

**National Transmission and Despatch Company Limited**



# **National Power System Expansion Plan 2011 - 2030**

## **Final Report Executive Summary**

**504760-01-ES  
2011**



**SNC • LAVALIN**

**Prepared by**

**SNC-Lavalin International Inc.  
in association with**

**National Engineering Services Pakistan (PVT) Limited**







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**LIST OF ABBREVIATIONS AND DEFINITIONS****Abbreviations:**

ADB	Asian Development Bank
AEDB	Alternative Energy Development Board
cct-km	Circuit-kilometre
Consultant	SNC-Lavalin, Transmission and Distribution Group
DISCO	Distribution Company
DSM	Demand Side Management
GDP	Gross Domestic Product
GENCO	Generation Company
HPP	Hydel (or Hydro) Power Project
HSFO	High-Sulphur Furnace Oil
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IEEE	Institute of Electrical and Electronic Engineers
kA	Kilo-ampere
KESC	Karachi Electric Supply Company
km	Kilometre
KPT	Karachi Port Trust
kV	Kilovolt
MMcfd	Million cubic feet per day
MOU	Memorandum of Understanding
MT	Metric Tonnes
MTOE	Million Tons of Oil Equivalent
MVA	Mega volt-amperes
MWh	Megawatt-hour or 1,000 kilowatt-hours
NEPRA	National Electric Power Regulatory Authority
NESPAK	National Engineering Services Pakistan (Pvt) Limited
NPP	National Power Plan, prepared by Acres International Limited in 1994
NTDC	National Transmission and Despatch Company
OGDCL	Oil and Gas Development Company Limited
P.P.	Power Project
PAEC	Pakistan Atomic Energy Commission
PARCO	Pak-Arab Refinery Company
PEPCO	Pakistan Electric Power Company



PPIB	Private Power and Infrastructure Board
PPL	Pakistan Petroleum Limited
PQA	Port Qasim Authority
PSO	Pakistan State Oil
PSS/E	Power System Simulation
RFO	Residual Furnace Oil
SIL	Surge Impedance Load
SNGPL	Sui Northern Gas Pipeline Limited
SSGCL	Sui Southern Gas Company Limited
SYPCO	Generation planning software (System Production Costing)
TAVANIR	The Iranian Electric Utility
WAPDA	Water and Power Development Authority

**S.1 Introduction**

The National Transmission and Despatch Company (NTDC) contracted with SNC-Lavalin to develop a National Power System Expansion Plan (NPSEP) for the period 2011-12 through 2029-30 taking into account technical, economic and environmental issues. There have been no major updates to the previous National Power Plan which was prepared in 1994. Due to persistent power shortages, the need for an expansion plan was urgent and thus only six months were allotted to develop this plan. This plan was developed during the period December 1, 2010 to May 31, 2011.

The scope of the plan is to determine new generation facilities and transmission required to meet the future load growth. Based on the load forecast prepared by NTDC and reviewed by SNC-Lavalin, a least-cost generation expansion plan has been prepared taking into consideration government policies and environmental considerations. An indicative transmission expansion plan to evacuate power was developed using the generation expansion plan to 2030 and the network reinforcement requirements for the DISCOs up to 2020. The generation and transmission plans were the key inputs in developing the financial plan and the annual revenue requirements to build and operate the system. The investments required by each DISCO to effectively reduce losses and optimize their systems were also calculated but they do not form a part of the overall investment requirements appearing in the NPSEP. They are provided as information to the DISCOs for their respective tariff preparation.

This executive summary highlights the salient features of the NPSEP and should be read in the context of the main report which provides additional analysis and explanation. The annexures to the main report provide extensive details for each main subject treated in the main report.

Although the results of the analysis are indicative, they provide a solid foundation for planning the future additions to the generation system and transmission network. Given the very short time-frame to produce this plan, it is recommended that more detailed studies and updates be undertaken by NTDC on an ongoing basis in the future.

**S.2 Pakistan Power Sector**

The changed ground realities during the last seventeen years since the previous National Power Plan (1994) have necessitated basic changes in assumptions for preparation of a successful and implementable NPSEP. At the time of preparing this report, there are severe power cuts with little relief in sight until some of the current projects in the pipeline are commissioned. The NPSEP focuses on structural long-term requirements and thus the resolution of the immediate power crisis is not within the scope of this mandate.

The electricity demand has increased from 12,400 MW in 2003 to 20,400 MW in 2010, roughly at the rate of 7.4% per annum. However, during the same period the installed capacity grew from 18,800 MW to only 22,300 MW which is at a rate of 3.2% per year. The inability to meet the demand is exacerbated by the fact that not all the installed capacity is available when most needed due to capacity de-ratings, fuel constraints, forced outages and other operational difficulties such as with transmission line and transformer overloading. Due to the seasonal nature of hydroelectric generation, some of the 6,555 MW (30% of total installed system capacity) of the hydro capacity varies on a seasonal basis. The table below shows the estimated level of load shedding in recent years from no load-shedding in 2003 to almost 23% in 2010.

**Load Shedding Levels**

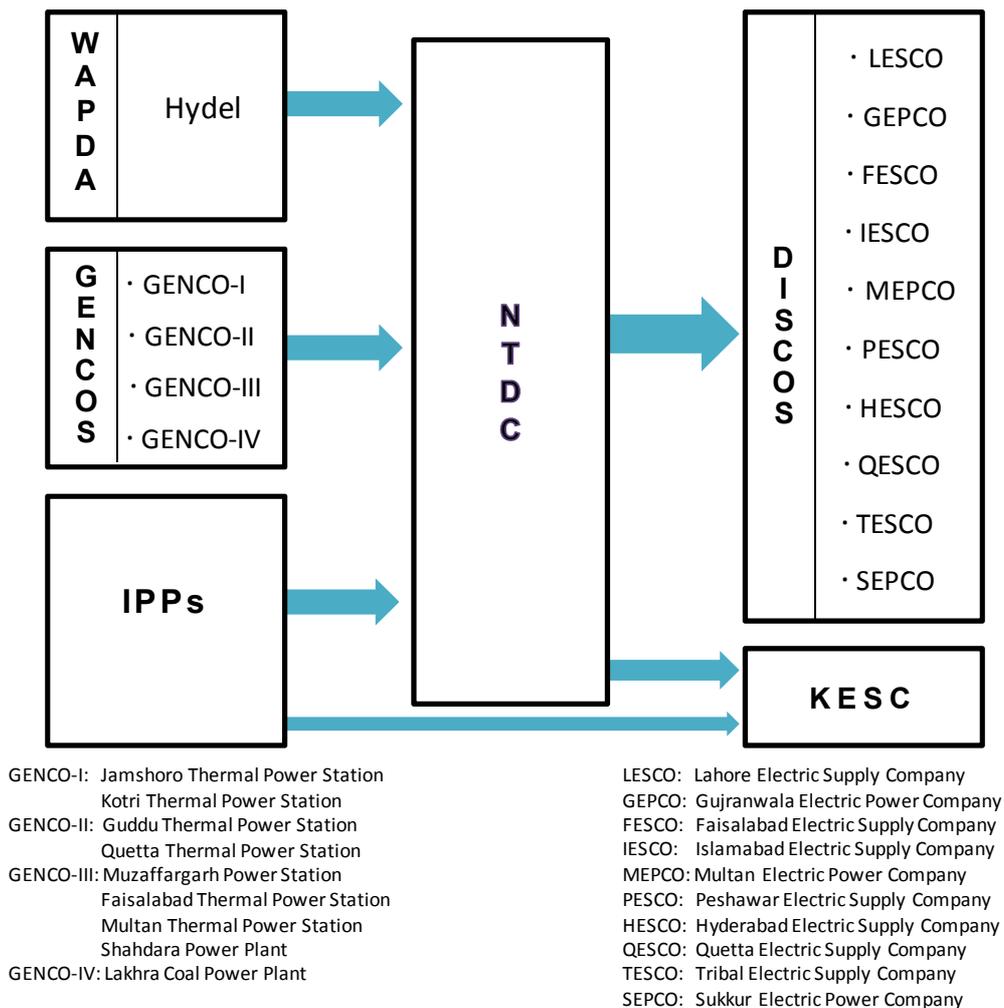
<b>Year</b>	<b>Country Sales (GWh)</b>	<b>Country Load Shedding (GWh)</b>	<b>Total Country Demand (GWh)</b>	<b>Load Shedding %</b>
2003	52,661	-	52,661	0.0%
2004	57,467	520	57,986	0.9%
2005	61,247	265	61,512	0.4%
2006	67,608	1,208	68,815	1.8%
2007	71,947	2,040	73,982	2.8%
2008	72,518	12,578	85,096	14.8%
2009	69,668	18,222	87,890	20.7%
2010	73,595	21,821	95,238	22.9%



**S.2.1 Historical Background**

The Power Sector was restructured in 1998 with the creation of PEPCO (Pakistan Electric Power Company). Prior to 1998, there were two vertically integrated utilities: Karachi Electric Supply Company (KESC) which served the Karachi area and the Water and Power Development Authority (WAPDA) which served the rest of the country. Under this organizational restructuring in accordance with the policy framework of GOP, WAPDA's power wing has been structured into 15 distinct corporate entities comprising of 4 GENCOs, 10 DISCOs and one TransCo (NTDC). At the retail level, these ten DISCOs are responsible for distribution to the end users. KESC is still a vertically integrated utility. KESC meets its overall demand with its own generation plus purchases from NTDC, IPPs and from Karachi Nuclear Power Plant. The current structure of the power sector is shown below.

**Pakistan Power Sector Structure**



Note: KESC is an integrated utility with generation, transmission and distribution. It purchases power from both NTDC and IPPs.

**S.2.2 Government Policy**

The three main objectives of the policy of the Government of Pakistan, namely “Policy for Power Generation Projects 2002”, are:

- To provide sufficient capacity for power generation at the least cost, and to avoid capacity shortfalls that lead to load shedding;
- To encourage and ensure exploitation of indigenous resources, which include renewable energy resources; and
- To be attuned to safeguarding the environment.

The “Natural Gas Policy” and the “Renewable Energy Policy 2006” provide an additional framework that shapes the development of the power sector. The Natural Gas Policy dictates that power plants would get gas supply only after the demands of the domestic, fertilizer and industrial sectors are met. With limited and declining indigenous natural gas reserves, this policy curtails the use of domestic natural gas for future power production. The Renewable Energy Policy mandates the deployment of energy to at least 9,700 MW of new renewable installed capacity by 2030.

With respect to the development of the power sector, the government’s short-term strategy is focused on reducing load shedding, rehabilitating existing plants and implementing fast track projects. The long-term strategy is to develop indigenous resources (i.e. Tharparkar coal, hydro projects and renewable energy projects), keep tariffs at affordable prices, and limit future gas based generation through the use of imported gas or LNG.

**S.2.3 Constraints to Growth**

The shortage of indigenous natural gas will require significant investments in gas pipelines and LNG terminals to import gas to offset declining gas reserves. Further, the use of coal will require large investments in exploiting the existing coal reserves as well as augmenting the current port facilities for imported coal. The problem of limited access to funds for developing this infrastructure as well as for supporting the investments required for power generation and transmission facilities needs to be addressed on an urgent basis if the NPSEP is to be successfully implemented.

**S.3 Planning Criteria**

The planning criteria used for developing the expansion plan is based on the existing international and national guidelines such as the Grid Code to ensure consistency of application in the comparison of alternative schemes. The final base case complies with Government policies that affect the power sector.

**S.3.1 Environmental Considerations**

The NPSEP takes into account current national and international environmental requirements with respect to environmental impact assessments and resettlement requirements at the strategic level. The mitigation costs used in the NPSEP were based on actual studies and readily available data in developing estimates of mitigation costs for the generation and transmission project costs. Field studies were not undertaken in preparing this NPSEP. To the extent possible, compliance to the Government of Pakistan and International Funding Institutions policies and standards formed part of the evaluation.

Some of the projects studied have full environmental studies available while many of them are only in the early planning stages for which environmental studies were not available. Cost data for projects with complete studies which were done over the last 20 years was updated to 2010. These costs then served as a basis for deriving proxy costs for projects that did not have any environmental assessments.

**S.3.2 Fuel Pricing**

The long-term fuel prices derived for the NPSEP were based on data from the Energy Information Administration, the International Energy Agency, the Pakistan Energy Yearbook 2009, and the Inter State Gas Systems (ISGS) adjusted to 2010 price levels. These prices were used in developing the generation plans.



Long-Term Fuel Price Forecasts to the Year 2030

Fuel	Unit	Current	Projection			
		2009-10	2014-15	2019-20	2024-25	2029-30
Imported Crude Oil	\$ / bbl	80	96	110	117	125
Imported Natural Gas	\$ / MMBtu	9	11	12	13	13
Imported LNG	\$ / MMBtu	8	13	14	15	17
Furnace Oil (HSFO)	\$ / MT	507	511	586	622	668
Furnace Oil (LSFO)	\$ / MT	558	562	644	685	735
Diesel	\$ / Ltr	0.76	0.83	0.95	1.01	1.08
Imported Coal	\$ / MT	115	147	165	151	140
Thar Coal (Mined)	\$ / MT	44	44	44	44	44
Nuclear Fuel ( U3O8)	\$ / lb	50	80	60	60	60

S.3.3 Generation Planning Criteria

Plants under construction and those with firm commitments with financial closure were included in the base plan as per their scheduled dates. Other plants were included based on least cost criteria using the system planning model based on a review and ranking of the plants.

Thermal plants were selected based on a screening analysis that takes into account capital cost, operating cost, forced outage rates and economic life of plants. Based on the analysis, the most economical plants for varying capacities were selected using levelized costs.

As there is currently no retirement plan for the existing units, indicative reasonable retirement schedule taking into account the current condition of the existing units and the typical service lifetime of unit types was used.

The generation expansion plan is based on satisfying reliability criteria. **Loss of Load Probability (LOLP)** is the risk associated with having insufficient generation to meet the forecasted load demand. The reliability criterion used was staged to gradually move by 2020-21 to less than 1% or 87.6 hours per year.

After reviewing the historical data and previous studies, 2003-04 was selected for the basis of load profiles as it had no load shedding.

**S.3.4 Transmission Planning Criteria**

The NTDC Grid Code approved by the regulatory authority for the power sector in Pakistan (NEPRA), provides the framework for both the transmission planning and operating criteria. In particular, it addresses issues such as system frequency and voltage level for both normal operating conditions (N-0) and contingency operation conditions (N-1) under steady state and disturbed dynamic/transient conditions.

For this planning study, the DISCO investment plans up to 2015 were available and hence the starting point for the transmission planning was 2015 instead of the normal base year of 2010, therefore the studies for the DISCOs were performed from 2015 to 2020. This assumes that the DISCO system improvement plans up to 2020 will be implemented. Further, planned projects of NTDC yet fully committed were also included in the transmission plan. These projects include the Iran–Pakistan HVDC interconnection, the HVDC lines from Thar to Lahore/Faisalabad and the CASA-1000 HVDC interconnection.

**S.3.5 Distribution Investment Planning Criteria**

The planning criteria of the Secondary Transmission System (66 kV to 132 kV system) requires that the established voltage criteria must be satisfied under both the normal operating conditions (N-0: no equipment out of service) and the contingency operating conditions (N-1: one line or transformer out of service) for the projected loads.

The results of the DISCO expansion plan for 2020 are the starting point for developing the primary transmission plan to the horizon year at 2030.

**S.3.6 Investment and Financial Planning Criteria**

The electric energy sales forecast, the load forecast and the system expansion plan (Generation and Transmission Plan) are the key inputs to the financial plan. The system expansion plan is a least-cost plan to serve Pakistan's load growth and current load over the period 2011 to 2030.

The overall objective for the financial plan is to determine the financial implications for the power sector over the course of the 20 year period (2011 to 2030). The analysis of this plan estimates the tariff at the generation and transmission levels required to recover the financial costs of the investments in the power sector in generation and transmission.



It has been assumed that the overall financing has been done on commercial basis with the funding for investments with debt and equity. This may not be the case since typically new hydro projects are carried out by the Pakistan government and the thermal projects by the private sector. In order to reflect the true cost of power from thermal and hydro plants, the same financing has been assumed for both hydro and thermal plants to ensure that all the projects are on equal commercial and financial footing.

The costs for owning and operating the DISCOs will need to be added to the costs of generation and transmission to determine the overall cost of supply to the end user. The distribution costs reflect the current operating, maintenance, billing and commercial costs of the distribution systems with an adjustment for improved efficiency.

The key criteria used in the development of the financial plan are summarized below.

<b>Criteria</b>	<b>Value Used</b>
Inflation Rate	2%
Discount Rate	10%
Rate of Return	15% on Equity
Cost of borrowing	8%/annum
Debt/Equity Ratio for financing	70% / 30%
Loan repayment period	10 years
Exchange rate	80 PAK Rupees = 1 US\$ (2010)
Asset Life	
• Hydro	50 years
• Thermal	30 years
• Transmission	40 years

### **S.3.7 Constraints**

Infrastructure to support fuel supply is a major constraint. Generation costs from coal will be less than 50% of other fuels and hence there will be a move away from using furnace and crude oil to a coal and gas generation mix for thermal plants. Thus, it is assumed that new infrastructure to import and distribute coal, LNG and natural gas will be in place as required.

Access to investment funds may be an additional constraint as the level of investments required to catch up are very high. Funding constraints have not been considered in this report.



**S.4 Load Forecast**

The load forecast for this study was prepared by the NTDC load forecast team using standard regression methods. This team has been updating the forecast for the last seventeen years. The methodology and the forecast results were validated by SNC-Lavalin.

The load forecast projects the load in both energy and peak demand to 2035 at the country level. The regression analysis uses historical data adjusted for load shedding. The long-term projections include four scenarios covering base load (most probable), high load, low load and base load with DSM.

The key inputs to the forecast are demographic and economic variables such as:

- Total GDP and GDP by sector;
- Electricity sales by customer class;
- Population, number of customers;
- Price elasticity; and
- Load profiles (load factor, loss reduction programs, etc.).

In preparing the load forecast, losses are assumed to drop from 5.1% (2010) to 4.5% (2015) at the transmission level and from 17.1% (2010) to 10.3% (2019) for distribution. The forecast shows that the load will be more than double in the next ten years and grow to over six times the current demand by 2035, as summarized in the table below:

**Base Case Load Growth\***

<b>Base Case</b>	<b>2009-10</b>	<b>2019-20</b>	<b>2034-35</b>	<b>Growth 2010-2035</b>
Sales (TWh)	107	254	738	8.1%
Generation (TWh)	140	307	890	7.7%
Peak Load (MW)	22,000	50,000	150,000	7.9%

\* These are rounded numbers and include estimates for self-generation

**Category Wise Break-Down of Projected Load**

Category	2009-10	2034-35	Change
Domestic	42%	46%	+4%
Industrial	35%	37%	+2%
Agriculture	12%	9%	-3%
Commercial	7%	4%	-3%
Other	4%	4%	0%
Per Capita Consumption	640 kWh	2,540 kWh	+1,900 kWh

The category-wise breakdown of the projected load shows that the contribution of the domestic load to the total load will increase from 42% in 2009-10 to 46% by 2034-35. Over the same period the share of the industrial load will increase from 35% to 37%. The share of the agricultural and commercial sectors is projected to decrease over the period. The power consumption of the industrial and residential sectors is projected to grow at a rate of about 8.5% per annum while the agricultural and commercial sectors are projected to increase at somewhat lower rates.

A striking result shows that the per capita consumption of the country is expected to increase from 640 kWh/year to 2,540 kWh/year over the next 25 years.

The load forecast at the national level shows that the average base case growth for energy is 8.2% over the next ten years and then 7.7% thereafter as shown below.

**Load Forecast (Generation Requirements – TWh)\***

Scenario	2009-10	2019-20	2029-30	Δ 2010/ 2020 per year	Δ 2020/ 2030 per year
Base Case	140	307	647	8.2%	7.7%
High Growth	140	339	770	9.2%	8.5%
Low Growth	140	263	496	6.5%	6.5%
Base Case with DSM	140	307	647	8.2%	7.7%

\* Load Forecast includes PEPCO, KESC and Self-Generation

During the first ten years up to 2020, the energy requirements will more than double, however the difference between the high and base scenarios as well as the base and low load growth scenarios is relatively small.



The preparation of the load forecast is based on energy related factors and not peak loads. Peak demand takes into account the contribution of each customer class load profile. The projected growth in the peak demand generally follows the energy forecast but takes the system load factor into account. Over the planning horizon, it is assumed that the load factor will decrease from 72% to 68%.

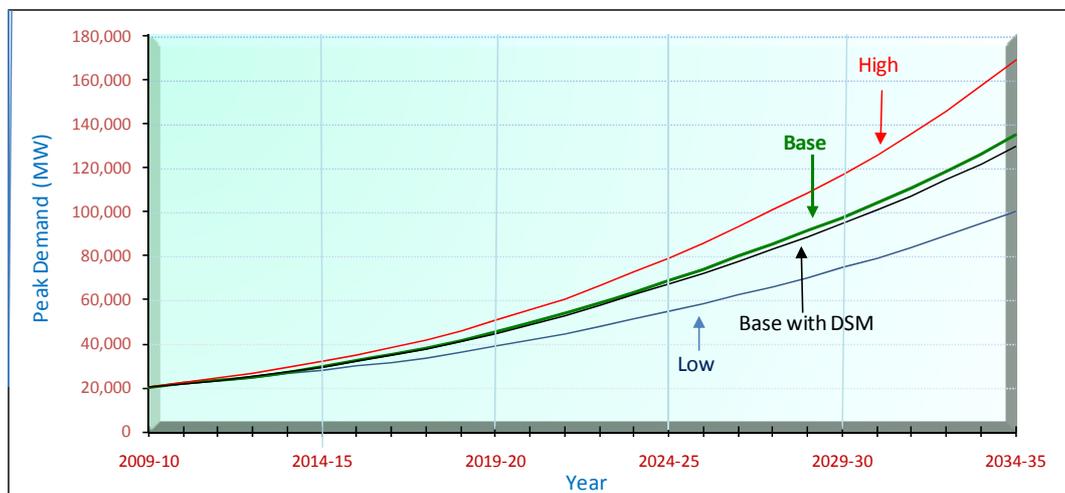
The DSM scenario used in this forecast is based on current policies which assume that DSM programs will primarily reduce the peak demand but not the energy. Investments in DSM represent one of the most cost effective measures in reducing energy requirements as well as peak demand and should therefore be pursued aggressively. With appropriate funding and implementation of DSM strategies, there would be a reduction in both energy and peak demand that would then further reduce the projected growth in demand and energy from the current Base Case with DSM. The growth in peak demand is shown in the table and figure below.

**Load Forecast (Peak Load – MW)\***

Scenario	2009-10	2019-20	2029-30	Δ 2010/ 2020 per year	Δ 2020/ 2030 per year
Base Case	22,251	49,824	107,477	8.4%	8.0%
High Growth	22,251	54,998	128,039	9.5%	8.8%
Low Growth	22,251	42,612	82,457	6.7%	6.8%
Base Case with DSM	22,251	49,146	104,617	8.2%	7.8%

\* Load Forecast includes PEPCO, KESC and Self-Generation

**Peak Demand Forecast (Country Wise)**



**S.5 Generation Plan**

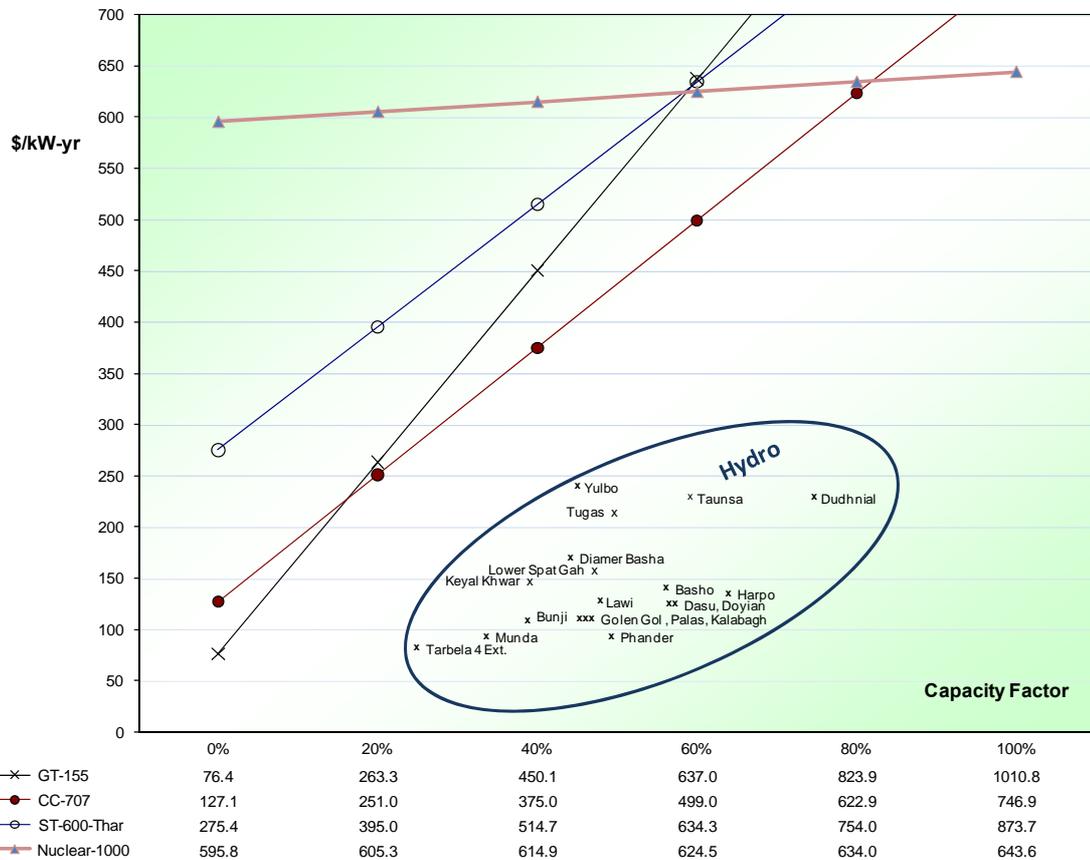
The investment and operational costs of generating facilities represent the largest single cost to the power sector. The objective of the least-cost planning exercise was to find the optimal generation mix that will reliably supply the customer load over the entire planning horizon to the year 2029-30. A diversified generation mix based with priority given to the development of indigenous resources increases self-sufficiency while providing stability in costs over the long-term. Currently, the primary source of energy supply has come from natural gas, oil, hydro and nuclear. In recent years, coal has started to become an alternative base load fuel and increased attention is being given to use renewable sources.

The choice of generation options took into account: system size; variation in daily and seasonal peak loads; system reliability requirements; operational and maintenance constraints; fuel availability; environmental constraints; and other factors. The expansion of the generation facilities was based on a selection of hydro, thermal and renewable resources. The data for candidate plants was provided by GENCOs, WAPDA, PPIB, PAEC and AEDB. These candidate plants were ranked based on levelized life-cycle costs as shown in the graph below.

The ranking showed that most of the hydro plants are economical compared to thermal alternatives operating at the same capacity factors. The analysis showed that 155 MW gas turbines were cost effective when operating at capacity factors lower than 17%, 707 MW combined-cycle plants were most economic when operating between capacity factors from 17% to 80%, and nuclear plants were least costly to operate above 80% capacity factor. As part of the policy to promote use of indigenous resources, a 600 MW steam turbine using Thar coal was also one of the candidate plants for generation expansion. Using the current project prices for fuel, the lowest cost plants are combined cycle plants. However, with decreasing gas reserves and government policy to prioritize gas allocation for non-power uses, over-dependency on LNG or imported gas is not recommended. The use of indigenous resources such as coal limits exposure to extreme price fluctuations in fuel prices.



### Screening Curve Analysis for Hydro and Thermal Plants



Hydro plants were ranked according to their levelized cost and for the most part were deployed in the plan based on the schedule prepared by WAPDA taking into account the proper lead time to complete the proposed hydro projects. The screening analysis showed that most of the hydro plants were more economical than the thermal plants. The completion level of studies done on each candidate hydro plant was a determining factor in the timing of the deployment of the plants in the generation plan. The criteria shown in the table below was the basis for establishing the earliest commissioning date for each plant.

### Commissioning Dates of Hydro Plants

Category	Current Identified Status	Lead Time
A	Under construction	As per schedule
B	Ready for implementation	Construction period plus 1-2 years
C	Detailed design and tender documents	Construction period plus 4 years
D	Under study	Construction period plus 6 years
E	Desk studies	Construction period plus 8 years

**S.5.1 Least Cost Indicative Generation Plan**

The generation plan was developed using a system planning and production costing (SYPCO) model to evaluate numerous alternatives. Based on generation, fuel and environmental data provided by WAPDA and other agencies, a least-cost expansion plan was developed using Loss of Load Probability (LOLP) criteria to ensure that the installed capacity can reliably meet the load each year of the plan. The model uses monthly load duration curves based on hourly data to simulate unit by unit modelling of all hydro and thermal plants.

The least-cost generation plan was developed through extensive analysis based on simulations of alternative plans and then selecting the plan that provides the least cost option. Two initial generation expansion simulations were developed as exploratory plans to assess the impact of the current planned capacity additions as well as optimized capacity additions without constraints. One of the key criteria in evaluating the plans was to ensure that acceptable reliability indices are attained in each year.

**Preliminary Generation Projects Scenario:** These simulations are based on the existing planned generation in-service dates. If current proposed projects on the list proceed as expected, the current deficit in installed capacity will be eliminated by 2016-17 and will provide acceptable generation reliability levels up to 2019-20. After that time, the reliability levels would fall short without adequate new capacity. This scenario provided useful insight into the Pakistan system but was dropped since reliability criteria were not satisfied throughout the study horizon period.

**Unconstrained Least-Cost Generation Plan:** Using the previous scenario as a starting point, new generation was added as required to ensure the target reliability levels are attained. This involved adjusting some of the in-service dates of a number of alternatives operating at the same capacity factors as required to meet reliability targets while maintaining the lowest system investment and production costs. This scenario provided a strong indication of the installed capacity required to satisfy the demand but was dropped since some of the policy and infrastructure constraints were violated.

**Base Case – Constrained Least-Cost Generation Plan:** The constrained least-cost generation plan is a variant of the unconstrained plan that takes into account GoP policy considerations and infrastructure constraints. This plan was optimized to ensure the lowest production and investment cost while satisfying reliability targets. The plan shows that



almost 100,000 MW of installed capacity needs to be installed to satisfy the load growth and also to replace the almost 7,000 MW of retiring plants.

**Net Capacity Additions from 2011-12 through 2029-30**

<b>Net Capacity Additions (MW)</b>	<b>2011-12 to 2020-21</b>	<b>2021-22 to 2029-30</b>	<b>Total</b>
Hydro Plants	11,035	23,956	34,991
Gas Turbines	267	921	1,188
Combined Cycle	5,930	4,136	10,067
Steam Turbines (coal)	15,661	22,113	37,774
Bagass and Bio Waste Plants	100	0	100
Nuclear	2,840	3,760	6,600
Wind	1,800	3,600	5,400
Interconnections	2,000	0	2,000
<b>Total Net Capacity Additions</b>	<b>39,634</b>	<b>58,486</b>	<b>98,120</b>
Retirements	2,423	4,512	6,936

The least-cost indicative generation plan shows that the current installed capacity to meet the demand in 2020-21 will have to be more than double and increase by a factor of five to meet the 2029-30 load. The most significant changes in the generation mix will be the reduction of thermal power based on oil currently at 37% to 6% in 2029-30 and similarly, gas-based generation will decrease from 31% to 11%. The oil and gas based generation will be to a large extent replaced by coal based plants.

In keeping with Government policy on energy from renewable sources, it is expected that about 5,000 MW of power will be provided by wind. However, it should be noted that while wind power increases the total installed capacity, it produces non-firm energy which does not increase the effective capacity of the system.

The net generating capacity (site-rating) by generation source resulting from the plan for representative years is shown below.

**Base Case - Least Cost Generation Plan**

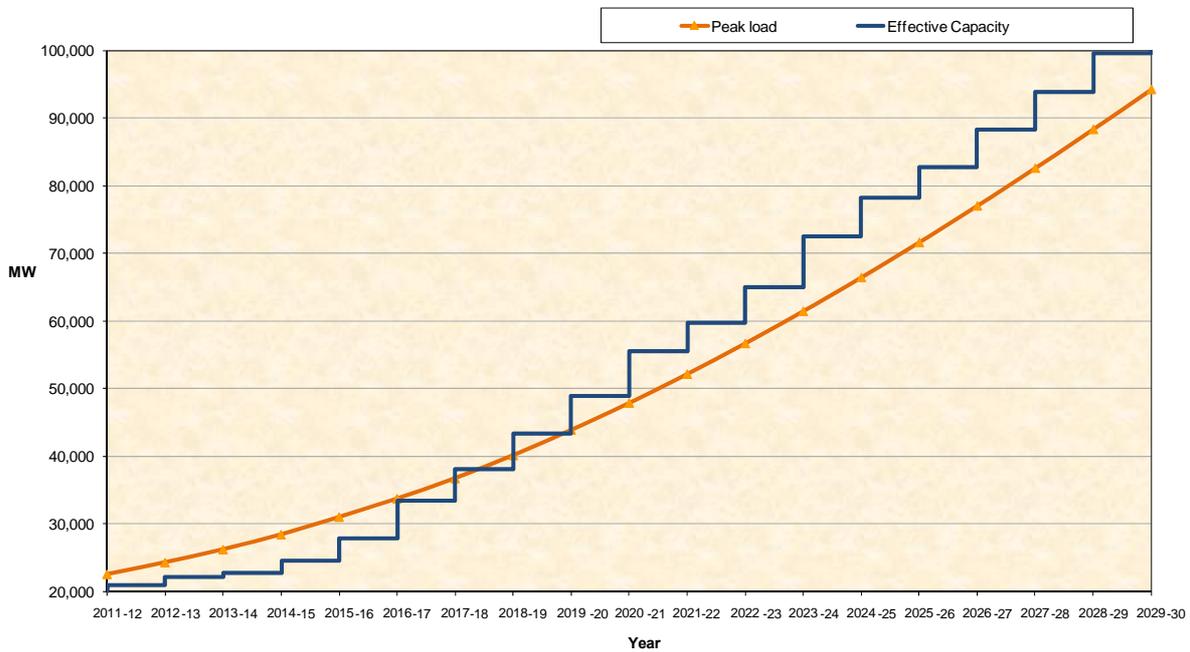
	2010-11		2020-21		2029-30	
	(MW)	(%)	(MW)	(%)	(MW)	(%)
Hydro	6,555	31%	17,590	30%	41,546	37%
Thermal – gas	6,571	31%	11,242	19%	12,015	11%
Thermal – oil	7,838	37%	7,056	12%	6,855	6%
Thermal – coal	30	0.1%	15,691	27%	37,774	34%
Bagass and Bio Waste Plants	0	0%	100	0.2%	100	0.1%
Nuclear	461	2%	3,187	5%	6,947	6%
Wind	0	0%	1,800	3%	5,400	5%
Imports	0	0%	2,000	3%	2,000	2%
<b>Total</b>	<b>21,455</b>	<b>100%</b>	<b>58,866</b>	<b>100%</b>	<b>112,639</b>	<b>100%</b>

The base case least-cost generation plan shown in the graph below indicates that starting in 2017-18; the net generating capacity will exceed the peak demand of the system.

Sensitivity studies on key parameters utilized in the base case validated the robustness of the proposed solution. The impact of changing the key parameters did not have any major impact on the sequencing of the proposed least cost solutions. Parameters varied include: discount rate; changes in fuel cost; capital cost; high and low load forecast scenarios. The impact of using the high load growth scenario showed that some of the units needed to be advanced one or two years while using a low load growth scenario delays the commission date of some of the units. In the first ten years of the proposed plan, the differences between the high, base and low scenarios is not that significant and hence it is relatively simple to adjust the base case plan according to the prevailing load demands at any given time.



**Graphical Representation of Least Cost Generation Plan**



**S.5.2 Fuel Requirements**

The Base Case will require over the study period 9.2 million MMcf of natural gas, 79 million tonnes of furnace oil, 1,621 million tonnes of coal, 292 thousand tonnes of diesel, and 9.3 thousand tonnes of U<sub>3</sub>O<sub>8</sub>. The power sector will need to coordinate on an ongoing basis with the fuel and infrastructure providers to ensure that sufficient fuel supplies and infrastructure will be available to implement the power sector expansion plan.

**Fuel Requirement by Fuel Type**

Period	NG (million m <sup>3</sup> )	NG (million MMcf)	FO (million ton)	Thar coal (million ton)	Dies (Ton)	U <sub>3</sub> O <sub>8</sub> (Ton)
2011-12 to 2020-21	179,622	6.3	56.0	309	291,719	1,894
2021-22 to 2029-30	81,830	2.9	22.8	1,312	0	7,360
<b>Total</b>	<b>261,452</b>	<b>9.2</b>	<b>78.8</b>	<b>1,621</b>	<b>291,719</b>	<b>9,253</b>

**S.5.3 Cost of Generation Planning Scenario**

The investment and the operating cost of the generation plan for the entire period was calculated using SYPCO software. It shows that over US\$ 550 billion in 2010 constant US dollars is required to build and operate the generation over the next 19 years. *(Please note that these are economic costs that form the basis of the financial presented in later sections).*

<b>Investment and Production Costs (\$US Million)</b>	<b>2011-12 to 2020-21</b>	<b>2021-22 to 2029-30</b>	<b>Total</b>
Investment Costs	103,667	87,734	191,402
Fuel Costs	129,907	161,085	290,992
O&M Costs	11,500	26,809	38,309
Unserved Energy Charges	26,678	7,511	34,189
<b>Total Generation Costs</b>	<b>271,752</b>	<b>283,140</b>	<b>554,892</b>

**S.6 Transmission Plan**

The transmission expansion plan provides the most technically feasible solution to evacuate power from the generation plants proposed in the least-cost generation expansion plan. It also meets the growing demand of the load centres by reinforcing and extending the existing 500 kV and 220 kV grid. The proposed plan satisfies the NTDC Grid Code reliability criteria in terms of acceptable voltage, frequency, loading of lines and transformers for normal (N-0) and contingency (N-1) conditions both under disturbed dynamic/transient conditions and steady state conditions.

**S.6.1 Methodology**

The reference base case was the 132 kV DISCO expansion plan for the year 2020 which was superimposed on the NTDC 220 kV and 500 kV networks to identify the optimal locations new 500 / 220 kV and 220/132 kV substations. Ongoing, committed and planned extensions were also included as were other planned projects currently under study. These projects include the 1000 MW interconnection from Iran, the 1000 MW import from CASA, the planned evacuation of power from planned hydro projects and the interconnection to evacuate power from the Thar coal fields.



The proposed network was developed for the horizon year (2030) using PSS/E software. Detailed analysis for the years 2016, 2020, 2025 and 2030 confirmed the staging of the investments required to provide a reliable transmission network. Cases for high water and low water years were simulated to test the robustness of the system under both normal and contingency conditions. This was confirmed from load flow, short-circuit and transient stability analyses.

**S.6.2 Results**

The following Table shows the total additional reinforcements required for the NTDC network till the year 2030 over and above the ongoing, committed and planned till 2016-17:

<b>Items*</b>	<b>Between 2017-2020</b>	<b>Between 2021-2030</b>
220 kV D/C lines (kM)	270	2,623
500 kV D/C Lines (kM)	5,394	6,700
220/132 kV transformers/substations (MVA)	19,850	79,600
500/220 kV transformers/substations (MVA)	25,800	68,150
± 500 kV HVDC Bipole Converters (MW)	2X(1X1,000)	–
±500kV HVDC Bipole Transmission line (kM)	654	
± 600 kV HVDC Bipole Converters (MW)	2X(2X4,000)	6x(2x4,000)
±600kV HVDC Bipole Transmission line (kM)	2,000	5,770

\* Lengths for lines crossing international boundaries only include Pakistan component

**S.6.3 Costs**

The cost of implementing the transmission upgrades is US\$ 27 billion which are summarized in the table below.

<b>Item*</b>	<b>Million PKR</b>	<b>Million USD</b>
Projects already committed /Planned to be completed by 2016-17 but not yet funded	428,000	5,350
Projects proposed from 2017 to 2020	569,440	7,118
Projects proposed from 2021 to 2030	1,163,360	14,542
<b>Total</b>	<b>2,160,800</b>	<b>27,010</b>

\* Cost for lines crossing international boundaries only include Pakistan component. Costs are based on US\$ 1= PKR 80

**S.7 Distribution Investment**

The proposed distribution system upgrades in each of the DISCOs was carried out in coordination with the development of the National Transmission Master Plan. The additional reinforcements required in each DISCO at secondary voltages for the year 2015, 2016, 2018 and 2020 were identified. In addition, the estimate of distribution investments was included as part of the new transmission for handling the power transmitted between the high voltage systems and the load centres

Working closely with teams of counterparts from the DISCOs, the system upgrades for the loads of 2015, 2016, 2018 and 2020, under both normal and contingency conditions for each DISCO were developed after an evaluation of the DISCO secondary transmission system.

The cost of the proposed system reinforcements was estimated to be about PKR 116,000 million which is equal to US\$ 1,451 million for all the DISCOs combined. While this costing information is not directly used in the NPSEP, it does indicate the level of investment that the DISCOs should make so NTDC can strengthen, reinforce and expand the existing transmission plan as per the NPSEP.

**S.8 Financial Plan**

The financial plan provides an indication of the overall level of investment and financing required to implement the generation and transmission expansion plan. It is also used to ascertain the impact of the generation and transmission expansion plans on the tariffs.

The total capital and operating expenditures for hydro generation, thermal generation, and transmission are provided in the table below for the periods 2011 – 2019 and 2020 - 2029 in both nominal and discounted terms.

The results regarding the generation and transmission investment outlays indicate that the total generation costs over the planning period would be over 647 billion USD, while the total expenditure on the transmission system is expected to be over 34 billion USD. In Present Value terms with a discount rate of 10%, these values are 248 billion USD and 14 billion USD respectively.



**Generation / Transmission Expansion Plan Costs - 2011 through 2030 (million USD)**

	Without Discounting			With Discounting at 10%		
	2011-12 to 2019-20	2020-21 to 2029-30	Total	2011-12 to 2019-20	2020-21 to 2029-30	Total
Hydro - Capex	39 677	45 730	85 407	22 704	14 353	37 057
Hydro - Op Exp	1 789	10 278	12 068	1 046	2 427	3 473
Thermal - Capex	62 269	85 746	148 015	36 841	22 480	59 321
Thermal - Op Exp	8 935	28 615	37 550	5 256	6 908	12 164
Thermal–Fuel Exp	127 667	236 950	364 617	77 855	58 974	136 829
<b>Total Generation</b>	<b>240 337</b>	<b>407 319</b>	<b>647 657</b>	<b>143 702</b>	<b>105 142</b>	<b>248 844</b>
Transmission Capex	12 764	14 764	27 033	7 991	3 791	11 782
Transmission-Op Exp	1 481	5 755	7 236	802	1 395	2 197
Total Transmission	14 245	20 024	34 269	8 794	5 186	13 998
<b>Total Gen &amp; Trans</b>	<b>254 581</b>	<b>427 344</b>	<b>681 125</b>	<b>152 496</b>	<b>110 328</b>	<b>262 823</b>

*Notes: Capex represents the capital expenditures.*

*Op Exp represents the operating expenditures and includes operating and maintenance expenditures.*

As regards the annual investment requirements in the generation and transmission, it ranges from minimum of 306 million USD in 2011 to the maximum of 17,602 million USD in the year 2016. The investment requirements are low in the year 2011 due to the reason that generation capacity would not be added during this year and the investments will be made in transmission network only. The high investments in 2016 are due to the massive investment requirements in the generation capacity. The average annual investment outlay is assessed to be over 11 billion USD. Considering that the GDP of the country was little over 170 billion USD in 2010, these investment requirements will be about 6.4% of the 2010 GDP of the country.

The review of results obtained manifests that the cost of generation from thermal projects throughout the planning period is significantly higher as compared to the cost of hydro generation. The average cost of generation for the hydro plants is estimated to be 6.8 cents/kWh over the planning horizon, while thermal generation costs are computed as 13.1 cents/kWh. The main reason of high thermal generation cost is the inclusion of fuel costs, which constitute a substantial portion in the total thermal generation cost. For hydro plants the production cost is extremely low due to the absence of any fuel requirements thus making the unit cost of generation from hydro plants significantly less as compared to the thermal plants. This implies that allocating capital investment to the hydro plants on a priority



basis and putting emphasis on the development of hydro generation would be a prudent strategy in order to keep the cost of generation low. This would also facilitate in keeping the end-consumer tariff low. In addition, according high priority to hydro generation would have a long-term positive impact on the tariffs as these would not be subjected to the uncertainty of changing fuel prices thus keeping the tariffs relatively more stable.

The financial implications of investment in hydro generation would also be beneficial in the sense that foreign exchange requirements would be relatively lower in the long-term. Considering that a substantial investment for hydro projects is required in civil works, for which indigenous resources can be used, a large portion of financing can be arranged in domestic currency.

The generation cost results indicate that the unit costs of generation during the period 2015 to 2025 would be relatively high, i.e., in the range of 11.5 to 11.8 cents/kWh. This is due to higher investment in the generation capacity during this period as well as due to high production costs from the thermal units. The average cost of generation over the planning period is evaluated as 11.1 cents/kWh.

The transmission investment shows a sharp increase from the period 2010-2015 to the period 2015-2020 due to the large transmission capacity requirements in order to evacuate the power from the generation capacity to be build during this period.

The total supply costs taking into account the technical and commercial losses are assessed to be 15.6, 18.8, 17.5, and 18.1 cents/kWh for the years 2015, 2020, 2025 and 2030 respectively. This implies that the cost of energy supply in the future is going to be considerably high as compared to current values. This will have major implications on the electricity tariffs for all the consumer sectors as tariffs would need to higher than the power supply costs (It is assumed that no subsidy would be provided). Therefore, the implementation of tariffs so that the cost of power supply can be recovered with some margin would be imperative in order to have a viable operation and sustainable development of the power sector.

**S.9 Way Forward**

The NPSEP was completed on a fast track basis and provides a good indication of the level and cost of investments required to adequately and reliably supply the load up to the year 2030. The short time frame of six months to develop the NPSEP in the pattern of the NPP of 1994 a number of approximations be made. New inputs for this revised plan will need to be incorporated on a regular basis to keep the plan alive.

This plan was produced with the collaboration of many counterparts who have received classroom training and hands-on training throughout the duration of this project. The distribution counterparts from the DISCOs who came to the project offices are now in a strong position to update the DISCO investment plans on an annual basis as are the DISCO officers who annually contribute to the preparation of the load forecasts. The current plan provides a good foundation for building in-house capability to decrease dependence on outside consultants.

The NPSEP is a key element in charting the course for future development and needs to remain current. Thus it is recommended to:

- Update the plan on an annual basis;
- Update and validate inputs (i.e. Hydro data, fuel costs, etc.);
- Develop a plan for systematic data collection;
- Develop an annual planning cycle for updating plan;
- Increase regular interaction with all stakeholders;
- Augment capacity of long-term planning cell through systematic training;
- Develop centralized web-based data room; and,
- Examine the impact of prioritizing the development of indigenous resources.







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