysis of the project, including sensitivities to key variables; and
- (iv) distribution of costs and benefits among stakeholders.

[1] ADB. 1997. *Guidelines for the Economic Analysis of Projects.* Manila.

5. **Demand forecast**. The CEA prepares national electricity demand forecasts using the electric power survey (EPS).[2] The latest EPS was published in 2007. The EPS employs both top-down and bottom-up forecasting techniques. It assumed that electricity generated by the IPPs in Chhattisgarh would be consumed within the northern region, including the states of Punjab, Haryana, Delhi, Uttar Pradesh, and Rajasthan. Table 1 shows the forecast of aggregate peak demand and supply in these five states.

Table 1: Northern Region Peak Power Demand and Supply Forecast[a]
(megawatt)

		2008	**2010**	**2012**	**2014**	**2016**	**2018**
Demand	Winter	29,373	29,709	34,034	38,651	44,415	50,185
	Monsoon	33,993	34,568	39,537	44,809	51,273	57,854
	Summer	32,836	33,621	38,399	43,490	49,716	56,083
Supply	Winter	26,499	29,495	36,862	41,252	44,501	45,834
	Monsoon	29,852	31,975	41,272	46,363	49,878	51,592
	Summer	28,283	30,354	39,119	44,132	47,430	49,069
Regional Surplus/Deficit	Winter	(2,874)	(1,214)	2,828	2,601	86	(4,351)
	Summer	(4,141)	(2,593)	1,735	1,554	(1,396)	(6,262)
	Monsoon	(4,553)	(3,267)	720	642	(2,286)	(7,014)

[a] The states of Himanchal, Uttarakhand, and Jammu and Kashmir are not included.
Source: Central Electricity Authority.

6. **Least-cost planning.** The planning approach adopted by POWERGRID derives an integrated transmission plan using both top-down and bottom-up inputs. Development of the transmission plan is iterative. Various input (power station) scenarios and offtake (grid substation) scenarios, with- and without-project, are modeled and analyzed to identify the least-cost means of developing the transmission network under a reasonable range of scenarios. In this sense, the transmission network development plan encapsulated in the proposed investment project is the least-cost means of achieving a desired set of electricity transmission outcomes.

7. **Project costs.** All costs have been expressed at constant mid-2011 prices. The domestic price numeraire was used; tradable inputs were valued at their border price equivalent value (BPEV) and were converted to domestic equivalents using an estimated standard exchange rate factor of 1.05. Capital costs for the project were taken from POWERGRID's detailed project report, with appropriate adjustments to remove taxes, financing costs, and price contingencies. An operation and maintenance (O&M) cost allowance of 1.5% of capital costs was assumed, as per the CEA estimates for new transmission lines.

8. Specific capital costs for coal-fired generation plants were assumed equivalent to the all-India planning parameters of Rs45,000 per kilowatt (kW), or approximately $1,000 per kW. Coal fuel for thermal power plants was initially valued at its BPEV. Typical loading and transport costs, excluding taxes, were added to base fuel prices to derive BPEV of Rs1,815 per ton, or about $40 per ton at mid-2011 prices. Total variable costs for electricity delivered at the power station gate were calculated to be Rs1.51 per kilowatt-hour (kWh), with an overall average cost of Rs2.49 per kWh.

9. It is generally acknowledged that significant investment is required in downstream distribution systems to improve supply quality and reliability and to reduce losses. Investments in supply reliability tend to be localized and do not typically become the part of

[2] Central Electricity Authority, Government of India. 2007. *17th Electric Power Survey of India*. New Delhi.

the national electricity plan. Therefore, no provision has been made for capital and operating costs associated with relieving downstream capacity constraints, as the benefits of system reliability improvements, automation, and non-technical loss reduction were not included in the analysis and related capital and operating costs were consequently excluded.

10. **Project benefits.** All benefits have also been expressed at constant mid-2011 prices. The main economic benefits of the proposed investments are incremental consumption through the meeting of the demand not now being met in the northern region and the displacement of generation from captive diesel plants that compensate for the present power deficit.

11. Based on forecasts for seasonal and peak and off-peak demand and supply of electricity in the five states in the northern region and the IPPs' generation availability from the project, the analysis calculated seasonal and time-of-day and the annual estimates of the amount of incremental and non-incremental consumption of electricity that the project would enable in the northern region during the planning horizon.[3]

12. Electricity supplied from the project will be used to meet any unserved demand for electricity in the northern region. When there is no unserved demand in the Northern region, electricity supplied from the project will be used to displace more expensive sources of generation, primarily diesel captive plants.

13. Nonincremental outputs were valued at the resource cost savings that would accrue if the investment project was to proceed. Resource cost saving was assumed to occur when

(i) captive generation that would have been required to meet demand in the without-project scenario is replaced with IPP generation from the Chhattisgarh region in the with-project scenario,[4] and
(ii) it was assumed that most captive generation will be displaced before any expensive coal-fired generation in the northern region is displaced.

14. Incremental outputs were valued using consumers' estimated willingness to pay for incremental consumption. The methodology outlined in ADB's Economic and Research Department technical note no. 3 *Measuring Willingness to Pay for Electricity* was followed.[5] For selected consumer categories, demand functions relating energy price to energy demand were estimated using regression analysis. The demand function and the incremental consumption were used to determine willingness to pay. The weighted average for willingness to pay (WTP) for additional units of consumption was estimated as Rs3.81 per kWh in the northern region.[6]

15. **Estimation of economic internal rate of return.** A period of 20 years for the project's economic life was used for economic evaluation. Capital investment is assumed to take place in the period 2012–2016 and benefits are assumed to be realized from 2017. Residual values are estimated for equipment based on a 50-year economic life for transmission assets. The capital costs are determined as explained above, by subtracting

[3] The peak periods last 4 hours per day and each season (winter, monsoon, and summer) lasts 4 months.
[4] The CEA's 17th EPS estimates a total of 24,018 million units (MU) of installed generation of captive plant in the northern region by FY2012, with 16,572 MU of that coming from steel-based generation. Diesel-based (2,882 MU) and gas-based (4,563 MU) make up the balance. Of 24,018 MU, 22,843 MU pertains to the five states under consideration. The CEA does not include diesel plants smaller than 1 MW in its review but has verbally indicated it estimates an installed capacity of sub-1 MW diesel sets equivalent to that of greater than 1 MW diesel sets on a conservative basis. BPEV of diesel (Rs33.65/liter), specific consumption of 0.3 liters/kWh, and non-fuel O&M of Rs0.2/kWh to give total variable cost of Rs. 10.29/kWh.
[5] ADB. 2002. *ERD Technical Note No. 3 Measuring Willingness to Pay for Electricity.* Manila.
[6] Willingness-to-pay estimates were Rs3.69/kWh for domestic consumers, Rs4.71/kWh for industrial consumers, Rs6.00/kWh for commercial consumers, Rs2.03/kWh for agricultural consumers, and Rs2.49/kWh for others.

the taxes and adding the physical contingencies to the total base cost. The combined estimated economic internal rate of return (EIRR) is 22.1%. EIRR is shown in Table 2.

Table 2: Economic Internal Rate of Return Calculation
(Rs million)

Year	Benefits (Rs million)			Costs (Rs million)				Net benefits
	Incremental	Nonincremental	Total benefits	Capital	O&M	IPP	Total costs	
2013	-	-	-	9,487	-	-	9,487	(9,487)
2014	-	-	-	12,523	-	-	12,523	(12,523)
2015	-	-	-	31,761	-	-	31,761	(31,761)
2016	-	-	-	14,509	-	-	14,509	(14,509)
2017	10,276	1,327	11,603	8,001	286	10,085	18,373	(6,770)
2018	57,052	6,537	63,589	-	1,144	46,019	47,164	16,426
2019	68,531	4,903	73,434	-	1,144	49,700	50,844	22,590
2020	68,531	6,537	75,068	-	1,144	49,700	50,844	24,224
2021	68,531	8,172	76,703	-	1,144	49,700	50,844	25,858
2022	68,531	9,806	78,337	-	1,144	49,700	50,844	27,493
2023	68,531	11,440	79,971	-	1,144	49,700	50,844	29,127
2024	68,531	13,075	81,606	-	1,144	49,700	50,844	30,761
2025	68,531	14,709	83,240	-	1,144	49,700	50,844	32,396
2026	68,531	16,343	84,874	-	1,144	49,700	50,844	34,030
2027	68,531	16,343	84,874	-	1,144	49,700	50,844	34,030
2028	68,531	16,343	84,874	-	1,144	49,700	50,844	34,030
2029	68,531	16,343	84,874	-	1,144	49,700	50,844	34,030
2030	68,531	16,343	84,874	-	1,144	49,700	50,844	34,030
2031	68,531	16,343	84,874	-	1,144	49,700	50,844	34,030
2032	68,531	16,343	84,874	-	1,144	49,700	50,844	34,030
2033	68,531	16,343	84,874	-	1,144	49,700	50,844	34,030
2034	68,531	16,343	84,874	-	1,144	49,700	50,844	34,030
2035	68,531	16,343	84,874	-	1,144	49,700	50,844	34,030
2036	68,531	16,343	84,874	-	1,144	49,700	50,844	34,030
2037	51,398	12,257	63,656	(45,769)	858	37,275	(7,636)	71,291
				EIRR				**22.1%**

EIRR = economic internal rate of return, IPP = independent power producers, O&M = operation and maintenace.
Source: Asian Development Bank.

C. Sensitivity Assessment

16. **Sensitivity and risk analysis.** The risks to the project's achievement of the above EIRR were identified from both cost and benefit sides. Cost-side risks include increases in capital and operating costs, and delays in commissioning. On the benefit side, consumers' WTP is derived from the forecasts of their electricity demands in the coming years. If the northern states experience significantly lower economic growth that dampens the demand for electricity, consumers' WTP and the program benefits would be lower.

17. The sensitivity of the EIRR was tested for each of the risks identified. EIRR exceeds 12% in all cases. The EIRR sensitivity results are shown in Table 3. Based on these results, investments for the project appear economically robust.

Table 3: Sensitivity Analysis

Sensitivity parameter	Variation (%)	EIRR (%)
Base Case		22.1
1. Capital Cost Increase	+15%	20.2
2. O&M Increase	+10%	22.1
3. WTP reduction	-10%	18.2
4. RCS reduction	-10%	21.5
5. Delay	+1 year	19.7
6. Combined 1 to 5		14.1

EIRR = economic internal rate of return, O&M = operation and maintenance, RCS = resource cost savings, WTP = willingness to pay.
Source: Asian Development Bank estimates.

18. **Distribution analysis.** The distribution of costs and benefits among stakeholders was assessed by comparing constant price financial costs and benefits to economic costs and benefits, both discounted at 12%. Consumers and India's economy benefit from a resource cost saving as output from the project displaces more expensive energy sources. The financial cost of unskilled labor exceeds its opportunity cost, with the difference reflecting a net gain to unskilled labor participating in the project. Overall, the economic net present value exceeds the financial net present value by Rs76,979 million. Consumers are the greatest beneficiary, with net benefits of about Rs40,636 million and the country's economy benefits by Rs35,408 million. Table 4 summarizes the gains and losses to the stakeholders from the investment program.

Table 4: Distribution of Program Effects
(Rs million)

	Net present value at 12% (Rs millions)			Distribution to affected groups (Rs millions)			
	Economic	Financial	Difference	Power sector	Government economy	Unskilled labor	Electricity consumers
Benefits							
Incremental consumption	293,598		293,598				293,598
Resource cost savings	48,012		48,012		17,659		30,354
Power Sector Revenue		66,762	(66,762)				(66,762)
Costs							
Investment	49,523	65,243	(15,720)		15,720		
IPP	216,553		216,553				(216,553)
Unskilled Labor	2,856	3,790	(934)			934	
O&M	4,745	6,775	(2,029)		2,029		
Net Benefits	**67,933**	**(9,046)**	**76,979**	**(905)**	**35,408**	**934**	**40,636**

IPP = independent power producer, O&M = operation and maintenance.
Source: Asian Development Bank estimates.

19. **Sustainability.** The project's economic benefit flow is considered sustainable, based on POWERGRID's strong financial position and technical competency. POWERGRID is a well-established organization and it has performed well in procuring plant, goods, and works for transmission systems in the past. The project is subject to and supported by a transparent tariff-setting regime that permits full recovery of efficient costs. This tariff regime will ensure that POWERGRID can implement its proposed investment project knowing that capital and operating costs are recoverable and that it will earn an acceptable return on capital.

D. Conclusion

20. The economic analysis confirms that the investment for the project is based on the least cost expansion plan and is economically viable. Sensitivity and distribution analyses also demonstrate that the project is economically viable.